

# **Implementation of Distributed Generation Analytic Framework Building Upon NEMS/POEMS**

## **Subtask 2**

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## **Background**

### **Introduction**

This Report follows up on a previous Report, *Framework for Identifying Distributed Resources Markets Consistent with NEMS/POEMS*<sup>1</sup>. That Report discussed the various aspects of the markets for distributed generation and identified the unique characteristics of each of these markets particularly with respect to the modeling of these markets. The Report characterized distributed generation with respect to market segments and how they relate to specific technologies, spatial load issues, temporal load issues, grid connection issues, economic issues, and environmental issues. These were discussed to try to clarify how the distributed generation markets work and interact with the goal of modeling distributed generation in the context of the National Energy Modeling System (NEMS) and the Policy Office Electricity Modeling System (POEMS).

This second Report more directly addresses model code changes and implements a number of them in the preliminary code for the NEMS models. The Report first details the preliminary distributed generation routines that were added to the demand models for the Annual Energy Outlook 2000 and then discusses the various model code changes and enhancements that improve upon that foundation. The Report then describes the changes that were made to the building model code for distributed generation.

### **Evolution of Distributed Generation Markets**

As noted in the first Report, distributed generation has been defined in a wide variety of ways and can cover a great deal of activities. There are many aspects to it, but certainly much of the recent interest evolves from greater access to the grid. State level activities enacting retail wheeling allow customers to purchase electric power more competitively from a variety of suppliers including from distributed generators. In response, the electric power system is evolving in various ways.

The proposed Comprehensive Electricity Competition Act of 1999 (CECA) was recently introduced to further extend competition in electricity markets. The CECA contains several provisions designed to facilitate the adoption of distributed generation technologies. For example, CECA would require distribution utilities to allow distributed power facilities, including combined heat and power, to interconnect to their systems. It clarifies the tax life of distributed power facilities and provides for an 8 percent investment tax credit for highly efficient combined heat and power system for the years 2000 through 2002. CECA also requires net metering for small, on-site renewable generation systems. These provisions are expected to stimulate additional investments in distributed power and should be considered while additional modeling capabilities for distributed generation are developed.

Within its broader definition, distributed generation has been around for quite a few years. In this context it would include the generation of electricity by industrial and commercial entities. These would typically be either as cogeneration, which found its economies in using waste heat, or in generation using a variety of byproducts of industrial processes such as biomass in the paper industry. Under this broader

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<sup>1</sup>This Report was submitted as the first deliverable in this Task. It is dated August 2, 1999.

definition it might also include much of the other recent non-central station generation such as generation by qualifying facilities under PURPA since 1978 and generation by independent power producers more recently.

However, it is a mistake to think that recent interest in distributed generation is related only to freer grid access and to electricity restructuring. It has also been fueled by the emergence of many newer, more efficient, less costly, more accessible modular technologies and the information systems that can control them. It is also fueled by the continuing and building interest in the use of renewables for power generation and the technological advances that have also made renewable technologies more efficient, more reliable, less costly, and more accessible.

### **Introduction to NEMS and POEMS**

The National Energy Modeling System (NEMS)<sup>2</sup> is developed and maintained by the Energy Information Administration (EIA). NEMS is used by the EIA to develop the Annual Energy Outlook (AEO) projections and is also used by EIA to prepare analytical studies for the U.S. Congress and other offices within the Department of Energy. NEMS is a complex energy modeling system but is publicly available for other organizations to use. One example of an external organization working with NEMS is the extension of NEMS to create the Policy Office Electricity Modeling System (POEMS)<sup>3</sup> which substitutes a more detailed electricity model into NEMS. This electricity model, TradeElec, is related to the NEMS electricity model, but is designed specifically to analyze electricity restructuring issues with its much greater regional detail used for the modeling of electricity trading.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years in the future.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. NEMS is a regional system, functioning and reporting at the nine Census division level. The end use demand models and some other components operate at the nine Census division level, but the supply and conversion models operate internally using a variety of other, sector-specific regional definitions. The primary flows of information between these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability. The execution of each of the component modules is controlled by the integrating module which also tests for convergence.

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<sup>2</sup>For a more complete description see *The National Energy Modeling System: An Overview 1998*, DOE/EIA-0581(98), February 1998, Washington, DC. (This is available at [www.eia.doe.gov](http://www.eia.doe.gov).)

<sup>3</sup>For a more complete description see Policy Office Electricity Modeling System (POEMS) Model Documentation, In Support of the Department of Energy's Comprehensive Electricity Competition Plan, ONLOC-99-05, May 1999, Dunn Loring, Virginia. (This is available at [www.onlocationinc.com](http://www.onlocationinc.com).)

The POEMS model is a version of the NEMS which substitutes an alternative electricity model (described above), but otherwise includes all of the other component modules and retains the same integrating module and execution system. For various purposes or analyses, some changes are made to various algorithms in some component modules. The discussion of proposals for and implementation of modeling changes for distributed generation in this Report would be in the context of the NEMS and POEMS models and could be applied to one or the other or both.

### **The Approach in This Report**

As discussed in the first Report, modeling changes to the electricity model distributed generation are not addressed in this task because of the preliminary nature of EIA's recent revisions for the electricity sector. The actual model and code are not yet available and apparently are not being implemented for the AEO 2000. This Report concentrates on the demand models and discusses each of them, however the model code changes are being implemented in the buildings models. The industrial model code is not yet available and we have been working from a presentation at a Working Group meeting.

The NEMS buildings models, residential and commercial, are very different from each other in the approach and structure of their model code in NEMS. However, in the real world they have a lot of similarities in the way that they use energy. They also have a lot of similarities with respect to distributed generation. In the preliminary NEMS modeling they use very similar model code approaches, with differences in the technology slates and characteristics and in the way that they hook back into the sectoral model. Because of this similarity, the concentration here will be on the residential model with areas of potential differences noted.

The next section reprises much of the discussion in the first Report concerning the areas for proposed supplementary modeling of distributed generation for the demand models. This is more focused and identifies how to distill some of the general proposals into specific modeling approaches. The next section of this Report details the preliminary modeling of distributed generation in the residential sector, with a note relating the key differences between it and the commercial sector. The remainder of the Report details modeling changes and their effects.

# **Modeling Needs and Coding Approaches**

## **Introduction**

The extent of distributed generation in the demand sectors in the recent history has been small except for those cases where there are opportunities for cogeneration or where there are waste fuels available. There is a potential for this to change with equipment becoming available that operates on a smaller scale with much greater efficiencies (lower costs) and with the unbundling of electricity generation costs and potentially transmission and distribution costs. The first section below provides a description of the potential areas for distributed generation in each of the demand sectors.

The basic preliminary approach adopted by the NEMS modelers to represent distributed generation in each of the sectors was described in the first Report. In many aspects this ongoing work is only at a testing stage, but the basic approach used in each sector seems appropriate. It was decided that the work being done for this task should follow the approach of working in parallel to supplement the work that is already being done. The NEMS work is very preliminary and is still evolving, so the comments and suggestions for enhancements are made within that context. Some open issues in each sector were noted in the first Report along with suggestions on how they might be addressed. These are briefly repeated in the following sections. In general, these provide areas for modeling, but do not say much about the specific modeling approaches. The specifics are addressed subsequently in this Report. Some of the comments listed below are general and apply to all of the sectors and some are very specific to each sector.

## **Decomposition of End Use Demand**

### **Residential Sector**

The extent of direct investment in distributed generation in the residential sector would be expected to be low. The current amount of distributed generation is small enough that it is not significant in the regional NEMS model and is not counted. The residential sector consists of a large number of relatively small entities that would not ordinarily make the investments for distributed generation. Because the loads are fairly small, the distributed generation technologies would have to be very small in scale. Typically any investment that is made would be made on a small scale to supply electricity to the primary household with some small sales to the grid. Although electricity prices in the residential sector are much higher than in the other sectors and as a consequence make DG more attractive, the fuel costs are also much higher. Also, in the residential sector the cost of capital is generally higher too, but in many cases some of the investment can be made in conjunction with a home loan. There are a number of significant niche markets, however, for users who are off the grid and need electric power and for users who desire to be independent from the grid or who desire to use renewable resources. Some renewable technologies are particularly appropriate because of their potential small scale, but they are not generally purchased because of their high cost. The residential sector has also been targeted with incentives, subsidies, and tax credits which can cause an increase in the penetration of DG. The excess heat from some DG technologies can be captured and used to help defray costs for hot water heating and space heating in season but this is only a small factor.

The residential sector has a fairly peaked load shape, especially in the middle of the heating season and again in the middle of the cooling season. The extent of the peakedness and the degree to which residential consumers face time-of-day prices in the future may be a factor in the use of distributed generation.

Most of the time, the residential sector consumers that are considered for distributed generation are owners of single family housing units because individual multi-family and mobile homes do not have the sites. However, multi-family housing units in large buildings or communities might purchase distributed generation in a joint fashion, on a large scale. In these cases the cost of capital should also be less. This aggregation potential might also be available for single family and mobile home communities.

**Table 1. Residential Sector Units and Loads by Housing Type in 1998**

	<b>Number of Units (Millions)</b>	<b>Electricity Load (Billion Kwh)</b>	<b>Electricity Load per Unit</b>
<b>Single Family Units</b>	71.11	820.0	11.53
<b>Multi-Family Units</b>	25.23	206.9	8.20
<b>Mobile Homes</b>	6.28	78.6	12.51
<b>Total</b>	102.61	1105.5	10.77

Note: The estimates in this table are from an AEO99 run of a standalone NEMS residential model.

### **Commercial Sector**

The commercial sector has some incentive for investment in distributed generation and is structured in a fashion in which investments can be made and financed on a larger scale than for most of residential. The primary incentive is that there are certain areas in the commercial sector in which excess thermal energy can be used for cogeneration. One large source is in district services, but there are many other large-scale buildings or projects that use thermal energy that wouldn't be classified strictly as district services. Key among these are hospitals and education institutions, along with a host of others. Hospitals also have a strong incentive to have high quality reliable power, with backup capability which might lead to distributed generation.

**Table 2. Commercial Sector Units and Loads by Building Type in 1998**

	<b>Floorspace (Billion Square Feet)</b>	<b>Electricity Load (Million Kwh)</b>	<b>Electricity per square foot</b>	<b>Electricity Cogenerate d (Million Kwh)</b>	<b>District Services All Energy (Trillion Btu)</b>
<b>Assembly</b>	6.91	75.39	10.92	0.056	80.6
<b>Education</b>	8.09	97.71	12.08	2.603	101.8
<b>Food Sales</b>	0.68	43.43	64.30	0.000	0.1
<b>Food Service</b>	1.42	67.11	47.44	0.000	5.5
<b>Health Care</b>	1.73	92.22	53.35	0.743	80.8
<b>Lodging</b>	3.80	77.33	20.33	0.081	73.2
<b>Office - Large</b>	5.82	179.71	30.33	0.826	77.8
<b>Office - Small</b>	5.49	134.56	24.52	0.000	15.6
<b>Mercantile/Service</b>	13.30	211.12	15.87	0.000	21.0
<b>Warehouse</b>	8.96	97.15	10.85	0.000	36.6
<b>Other</b>	5.05	115.39	22.87	0.659	71.3
<b>Total</b>	61.23	1191.13	19.45	4.966	564.4

Note: The estimates in this table are from an AEO99 run of a standalone NEMS commercial model.

### **Industrial Sector**

The industrial sector is a long time generator of electricity, using cogeneration and byproducts. The paper industry generates the largest amount of electricity through the use of waste biomass products. It is expected that this would continue and in the future, as the technology becomes available there is a large capacity for generating electricity through black liquor gasification. This would probably lead to greater sales to the grid. Other electricity generation in the industrial sector is through cogeneration where steam requirements and electricity generation are met using the same technology creating much greater efficiencies.

**Table 3. Industrial Sector Loads and Cogeneration by Industry Type in 1998**

	<b>Electricity Load (Million Kwh)</b>	<b>Electricity Cogeneration (Million Kwh)</b>
<b>Non-Manufacturing</b>	150.1	1.35
<b>Food Products</b>	61.5	8.38
<b>Paper Products</b>	69.5	61.9
<b>Chemicals</b>	182.9	46.2
<b>Glass</b>	8.5	0.00
<b>Cement</b>	12.6	0.21
<b>Iron and Steel</b>	47.2	8.03
<b>Aluminum</b>	56.0	5.80
<b>Refinery</b>	32.8	*
<b>Metal Based Durables</b>	180.8	1.96
<b>Other - Non-Intensive</b>	226.0	6.92
<b>Total</b>	1027.9	140.71*

Note: The estimates in this table are from an AEO99 run of a standalone NEMS industrial model.

\* -- Refinery cogeneration was not available and is not included in the total.

### **Potential Areas for Further Work**

The following provides some discussion of potential areas for further work on EIA's preliminary residential sector distributed generation model structure. These were discussed in greater detail in the previous report.

#### **Cross-Cutting Considerations**

There are some issues that must be dealt with in most or all of the sectors.

*Electricity Pricing.* There are at least two aspects to this, the price at which electricity is purchased by end use customers, and the price at which they can sell electricity back to the grid. The overall deciding factor for distributed generation in each sector is whether the cost to generate electricity (minus any revenue generated by selling the electricity) is less than the cost to purchase electricity. However, for various reasons not all end use customers face the average price for electricity and might pay higher prices. One key to the modeling of distributed generation is to capture the customers at the edge of the distribution that face the higher electricity prices.

There will be a greater variance in prices as we move into the future in a world with electricity restructuring and time-of-day electricity prices. This is also especially true if there is unbundling of

electricity sector transmission and distribution costs and those costs are passed through to end use customers. The distributed generation routines in the end use models need to look at the market segments with higher prices to find any market penetration.

The prices that are paid for sales to the grid are not necessarily the end use price. The buildings models reflect this by using a net metering factor for different technologies. There is still some question about whether the generation price should be used and how to use net metering.

*Technology Competition.* The end use models seem to forecast the penetration of each technology independently of the other technologies. The various technologies should be competing against each other. Using something like a nested logit, it would be valuable to compete the various technologies against each other to determine a slate of potential technologies. The cost characteristics for this slate of technologies (perhaps a prototype for all of them) would be compared to the cost of electricity to come up with the overall penetration rate for the whole slate.

*Third Parties.* A third party entering the market (particularly in the buildings sectors) might change the scale of the projects or the financing characteristics of the investments.

*Financial Analysis and Penetration Function.* There may be alternatives to the particular algorithms that are used for the financial analysis and for the penetration function.

*Non-Economic Factors.* It would be useful to have a mechanism to be able to add non-economic factors into the financial analysis, most likely by adding or subtracting a premium prices, costs, or other key variable.

## **Residential Sector**

The modeling approach in the residential sector looks at the various technical and economic characteristics of a variety of distributed generation technologies and does a financial analysis to compare their costs versus the cost for purchased electricity. The results of the financial analysis are used to determine the market penetration of the technologies. An additional amount of penetration that is likely due to niche markets and is not cost based is determined exogenously. At this point it appears that with the current structure there is only a very small penetration of distributed generation into the residential sector.

*Technology Sizing.* The size or scale of the distributed generation technologies or projects might change the cost or other characteristics and make a difference to the outcome of the financial analysis. Ideally, the model might choose an optimal technology sizing for each circumstance.

*Technologies Slate.* Some technologies might be added to the slate of technologies in the residential model, such as conventional (reciprocating engines) gas and oil generators.

*Existing Housing Units.* The endogenously calculated technology penetration rate is applied in each year to new housing units only. There is probably some penetration that might be expected in existing housing units. These may face a different cost of capital since it is less likely that the distributed generation costs would be financed as part of a home loan. It appears from discussions with NEMS modelers that they are already working on adding structure to evaluate these technologies in existing housing units.

*Multi-Family Housing Units.* All penetration of distributed generation technologies is applied to single-family housing units. There may be some segment of multi-family housing, specifically large buildings and/or clusters of buildings, in which investments are made on a larger scale to be shared by all the units in the buildings. This would be more like the activity in the commercial sector. The scale of the technologies would be much larger, and capital might be more available and at a lower cost. This might also apply to other types of housing units if there is some kind of "community" activity.

## **Commercial Sector**

The modeling approach in the commercial sector is basically the same as that in the residential sector, with an economic analysis as well as an exogenous penetration. At this point it appears that the result will be only a very small penetration of distributed generation into the commercial sector.

*Technology Sizing.* The size or scale of the distributed generation technologies or projects might change the cost or other characteristics and make a difference to the outcome of the financial analysis, as in the residential sector. Ideally, the model might choose an optimal technology sizing for each circumstance.

*District Services.* One segment of the market for cogeneration in the commercial sector is that of district services. It might be useful to rethink the modeling of district services, and how it relates to cogeneration. However, although there is some anecdotal evidence of growth in district services, most seem to think there is not much here.

*Building Types.* Perhaps certain building types are more likely to use distributed generation, such as hospitals, educational institutions, and government buildings.

## **Industrial Sector**

The modeling approach in the industrial model looks at the various technical and economic characteristics of natural gas combustion turbines and does a financial analysis to compare the costs versus the cost for purchased electricity. The results of the financial analysis are used to determine the market penetration of the technology. An additional amount of distributed generation is due to the use of byproducts in the paper industry.

*Technologies Slate.* Some technologies might be added to the slate of technologies in the industrial model. The industrial model only considers natural gas combustion turbines for distributed generation (outside of the paper industry). The model could model additional technologies, for example reciprocating engines and black liquor gasification in the paper industry.

*Sales to the Grid.* There may be some significant markets that involve sales to the grid. Currently the fraction of sales to the grid is being imposed based on historical sales rather than on economic value.

*Oil Sectors.* The refinery sector in NEMS is separate from the industrial sector, but energy consumed in the refinery sector is accounted for in the industrial sector. Cogeneration is modeled in the refinery sector and in oil and gas production sectors and is passed to the industrial model. Is this as integrated as it should be?

## **Proposed Modeling Activities**

As noted above, the most useful approach for modeling would be to work in parallel to supplement the work that is already ongoing in NEMS. We have noted a variety of issues in the first Report (summarized above) that might be worthy of some additional thought and work. Those that might be most tractable and of the greatest benefit and which can be implemented in the code are discussed below.

The various modeling activities seem to fall into five somewhat general groups of activities, with one of the groups a catchall. These are discussed in detail in the implementation section of this Report.

### **Housekeeping**

These activities include a variety of coding cleanups and changes, the addition of include files, the cleaning up existing input files, putting some hardwired variables into the input file, designing and adding new reporting, etc. These activities do not change the structure, flow, or results of the model.

### **Full Housing Unit Coverage**

The preliminary distributed generation routine in the NEMS residential model applies only to new single family housing units. There are a large number of existing housing units and a large number of multi-family and mobile home housing units to which the model does not apply. It is likely that the average potential for distributed generation is less in these other housing units, but there may be pockets in each of these where there is some potential. For example, large projects in multi-family housing might be a significant source of distributed generation. Moreover, although existing housing may face a higher installation cost (and perhaps a more difficult financing ability) there is a much larger base in which activities can be undertaken.

### **Market Segments**

Many of the proposals relate to segmenting the market into various groups and finding the tails of distributions. This generally relates to splitting the market into “high-potential” and “low-potential” customers and perform the modeling on high-potential customers. The use of an overall average price or an overall average cost in the modeling of distributed generation biases the result away from a small segment that may not be average with respect to this specific activity. Segmenting the market is one of our key objectives in forecasting some of the penetration of distributed generation technologies.

The market segments consist of various groups representing various percentages of the market, each facing various technology characteristics or other market characteristics. Clearly the art is in putting these together in a reasonable fashion. These market segments and who they represent (could include third parties) may be fairly independent or may be related. They may interact with the market for distributed generation by facing different prices, different costs, different interest rates, or they may be segments that are willing to pay higher prices, etc.

## **Competition and the Cost Analysis**

There are two aspects to this. The first aspect is that the various distributed generation technologies in the preliminary model do not compete against each other. Since their penetration is so low this may not matter too much, but in a technical sense, they should compete against each other and against purchased electricity. This could be added to the model, but it should probably be accompanied by a change to the financial analysis/cost algorithm. This is the second aspect to this. In the current model, the penetration of each distributed generation technology is based upon an independent payback period analysis that uses the payback period with an assumed penetration rate. This could be replaced with an annualized cost/present discounted value framework that would put all the technologies and the cost of purchased electricity on a level playing field so they could be competed against each other. This would also require an assumed distribution for the estimation of market shares.

## **Miscellaneous**

These would include a variety of policy levers into the model for incentives and subsidies or other motivations including non-economic factors that might impact upon the technology competition and penetration of distributed generation. This also includes looking for overlaps or double counting for distributed generation in the NEMS models. This also includes bringing in the correct price to be used for various purposes from the electricity model.

# Details of Preliminary NEMS Residential Distributed Generation Code

## Background

### Residential Model Introduction

The NEMS Residential Model has a primary level of disaggregation by nine Census divisions and three housing types (single family, multi-family, and mobile homes). The model considers energy consumption for a number of fuels in a wide variety of end uses, within an accounting scheme that takes explicit account of new and replacement capital stock both in housing and in energy-using equipment. The choice algorithms for the energy-using equipment are basically a logit-type formulation, with weights based upon a framework of present discounted value of various costs for competing equipment across general and specific categories of equipment.

Up to and through the Annual Energy Outlook (AEO) 1999, the NEMS residential model has not modeled distributed generation directly. However, some of the energy efficiency modeling might be considered to be a form of distributed generation. During 1999, in preparation for the AEO 2000 and other analyses, preliminary work has been done to add a new, technology-based distributed generation modeling routine to the residential model. All the work is preliminary and is in a testing stage and has not yet been finalized at the time this report is being written. Most of the information that is provided here has been shared with us by the NEMS modelers, but may have changed by the time this is read<sup>4</sup>.

### Distributed Generation Modeling Background

The preliminary residential sector distributed generation algorithm has the potential to evaluate the three technologies of photovoltaics, fuel cells, and micro turbines. The input file represents all three of these technologies. However, micro turbines are in effect turned off (they have a 0 base capacity and a 0 number of hours of operation). Therefore, the algorithm (at this preliminary stage) relates primarily to photovoltaics and fuel cells.

The penetration of each technology is modeled in two separate categories consisting of exogenous penetration and endogenous penetration. The exogenous penetration consists of a fixed exogenous number of installations that is in an input file and is subsequently read in and directly implemented. The endogenous penetration is the subject of the model algorithm and its calculation is dependant upon a variety of variables including prices, costs, consumptions, and various parameters.

The algorithm and most inputs for both exogenous and endogenous penetration are detailed by census division and run year by year starting in 1998. The exogenous penetration amounts are numbers that could apply to any housing types, new or existing. The endogenous penetration is calculated as a rate (a fraction) and is applied to new single family homes only. Each technology is specified and used in the code over five “vintages” to represent its change over time. For example, the first vintage for

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<sup>4</sup>This information is from communications with the NEMS buildings sectors modelers and from a Buildings Sector Working Group Meeting on June 24, 1999. As noted, the work described here is preliminary and may change as further work is done.

photovoltaics covers the period 1993 through 1999 during which it is assumed that photovoltaics have an efficiency of 0.11 and a capital cost of \$6569. The second vintage for photovoltaics covers the period 2000 through 2006 during which it is assumed they have a better efficiency of 0.14 and a lower capital cost of \$5887.

The endogenous penetration algorithm operates year by year using three basic steps. In the first step, the model initializes a variety of variables such as the annual base Kwh output, and the annual base value of electricity saved. In the second step, the model does the financial calculations that determine the payback period for each technology, using a variety of price, cost, load, and economic data. In the third step the model determines the penetration rate for each of the technologies (based upon the payback period), applies it to the number of new single family homes, adds in exogenous penetration numbers and provides the results back to the model.

Table 4 shows the values for the various variables that are in the input file.

### **Initialization of Variables**

In each year, for each census division, and for each of three technologies, a variety of initial values are set up for later use.

*Price of the Distributed Generation, PriceDisGen.* The distributed generation price is the model electricity price. (The original code multiplied this by a net meter adjustment, in other words  $PriceDisGen = ElecPrice * NetMeterAdj$ . For photovoltaics this adjustment was 1.0, for the other technologies it was 0.5. However, later in the code the net meter adjustment was again applied and this electricity price was used where the net meter adjustment was not to be applied. We assumed this was a mistake so have changed it to what is shown below)

$$PriceDisGen = ElecPrice .$$

*Maintenance Cost in the Base Year, MaintCostBase.* The base maintenance cost is the maintenance cost times the Kw capacity.

$$MaintCostBase = MaintCst * SystemKw .$$

*Overall Equipment Cost in the Base Year, EqCost.* The equipment cost is the capital cost plus installation cost times the Kw capacity.

$$EqCost = ( CapCost + InstCost ) * SystemKw .$$

**Table 4. Key Technology Inputs to Residential Distributed Generation**  
 (These are examples from a very preliminary distributed generation input file.)

Penetration Function Parameters

0.7 0.3

	Tech1	Tech2	Tech3
System kw	2.75	7.0	0.0
Annual Oper Hrs	0.	8000.	000.

Net Meter Adjusts by Census Division

Tech1	Tech2	Tech3
1.	.5	.5

Solar Insolation Values

136. New England, Boston  
 137. Middle Atlantic, New York  
 138. East North Central, Detroit  
 172. West North Central, Omaha  
 196. South Atlantic, Miami  
 161. East South Central, Birmingham  
 180. West South Central, Dallas  
 235. Mountain, Albuquerque  
 168. Pacific, Great Falls

Combined Federal and State Tax Rate, DownPayPct, Interest Rate, Loan Years, Inflation

.34 .10 .07 20. .03

Type	Fuel Type	First Year	Last Year	Eff	Loss Factor	Degrad. Factor	Life	Recv Eff	Install Cost	Equip. Cost	Maint Cost	Tax Credit		
												Avail	Percent	Maximum
'Solar_PV'	0	1993	1999	.11	.80	.01	20	0.	500.	6569.	0.	1.	.000	000.
'Solar_PV'	0	2000	2006	.14	.80	.01	20	0.	393.	5887.	0.	1.	.000	000.
'Solar_PV'	0	2007	2009	.16	.80	.01	20	0.	344.	5251.	0.	1.	.000	000.
'Solar_PV'	0	2010	2014	.18	.80	.01	20	0.	306.	4625.	0.	1.	.000	000.
'Solar_PV'	0	2015	2020	.20	.80	.01	20	0.	275.	4004.	0.	1.	.000	000.
'Fuel_Cell'	3	1993	1999	.40	.94	0.	20	.66	125.	5000.	15.	.95	0.	0.
'Fuel_Cell'	3	2000	2004	.40	.94	0.	20	.66	125.	5000.	15.	.95	0.	0.
'Fuel_Cell'	3	2005	2009	.40	.94	0.	20	.66	125.	3000.	15.	.95	0.	0.
'Fuel_Cell'	3	2010	2014	.40	.94	0.	20	.66	125.	2300.	15.	.95	0.	0.
'Fuel_Cell'	3	2015	2020	.40	.94	0.	20	.66	125.	1600.	15.	.95	0.	0.
'Micro_Tur'	3	1993	1999	.240	.94	0.	20	.66	125.	9700.	15.	.95	0.	0.
'Micro_Tur'	3	2000	2004	.240	.94	0.	20	.66	125.	9700.	15.	.95	0.	0.
'Micro_Tur'	3	2005	2009	.240	.94	0.	20	.66	125.	9700.	15.	.95	0.	0.
'Micro_Tur'	3	2010	2014	.240	.94	0.	20	.66	125.	9700.	15.	.95	0.	0.
'Micro_Tur'	3	2015	2020	.240	.94	0.	20	.66	125.	9700.	15.	.95	0.	0.

*Annual Base Kwh Supplied by the Base Sized Equipment, AnnualKWh.* The annual consumption is calculated separately for photovoltaics from the other technologies. For photovoltaics it is the equipment efficiency times the amount of insolation times the loss factor times a measure of the square feet of solar panel. (The square feet of solar panel is given in the equation by the expression “SystemKw \* (346.78 \* 0.18 / Efficiency ) \* 5.0”.) Note that the efficiency drops out of the equation, that it is “embedded” in the relationship between the cost and the square feet of solar panel.

$$\text{AnnualKWh} = \text{Efficiency} * \text{Insolation} * \text{Loss factor} * \text{SystemKw} * (346.78 * 0.18 / \text{Efficiency}) / 5.0 .$$

For the other technologies the AnnualKWh is the operating hours times the availability times the loss factor times the Kw capacity.

$$\text{AnnualKWh} = \text{OperHours} * \text{Avail} * \text{Loss factor} * \text{SystemKw} .$$

*ExcessKwh.* This measures how much electricity is generated by the technology versus how much electricity is typically used in the average house. If less is generated, the excess kwh is negative. Note that the amount of electricity used in the average house (the unit energy consumption or UEC) does not vary by year or region and is a very round value of 10,000 (it is not endogenous).

$$\text{Excess kwh} = \text{AnnualKwh} - \text{ElecAvgUEC}$$

$$\text{where the ElecAvgUEC} = 10000 .$$

*Value of Electricity Saved in the Base Year, ValESaveBase.* This is the value of the amount of electricity that is not otherwise purchased, plus the value of any electricity that is sold back to the grid. Electricity that is sold back to the grid is not necessarily sold at the full retail price. The factor NetMeterAdj adjusts the electricity price so that for photovoltaics the full retail price is used for sales, but for other technologies the price for sales is 0.5 times the retail price.

If Excess kwh <= 0 then

$$\text{ValESaveBase} = \text{AnnualKwh} * \text{PriceDisGen} * 0.003412$$

If Excess kwh > 0 then

$$\text{ValESaveBase} = (\text{Excess kwh} * \text{NetMeterAdj} + \text{ElecAvgUEC}) * \text{PriceDisGen} * 0.003412$$

where Excess kwh and PriceDisGen are defined above.

*Fuel Related Variables.* The following variables have to do with the fuel that is consumed or displaced by fuel cells and/or mini turbines. These do not apply to photovoltaics, in which case these variables are set to zero.

*Gas Input Btu, GasInput.* This is the amount of gas used to fuel the technology.

$$\text{GasInput} = \text{SystemKw} / \text{Efficiency} * \text{OperHours} * \text{Avail} * 0.003412 .$$

*Waste Heat Btu, BtuWasteHeat.* This is the amount of waste heat generated by the technology that could be used for water heating which in turn would displace some energy consumed for water heating.

$$\text{BtuWasteHeat} = (\text{GasInput} - 0.003412 * \text{AnnualKwh}) * \text{WHRecovery} .$$

*Water Heating Unit Energy Consumption, WaterHeatGMMBtu.* This is the amount of the average UEC for gas water heating that can be displaced by the BtuWasteHeat. In all years and in all divisions, this is initially set equal to the average gas water heat UEC which this algorithm sets at 25 (it is not endogenous). Then if the BtuWasteHeat is less than this value it becomes equal to BtuWasteHeat.

$$\text{If BtuWasteHeat} < \text{WaterHeatGMMBtu then WaterHeatGMMBtu} = \text{BtuWasteHeat} .$$

*Fuel Cost in the Base year, BaseYrFuelCost.* This is the net cost of the fuel used to run the technology.

$$\text{BaseYrFuelCost} = (\text{GasInput} - \text{WaterHeatGMMBtu}) * \text{GasPrice} .$$

### **Endogenous Penetration Financial Calculations**

The financial calculations are made by simulating the payments and interest and taxes, etc., year after year (in a Fortran do-loop) over a period of time such as 30 years. This makes it simple to add in or take out various incentives or other things in various periods. It also makes the sequence of calculations transparent to the user. A variety of things are set up ahead of time and then the simulation is run. At the end of the simulation the payback period for this technology is calculated.

*Simulation Setup in the First Year.* A variety of things are initially set up. These include the down payment on the loan (*Downpay*), the annual payment amount (*Payment*), the loan balance (*LoanBal*), tax credit (*TaxCredit*), etc.

$$\text{Downpay} = \text{DownPayPct} * \text{EqCost}$$

$$\text{Payment} = \text{IntRate} / ( 1 - ( 1 + \text{IntRate} )^{(-\text{Term})} ) * ( \text{EqCost} - \text{DownPay} )$$

$$\text{Outlay} = \text{DownPayPct} * \text{EqCost}$$

$$\text{FuelCost} = 0$$

$$\text{MaintCost} = 0$$

$$\text{LoanBal} = \text{EqCost} * ( 1 - \text{DownPayPct} )$$

$$\text{TaxCredit} = 0$$

$$\text{NetCashFlow} = - \text{Outlay}$$

$$\text{CumNetFlow} = -\text{Outlay}$$

*Simulation for Years 2 through 30.* The loan term is given by “Term” and it is typically equal to 20 years. The calculations are made over a longer period of time. In addition to those noted above, some other things calculated include the loan principal (*Prin*), the amount of interest paid (*IntAmt*), the tax deduction for this equipment (*TaxDeduct*), the fuel cost (*FuelCost*), the maintenance cost (*MaintCost*), the value of energy saved (*ValESave*), the net cash flow (*NetCashFlow*), and the net cumulative case flow (*CumNetFlow*).

$$\begin{aligned} \text{In year} = 2: & \quad \text{TaxCredit}(y=2) = 0 \\ \text{In year} = 3: & \quad \text{TaxCredit}(y=3) = \min ( \text{EqCost} * \text{TaxCreditPct}, \text{TaxCreditMax} ) \end{aligned}$$

$$\text{In years} \leq \text{Term}+1: \quad \text{Outlay} = \text{Payment}$$

$$\text{IntAmt} = \text{LoanBal}(y-1) * \text{IntRate}$$

$$\text{In years} \leq \text{Term}+1: \quad \text{Prin} = \text{Payment} - \text{IntAmt}$$

$$\text{LoanBal} = \text{LoanBal}(y-1) - \text{Prin}$$

$$\text{TaxDeduct} = \text{TaxRate} * ( \text{IntAmt}(y-1) + \text{Depr}(y-1) ) + \text{TaxCredit}$$

$$\begin{aligned} \text{In year} = 2: & \quad \text{FuelCost}(y=2) = \text{BaseYrFuelCost} \\ \text{In years} \leq \text{Term}+1: & \quad \text{FuelCost} = \text{FuelCost}(y=2) * ( 1 + \text{Inflation} )^{(\text{year}-2)} \end{aligned}$$

$$\begin{aligned} \text{In year} = 2: & \quad \text{MaintCost}(y=2) = \text{MaintCostBase} \\ \text{In years} \leq \text{Term}+1: & \quad \text{MaintCost} = \text{MaintCost}(y=2) * ( 1 + \text{Inflation} )^{(\text{year}-2)} \end{aligned}$$

$$\begin{aligned} \text{In years} \leq \text{Term}+1: & \quad \text{ValESave} = \text{ValESavBase} * ( 1 + \text{Inflation} )^{(\text{year}-2)} * \\ & \quad ( 1 - \text{Degradation} )^{(\text{year}-2)} \end{aligned}$$

$$\text{In years} \leq \text{Term}+1: \quad \text{Kwh} = \text{AnnualKwh} * ( 1 - \text{Degradation} )^{(\text{year}-2)}$$

$$\text{NetCashFlow} = \text{TaxDeduct} + \text{ValESave} - \text{Outlay} - \text{FuelCost} - \text{MaintCost}$$

$$\text{CumNetFlow} = \text{CumNetFlow}(y-1) + \text{NetCashFlow}$$

The cumulative net cash flow, *CumNetFlow*, is investigated in each year in order to determine the payback period. The payback period (*SimplePayback*) is the number of years until *CumNetFlow* becomes a positive amount (and stays positive for 3 years).

$$\text{SimplePayback} = \text{Number of years until } \text{CumNetFlow} > 0 .$$

The manner in which this financial model works is shown in Table 5, using examples of a variety of the variables above. Table 2 shows a sample set of financial calculations simulated over a 30-year period for photovoltaic technology in the forecast year 2000 using typical values from the input files. It is clear from the table that the cost of the photovoltaic technology so exceeds the resulting value of energy savings that there is never a period in which it is paid back. In this case the payback period is 30 years or more and the consequence is that there is only a very tiny penetration.

**Table 5. Example of Typical Financial Calculations for Residential Photovoltaics**

Simulation Year	Tax Credit	Outlay	Interest Amount	Principal	Loan Balance	Tax Deduction	Fuel Cost	Maintenance Cost	Value of Energy Save	Net Cash Flow	Cumulative Net Flow	Kwh Generation
1	0.00	1727.00	0.00	0.00	15543.00	0.00	0.00	0.00	0.00	-1727.00	-1727.00	0.00
2	0.00	1467.15	1088.01	379.14	15163.86	0.00	0.00	0.00	385.00	-1082.15	-2809.15	4871.90
3	0.00	1467.15	1061.47	405.68	14758.18	369.92	0.00	0.00	392.58	-704.64	-3513.79	4823.18
4	0.00	1467.15	1033.07	434.08	14324.11	360.90	0.00	0.00	400.32	-705.93	-4219.72	4774.95
5	0.00	1467.15	1002.69	464.46	13859.64	351.24	0.00	0.00	408.20	-707.70	-4927.42	4727.20
6	0.00	1467.15	970.18	496.97	13362.67	340.91	0.00	0.00	416.25	-709.99	-5637.41	4679.93
7	0.00	1467.15	935.39	531.76	12830.91	329.86	0.00	0.00	424.45	-712.84	-6350.25	4633.13
8	0.00	1467.15	898.16	568.99	12261.92	318.03	0.00	0.00	432.81	-716.31	-7066.56	4586.80
9	0.00	1467.15	858.33	608.81	11653.11	305.38	0.00	0.00	441.33	-720.44	-7787.00	4540.93
10	0.00	1467.15	815.72	651.43	11001.67	291.83	0.00	0.00	450.03	-725.29	-8512.29	4495.52
11	0.00	1467.15	770.12	697.03	10304.64	277.34	0.00	0.00	458.89	-730.91	-9243.20	4450.56
12	0.00	1467.15	721.32	745.82	9558.82	261.84	0.00	0.00	467.93	-737.38	-9980.58	4406.06
13	0.00	1467.15	669.12	798.03	8760.79	245.25	0.00	0.00	477.15	-744.75	-10725.32	4362.00
14	0.00	1467.15	613.26	853.89	7906.89	227.50	0.00	0.00	486.55	-753.10	-11478.42	4318.38
15	0.00	1467.15	553.48	913.67	6993.23	208.51	0.00	0.00	496.14	-762.50	-12240.92	4275.19
16	0.00	1467.15	489.53	977.62	6015.60	188.18	0.00	0.00	505.91	-773.05	-13013.98	4232.44
17	0.00	1467.15	421.09	1046.06	4969.54	166.44	0.00	0.00	515.88	-784.83	-13798.81	4190.12
18	0.00	1467.15	347.87	1119.28	3850.26	143.17	0.00	0.00	526.04	-797.94	-14596.75	4148.22
19	0.00	1467.15	269.52	1197.63	2652.63	118.28	0.00	0.00	536.40	-812.47	-15409.22	4106.73
20	0.00	1467.15	185.68	1281.46	1371.17	91.64	0.00	0.00	546.97	-828.54	-16237.76	4065.67
21	0.00	1467.15	95.98	1371.17	-0.00	63.13	0.00	0.00	557.75	-846.27	-17084.03	4025.01
22	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
23	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
24	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
25	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
26	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
27	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
28	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
29	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00
30	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-17084.03	0.00

Note: This is a example table created in a spreadsheet, using approximate data and does not directly represent a specific exercise.

## Technology Penetration and Final Results

*Technology Penetration.* The technology penetration is calculated based upon the payback period in two steps. First, the maximum permitted penetration (*MaxPen*) for the technology is calculated as an inverse function of the size of the payback period calculated above along with an input parameter.

$$\text{MaxPen} = \text{PenParm} / \text{SimplePayback}$$

The value for PenParm that is input is 0.3, so if the payback period were 6 years the maximum permitted penetration rate would be 0.05. Shorter payback periods allow a larger maximum penetration rate and longer payback periods allow a smaller maximum penetration rate.

In each forecast year, the actual penetration rate (*Pen*) is a function of the maximum penetration rate and the total number of years since 1998 minus the payback period. The value for the coefficient *alpha* in the input file is 0.7.

$$\text{Pen} = \text{MaxPen} - 1 / ( ( 1 / \text{MaxPen} ) + \exp( \text{alpha} * ( \text{years since 1998} - \text{simplepayback} ) ) ) .$$

As the model forecast year becomes further out, the actual resulting penetration becomes greater. The relationship between the actual penetration and the number of years since 1998 is shown in Table 6. Table 6 shows a sample set of resulting penetration rates for different forecast years and for different payback periods. Obviously, the larger the payback period in the same forecast year, the smaller the maximum and actual penetration. The further out the forecast year, the greater is the resulting penetration for the same payback period.

**Table 6. Examples of Penetration Rates for Different Years and Payback Periods**

Current Year	2010	2010		2015	2015
Years Past 1998	12	12		17	17
Payback Period	8	2		8	2
Penetration Parameter	0.3	0.3		0.3	0.3
Maximum Penetration	0.0375	0.1500		0.0375	0.1500
Alpha Coefficient	0.7	0.7		0.7	0.7
Actual Penetration	0.0143	0.1491		0.0357	0.1500

Note: This is an example table and does not directly represent a specific exercise.

*Number of Endogenous Units.* The endogenous penetration rate is applied to the number of new single family homes in each forecast year and cumulated.

$$\text{AnnUnitsEndo} = \text{Pen} * \text{HseAdd}$$

*Number of Exogenous Units.* The model also accounts for a number of units for each technology that are exogenously input into the model from an input file. These are given as cumulative amounts in each year

for each census division in the input file so that the number of exogenous units added in any given year is equal to:

$$\text{AnnUnitsExog} = \text{ExogPen}(y) - \text{ExogPen}(y-1)$$

*Total Units.* This is the sum of the endogenous and exogenous units.

$$\text{AnnUnits} = \text{AnnUnitsEndo} + \text{AnnUnitsExog}$$

*Cumulative Units.* The sum of the annual units over time.

$$\text{Units}(y) = \text{Units}(y-1) + \text{AnnUnits}$$

*Cumulative Electricity Generation.* The sum over time of the number of housing units times the average consumption per unit.

$$\text{Trills}(y) = \text{Trills}(y-1) + \text{AnnUnits} * \text{AnnualKwh} * 3412 / 10^{12}$$

*Cumulative Own Use.* All electricity generated up to the average unit energy consumption is for own use. Anything above this amount is sold to the grid.

If  $\text{AnnualKwh} > \text{ElecAvgUEC}$  then

$$\text{TrillsOwnUse}(y) = \text{TrillsOwnUse}(y-1) + \text{AnnUnits} * \text{ElecAvgUEC} * 3412 / 10^{12}$$

Else if  $\text{AnnualKwh} \leq \text{ElecAvgUEC}$  then

$$\text{TrillsOwnUse}(y) = \text{TrillsOwnUse}(y-1) + \text{AnnUnits} * \text{AnnualKwh} * 3412 / 10^{12}$$

*Cumulative Gas Usage.* The amount of gas consumed by the technology.

$$\text{GasUsage}(y) = \text{GasUsage}(y-1) + \text{AnnUnits} * \text{GasInput} / 10^6$$

*Cumulative Water Heating Btus.* The amount of water heating Btus that are displaced by the technology.

$$\text{WBtu}(y) = \text{WBtu}(y-1) + \text{AnnUnits} * \text{WaterHeatGMMBtu} / 10^6$$

*Annual Capital Investment Costs.* Total capital cost of the technology in each year.

$$\text{Invest} = \text{AnnUnits} * \text{CapCost} * \text{Kw} / 10^6$$

### **Additional Comments**

Table 7 shows some summarized results from a run of the distributed generation algorithm in the residential model using the AEO99 base case. Virtually all of the penetration for distributed generation comes from the exogenous penetration and virtually none of the penetration come from the endogenous model calculations.

The algorithm is in a very preliminary stage, so these are comments relating only to this version. As noted above the base capacity and the number of hours of operation for micro turbines are 0, in effect turning them off so they are not being modeled. As it turns out, the economics in a typical base case for both photovoltaics and fuel cells are such that the endogenous penetration algorithm does not allow any penetration for them. (Basically the capital costs are too high for them to experience any penetration, especially for fuel cells.) However, photovoltaics do have exogenous penetration, so that the ultimate forecast for photovoltaics comes solely from the exogenous penetration. Fuel cells do not have an exogenous penetration (other than a nominal amount of 1 per region), so that the ultimate forecast for fuel cells is zero.

**Table 7. Overall National Results of a Distributed Generation Model Run (Preliminary)**

(These results are from a standalone AEO99 residential model run using the very preliminary distributed generation routine and input file.)

	1998	2000	2010	2020
Houses added, SF	1.238	1.149	1.196	1.190
New after 1990, SF	5.756	8.022	19.145	30.036
Existing from 1990, SF	65.352	64.778	61.984	59.310
Total Houses, SF	71.108	72.800	81.129	89.346
Total Houses All Types	102.613	105.013	117.480	130.014
Photovoltaics				
Tech Costs	19439.8	17270.0	13560.3	11767.3
Tech Average Kwh	4863.9	4871.9	4824.8	4836.6
Tech Savings Value	393.8	385.0	368.4	341.3
PayBack Years	29.0	29.0	29.0	29.0
Tech Penetration	.000	.000	.000	.000
Endog-This Year	.000	.000	.000	.001
Exog-This Year	8.115	7.813	11.341	.000
Total-This Year	8.115	7.813	11.341	.001
Endog-Cumulative	.000	.000	.000	.002
Exog-Cumulative	8.115	23.637	120.419	120.419
Total-Cumulative	8.115	23.637	120.419	120.420
Fuel Cells				
Tech Costs	35875.0	35875.0	16975.0	12075.0
Tech Average Kwh	50008.0	50008.0	50008.0	50008.0
Tech Savings Value	1228.8	1196.8	1148.5	1061.8
PayBack Years	29.0	29.0	29.0	29.0
Tech Penetration	.000	.000	.000	.000
Endog-This Year	.000	.000	.000	.001
Exog-This Year	.000	.009	.000	.000
Total-This Year	.000	.009	.000	.001
Endog-Cumulative	.000	.000	.000	.002
Exog-Cumulative	.000	.009	.009	.009
Total-Cumulative	.000	.009	.009	.011

### Commercial Model Input and Code Differences

The preliminary commercial model code uses a very similar approach (including similar variable names and similar inputs) for modeling distributed generation. For this reason we are concentrating on the residential sector in the expectation that the residential enhancements can easily be extended to the commercial sector. With that in mind some of the key differences between the preliminary distributed generation code between residential and commercial include the following.

## **Commercial Sector Input File**

The commercial sector includes a bigger slate of distributed generation technologies than the residential sector. The seven technologies includes the three in the residential, solar PV, fuel cells, and micro turbines, but then adds some conventional technologies including, conventional gas, coal, oil, and MSW. The conventional technologies are included particularly because the commercial sector has historical consumption for cogeneration using conventional fuels. The capacities, costs, and other characteristics for the commercial model technologies are different from those in the residential sector.

The input file also contains a matrix of sharing fractions that is used to allocate the generation of each technology to the various commercial sector building types.

## **Commercial Sector Model Code**

The commercial sector distributed generation model operation is very similar to that of the residential distributed generation model, except for the fact that the commercial sector starts with an historical level of cogeneration that must be accounted for in the model. The model reads in this historical cogeneration fuel consumption and using the characteristics of the model technologies does an initialization in which it converts the consumptions to penetrations of conventional technologies (in terms of number of units or buildings). This is then saved as the initial value for the number of units for conventional technologies.

At this point in the code, the commercial distributed generation model operates almost exactly the same as the residential one, including sharing most of the same variable names. It calculates a variety of cost and energy values for each technology in turn, uses them in a payback period analysis, and then calculates a penetration rate for the technology.

The penetration rate is used to calculate the number of units (buildings) of each technology and these are cumulated over time. However, in the case of conventional technologies, the number of historical units (due to cogeneration as explained above) are added in during the first year.

The effect of the distributed generation equipment on various model variables such as electricity own use, electricity sales, consumption of gas, and others is calculated. Finally, the commercial model fills a number of variables that are passed to the electricity model with values such as grid sales by fuel type, own use, cogeneration consumption, and cogeneration capacity. The residential model does not have corresponding variables.

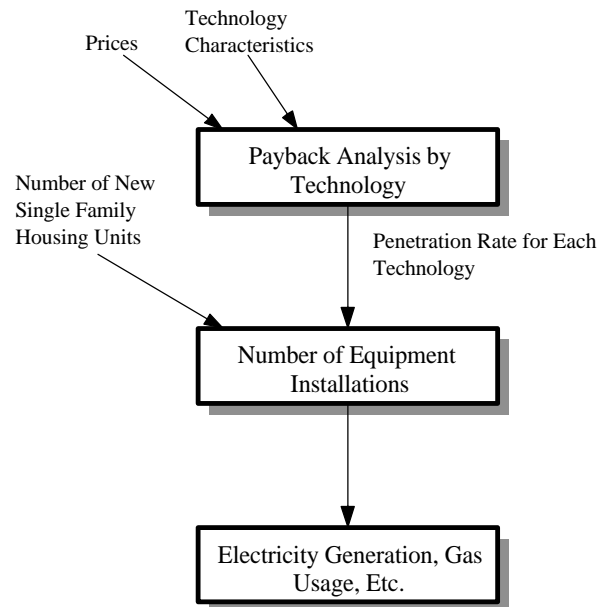
## Model Changes Including Code and Inputs

As discussed earlier, the emphasis here in making changes to the model code and to the inputs is directed towards the building models and in particular to the residential sector distributed generation code. The preliminary NEMS code for distributed generation in the residential and commercial sectors is very similar so the changes are concentrated on just one of them. Among the various changes, there are three key, substantial model changes:

- C The model was expanded for full housing coverage which includes new and existing housing and housing types.
- C The market for distributed generation was divided into market segments, each with a percentage of the market and with its own set of financial, cost, and/or price characteristics.
- C An alternative methodology was created to compete the various annualized technology costs against each other and against the cost of purchased electricity, using a distribution on those costs to determine market shares. This substitutes for the payback period and penetration rate analysis.

The basic operation of the original preliminary NEMS distributed generation model is summarized in Figure 1.

**Figure 1. Preliminary NEMS Distributed Generation Model**



### Reference Case Forecast

The reference case for the distributed generation work comes from an AEO99 version of the NEMS

residential model that runs standalone on the PC. It uses the same code and input files as the version running on the RISC machine and produces the same output. This version has the distributed generation code added to it along with additional input files and various new reports.

Table 8 shows residential sector consumption by fuel type for various forecast years for a case in which there is no distributed generation. Table 9 shows the same consumption for the distributed generation reference case. The reference case is the preliminary version of the distributed generation model and input file that we were originally given. We incorporated this version of the distributed generation model into the AEO99 residential model code. Table 10 shows the number of housing units for the distributed generation reference case by housing type and vintage type for various forecast years at a national level. Note that the distributed generation routine has no impact on housing units, so this is also the housing unit table for the no distributed generation case and all of the subsequent distributed generation cases. Table 11 shows the reference case results for distributed generation. It can be seen from the table that there is virtually no endogenous penetration of distributed generation, the only penetration comes from the exogenous penetration in the input file.

**Table 8. Residential Consumption by Year for National**  
(No Distributed Generation)

	1995	2000	2005	2010	2015	2020
Electricity	3557.0	4009.9	4312.2	4588.3	4946.1	5324.0
Natural Gas	4984.4	5209.8	5309.3	5518.0	5775.4	5938.2
Coal	53.5	56.7	54.1	51.8	50.5	49.3
Distillate	882.5	869.1	785.1	731.1	690.5	653.1
Kerosene	74.3	74.9	71.0	69.2	67.6	66.5
Liquid Gas	404.3	440.6	437.9	431.8	419.0	404.7
Petroleum Total	1361.1	1384.6	1294.0	1232.0	1177.1	1124.2
Biomass	586.5	602.8	610.2	622.0	636.3	650.6
Delivered Energy	10542.5	11263.8	11579.7	12012.2	12585.4	13086.4

**Table 9. Residential Consumption by Year for National**  
(Distributed Generation Reference Case)

	1995	2000	2005	2010	2015	2020
Electricity	3557.0	4009.5	4311.1	4586.3	4944.0	5321.7
Natural Gas	4984.4	5209.8	5309.3	5518.0	5775.4	5938.2
Coal	53.5	56.7	54.1	51.8	50.5	49.3
Distillate	882.5	869.1	785.1	731.1	690.5	653.1
Kerosene	74.3	74.9	71.0	69.2	67.6	66.5
Liquid Gas	404.2	440.6	437.9	431.8	419.0	404.7
Petroleum Total	1361.1	1384.6	1294.0	1232.0	1177.1	1124.2
Biomass	586.5	602.8	610.2	622.0	636.3	650.6
Delivered Energy	10542.5	11263.4	11578.6	12010.2	12583.3	13084.1

**Table 10. Housing Report at a National Level**

	2000	2005	2010	2015	2020
Single Family					
Housing Units Added	1.149	1.171	1.196	1.192	1.190
New After 1990	8.022	13.524	19.145	24.662	30.036
Existing From 1990	64.778	63.366	61.984	60.632	59.310
Total Housing Units	72.800	76.890	81.129	85.294	89.346
Multi-Family					
Housing Units Added	.353	.402	.490	.451	.419
New After 1990	2.187	4.021	6.216	8.413	10.356
Existing From 1990	23.511	22.998	22.496	22.006	21.526
Total Housing Units	25.697	27.019	28.713	30.418	31.882
Mobile Homes					
Housing Units Added	.338	.356	.384	.400	.411
New After 1990	2.171	3.417	4.597	5.690	6.656
Existing From 1990	4.344	3.635	3.042	2.546	2.130
Total Housing Units	6.516	7.053	7.639	8.236	8.787
Overall Total					
Housing Units Added	1.840	1.930	2.071	2.043	2.020
New After 1990	12.380	20.962	29.957	38.765	47.048
Existing From 1990	92.633	89.999	87.522	85.184	82.966
Total Housing Units	105.013	110.961	117.480	123.949	130.014

**Table 11. Distributed Generation Report at a National Level**

	2000	2005	2010	2015	2020
Photovoltaics					
Tech Costs	11603.8	11603.8	9108.7	7913.4	7913.4
Tech Average Kwh	4871.9	4840.7	4824.8	4831.5	4836.6
Tech Savings Value	385.0	376.3	368.4	354.2	341.3
PayBack Years	29.0	29.0	28.1	26.9	27.9
Tech Penetration	.000000	.000000	.000032	.001649	.001664
Endog-This Year	.0000	.0000	.0386	1.9657	1.9793
Exog-This Year	7.8130	9.2509	11.3406	.0000	.0000
Total-This Year	7.8130	9.2509	11.3792	1.9657	1.9793
Endog-Cumulative	.0000	.0000	.0386	2.2115	12.0770
Exog-Cumulative	23.6368	66.9440	120.4186	120.4186	120.4186
Total-Cumulative	23.6368	66.9440	120.4572	122.6301	132.4956
Fuel Cells					
Tech Costs	23625.0	14525.0	11340.0	8155.0	8155.0
Tech Average Kwh	50008.0	50008.0	50008.0	50008.0	50008.0
Tech Savings Value	1196.8	1169.9	1148.5	1103.5	1061.8
PayBack Years	29.0	29.0	29.0	29.0	29.0
Tech Penetration	.000000	.000000	.000000	.000000	.000001
Endog-This Year	.0000	.0000	.0000	.0000	.0009
Exog-This Year	.0090	.0000	.0000	.0000	.0000
Total-This Year	.0090	.0000	.0000	.0000	.0009
Endog-Cumulative	.0000	.0000	.0000	.0001	.0019
Exog-Cumulative	.0090	.0090	.0090	.0090	.0090
Total-Cumulative	.0090	.0090	.0090	.0091	.0109

### Housekeeping

A variety of changes were made to the residential model distributed generation code with respect to housekeeping. These are not changes that change the underlying structure of the code or change the results. These include:

*New Summary Output Report.* A new summary report was written for the distributed generation routine. The only previous report was a large set of debug writes that was big and diffuse and was not particularly useful for understanding what was happening in the model. The new report summarizes a

variety of the results for each technology for each region over 5-year intervals. The report is also customizable using variables in the input file. It can be turned on and off and can write various regions, various years, and various technologies.

*Include File for Model Variables.* The model variable declarations were put into an include file and system parameters were substituted for a number of the variable dimensions.

*Reorganization of Some Code.* Some of the existing code was reorganized and some was rewritten. In both cases the results were the same. Changes were also made to the code including spacing and alignment of statements, and addition of or changes to a number of comments.

*Adding Variables to the Input File.* A variety of variables that were hardwired in the code or which would be useful for run control were added to the input file.

### **Full Housing Coverage**

The current preliminary version of the distributed generation model in NEMS calculates a penetration only in newly added single family housing units. There is additional opportunity for a good deal of penetration into new multi-family housing units and especially into already existing housing units. As can be seen in Table 10 the residential model has three housing types and uses a vintage-type accounting scheme. We have extended the distributed generation model to cover all housing types and both new and existing housing vintages. This has required a variety of assumptions that have been added to the input file. The incorporation of these additional levels of detail were done in conjunction with adding market segments, which is described in the next section. The model operation and the effect on the results is discussed in the next section.

*Housing Types.* Clearly, most of the distributed generation technologies can penetrate into single family housing units. They can also penetrate into multi-family housing units, but generally not by individual housing units but as part of a larger project. This could be a project for an entire building, or for an entire development of buildings. Penetration into mobile homes is less certain. In our revised distributed generation model we calculate a separate penetration rate for single family and multi-family housing units. Mobile homes use the single family penetration rate. Figuratively, this is shown as:

$$DGHousingType1 = DGPenetrationRate1 * ( SFHousingUnits + MHHousingUnits ) \text{ and}$$

$$DGHousingType2 = DGPenetrationRate2 * MFHousingUnits .$$

*Housing Vintage.* There is a large potential for distributed generation in existing housing, if only because the stock of existing housing is so much larger than that for newly added housing. In our version we calculate a separate penetration rate for new housing and for existing housing. First we need to define what we mean by each of these. The residential model uses a vintage-type accounting scheme in which it keeps track of three “vintages” of housing units for each forecast year. First, there are those housing units that were in existence in the initial model year, 1990, and are still in existence in the current forecast year. Second, there is the cumulative sum of those housing units that have been added in each forecast year since 1990. Third, there are those housing units that are newly added in just the current forecast year. (Those newly added in the current year are already included in the cumulative sum of the added housing units.) The total housing stock is the sum of existing housing units remaining from 1990

and units added since 1990. These are shown in Table 10. Note that remaining housing from 1990 is retired so that the total decreases over time.

Distributed generation is potentially added beginning in 1998. We calculate a separate penetration rate for new housing units and for existing housing remaining from 1998. It is necessary to implement the penetration rate differently for new and for existing housing units. Beginning in 1998 the current model calculates a penetration rate for new housing units in each forecast year and determines the number of units with distributed generation. In any one forecast year, the total amount of units with distributed generation is the sum of all those units in each year since 1998. We continue to use this, but need to do a few different things for existing housing remaining from 1998.

In each forecast year we now calculate a separate penetration rate for existing housing units remaining from 1998. This penetration rate applies not just to existing housing units remaining from 1990 but also to those that have been built from 1990 till the year before 1998. Figuratively, this is shown as:

$$DG_{Existing1998} = DGPenetrationRate_{Existing} * ( HU_{Existing1990} + HU_{New1990to1997} ) .$$

Moreover, the distributed generation calculated above for the remaining housing stock in 1998, is a stock number, not a flow number. This is the opposite of that calculated for new. In other words, the result gives the total amount of distributed generation in the stock, not just that for one year. In order to calculate the amount of distributed generation added in one forecast year in the remaining housing stock in 1998, it is necessary to subtract the amount in the previous year.

$$NewDG_{Existing2005} = DG_{Existing2005} - DG_{Existing2004} .$$

The existing penetration rate applies to a stock of housing units and determines a stock of distributed generation equipment. For this reason, we have added a ratchet effect to the calculation so that the stock of distributed generation equipment cannot decline from one year to the next. We assume that once the equipment is put into place it will not be removed the next year. For the same reason, we have created a ramp for the penetration of distributed generation in the existing stock. Since the model begins in 1998, it is not practical that the entire stock of existing housing would be eligible immediately. We use a ramp that makes a fraction of the existing stock available from .01 to 1.0 from the years 2000 to 2020.

A couple of implicit assumptions are made for this algorithm. The first is that there are no retirements of distributed generation equipment during the forecast horizon. The second is that there are no retirements during the forecast horizon in the housing stock that was new between 1990 and 1998.

### **Market Segments**

As described earlier, one of the key objectives is to segment the market into smaller groups that face different electricity prices, or face different technology characteristics. The use of an overall average price or an overall average cost in the modeling of distributed generation biases the result away from a small segment that may not be average with respect to a specific characteristic. With a technology such as distributed generation, it is necessary to find that market segment that does not face average circumstances in order to see any penetration.

The market segments consist of various groups representing various percentages of the market, each

facing alternative technology characteristics or other market characteristics. For example, 10 percent of the market might have a technology cost that is only 60 percent of the average cost, perhaps because they are part of a large project that has significant cost advantages. Clearly there is an art to constructing all of this information in a reasonable fashion. We had to make a variety of assumptions to put this together, but our assumptions may be better than simply using an across-the-board average.

The market can be segmented over a variety of activities, each with consequences that impact upon the penetration of distributed generation. The three primary ones considered here are “financing ability”, project size, and electricity price structure. The first two are implemented together, because there is a good deal of relatedness between them.

### **“Financing Ability” Market Segments**

Financing ability is a catchall phrase used here to designate the relative ability of various segments of the market to finance a distributed generation investment. This could impact upon the model in a variety of ways having to do with the interest rate for a loan, the availability of capital, the amount of risk and the ability to pool it, the term of the loan, etc. Addressing all of these would increase the complexity of the model beyond a reasonable amount. We concentrate on the interest rate which is probably the most important of these variables and one that can also be considered a proxy for the others. We have segmented the market into those that have easy financing (a low interest rate), those that have average financing (the average interest rate), and those that have difficult financing (a high interest rate). The model will be run for each of these three segments and each segment will represent a proportion of the market. This is explained in more detail below.

### **Project Size Market Segments**

Project size is another catchall phrase used here to designate the overall size of the project. This does not necessarily mean the size of the equipment, but rather the size of the investment and the number of housing units involved. Large projects might involve distributed generation investments by whole neighborhoods or communities, or by large multi-family buildings or groups of buildings. This might also involve projects by third parties. This impacts upon distributed generation effectiveness, primarily through the equipment capital cost and/or the installation cost. It also probably impacts upon the financing ability and interest rate with large projects having more favorable financing. There are probably many other things that impact, but as above, addressing all of them would increase the complexity of the model beyond a reasonable amount. We have segmented the market into small projects (using the average capital cost of equipment and installation) and large projects (using a lower capital cost of equipment and installation). The model will be run for each of these two segments and each segment will represent a proportion of the market. This is explained in more detail below.

### **Model Implementation for Financing Ability and Project Size Market Segments**

The financing ability and project size market segments are interrelated so we implemented them into the model together. At the same time, we implemented the model changes for the accounting of full housing coverage which includes the three housing types and the new and existing vintages of housing. (These were discussed in more detail above.)

The process is relatively straightforward. The market is divided into several independent segments, each of which represents a certain percentage of the total market. Then, in the modeling, each of these market

segments faces a different set of characteristics relating to prices or costs or other variables.

In this case we are assuming that the market segments consist of small and large projects overlaid on easy, average, and difficult financing. This gives us six segments, illustrated below:

	Easy Financing	Average Financing	Difficult Financing
Small Projects	LowRate/AvgCost	AvgRate/AvgCost	HghRate/AvgCost
Large Projects	LowRate/LowCost	AvgRate/LowCost	HghRate/LowCost

To help keep things in hand we made the assumption that only four of these market segments are really relevant (two of them probably represent extremely small market segments so are eliminated from our list). Each of the four remaining market segments represents a share of the market, such as in:

	New Housing		Existing Housing	
	SF	MF	SF	MF
Low Rate / Large Project (Low Cost)	0.20	0.50	0.20	0.50
Average Rate / Small Project (Average Cost)	0.50	0.20	0.50	0.20
Average Rate / Large Project (Low Cost)	0.20	0.20	0.20	0.20
High Rate / Small Project (Average Cost)	0.10	0.10	0.10	0.10

Each of these market segments represents a share of the market in different housing types and in different housing vintages. The shares in single family houses may be quite different than those in multi-family housing as shown above. For example, as shown in the table above, only 20 percent of single family housing units consider distributed generation projects as part of large projects that have low interest rates and low costs, while 50 percent of multi-family housing units do.

In this particular set of market segments we are implementing three variable changes in the model. These are interest rates, equipment capital cost, and equipment installation cost. A new variable for each of these provides a set of factors for each market segment relative to the base characteristic in the input file. For example, one of the market segments might have an equipment cost factor of 0.8. If the base equipment cost in the technology file is \$6,000 then for this particular market segment a cost of  $\$6,000 * 0.8 = \$4,800$  is used. In the model implementation the market shares and characteristics are allowed to change over time. The input file has values for the years 2000, 2010, and 2020. The model uses the year 2000 values in 1998 and 1999 and interpolates for the other values. A preliminary input file that is being used for testing is given as an example in Table 12.

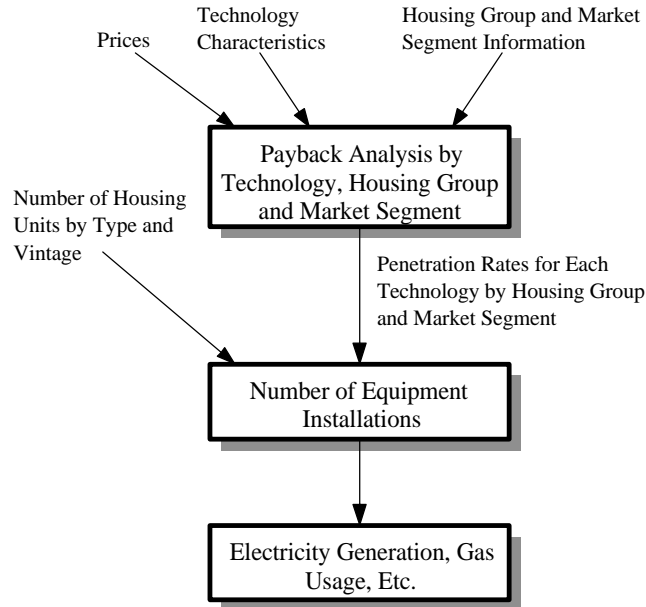
The model then performs the financial analysis, consisting of setting up all the variables, calculating the payback period, and determining the penetration rate, for each of the market segments for single family and multi-family housing in new and existing housing. (This consists of 16 separate determinations where the model previously did one.) Using the market shares for each market segment, an overall penetration rate is determined for each of the housing types and vintages. These penetration rates are then implemented against the relevant housing units for each housing type and vintage to determine the number of housing units installing distributed generation.

**Table 12. Financial/Project Market Segment Inputs**

Market Shares in New Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.20	0.25	0.30	0.50	0.55	0.60
AvgRate/SmallProject	0.50	0.45	0.40	0.20	0.15	0.10
AvgRate/LargeProject	0.20	0.25	0.30	0.20	0.25	0.30
HghRate/SmallProject	0.10	0.05	0.00	0.10	0.05	0.00
Market Shares in Existing Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.20	0.25	0.30	0.50	0.55	0.60
AvgRate/SmallProject	0.50	0.45	0.40	0.20	0.15	0.10
AvgRate/LargeProject	0.20	0.25	0.30	0.20	0.25	0.30
HghRate/SmallProject	0.10	0.05	0.00	0.10	0.05	0.00
Interest Rate Factor in New Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.75	0.62	0.50	0.75	0.62	0.50
AvgRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
AvgRate/LargeProject	1.00	1.00	1.00	1.00	1.00	1.00
HghRate/SmallProject	1.33	1.67	2.00	1.33	1.67	2.00
Interest Rate Factor in Existing Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.75	0.62	0.50	0.75	0.62	0.50
AvgRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
AvgRate/LargeProject	1.00	1.00	1.00	1.00	1.00	1.00
HghRate/SmallProject	1.33	1.67	2.00	1.33	1.67	2.00
Equipment Cost Factor in New Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.60	0.50	0.40	0.60	0.50	0.40
AvgRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
AvgRate/LargeProject	0.60	0.50	0.40	0.60	0.50	0.40
HghRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
Equipment Cost Factor in Existing Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.60	0.50	0.40	0.60	0.50	0.40
AvgRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
AvgRate/LargeProject	0.60	0.50	0.40	0.60	0.50	0.40
HghRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
Installation Cost Factor in New Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.60	0.50	0.40	0.60	0.50	0.40
AvgRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
AvgRate/LargeProject	0.60	0.50	0.40	0.60	0.50	0.40
HghRate/SmallProject	1.00	1.00	1.00	1.00	1.00	1.00
Installation Cost Factor in Existing Buildings						
	---Single Family---			---Multi-Family---		
	2000	2010	2020	2000	2010	2020
LowRate/LargeProject	0.80	0.70	0.60	0.80	0.70	0.60
AvgRate/SmallProject	1.50	1.40	1.30	1.50	1.40	1.30
AvgRate/LargeProject	0.80	0.70	0.60	0.80	0.70	0.60
HghRate/SmallProject	1.50	1.40	1.30	1.50	1.40	1.30

The basic operation of this revised distributed generation model that adds housing groups and market segments is summarized in Figure 2. This can be compared to the basic operation of the original model shown in Figure 1.

**Figure 2. Addition of Housing Groups and Market Segments**



The model results using the above input file are shown in Table 13. The table shows some mechanical results of the new algorithm, using inputs that are reasoned guesses. The inputs may be a little optimistic, but should be reasonable, although they were chosen primarily to show how the algorithm works. The table is organized into the four categories of single family/new housing, multi-family/new housing, single family/existing housing, and multi-family/existing housing. Results are shown in each of these housing categories, along with the full detail and weighted average for the penetration rates for each of the market segments. Note that in some market segments there is now a significant amount of endogenously calculated distributed generation penetration. The model previously based everything on the average interest rates and average costs and as a consequence the model had no endogenous penetration of distributed generation.

**Table 13. Distributed Generation Report for National**

	2000	2005	2010	2015	2020
Solar Photovoltaic					
Single Family/New Housing					
Average Energy Use (Kwh)	4881.0	4870.4	6438.0	5837.6	5421.7
Value of Energy Savings	382.8	376.9	508.3	433.7	389.0
Technology Costs	14506.8	13772.8	10170.2	8207.7	7531.0
Years for Payback	29.0	29.0	18.4	17.0	15.8
LowR/BigP Penetration	.00000	.00000	.03788	.06020	.05868
AvgR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
AvgR/BigP Penetration	.00000	.00000	.00702	.03476	.04086
HghR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
Overall Penetration Rate	.00000	.00000	.01123	.02612	.02986
Current Year Units	.000	.000	1.790	18.362	32.850
Cumulative Units	.000	.000	1.873	35.364	170.371
Multi-Family/New Housing					
Average Energy Use (Kwh)	4866.7	4849.2	6440.8	5852.1	5418.0
Value of Energy Savings	380.6	374.3	508.6	435.0	388.4
Technology Costs	12434.4	11441.4	8136.2	6266.1	5412.9
Years for Payback	29.0	29.0	11.5	10.0	8.9

LowR/BigP Penetration	.00000	.00000	.03798	.06037	.05799
AvgR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
AvgR/BigP Penetration	.00000	.00000	.00704	.03486	.04024
HghR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
Overall Penetration Rate	.00000	.00000	.02265	.04430	.04687
Current Year Units	.000	.000	1.225	9.251	13.962
Cumulative Units	.000	.000	1.286	19.108	79.793
Single Family/Existing Housing					
Average Energy Use (Kwh)	4630.4	4629.2	6448.6	5297.9	5042.4
Value of Energy Savings	370.9	361.1	509.3	399.2	366.4
Technology Costs	14917.5	14137.6	10422.6	8410.0	7712.5
Years for Payback	29.0	29.0	18.8	18.9	17.1
LowR/BigP Penetration	.00000	.00000	.02501	.04046	.05127
AvgR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
AvgR/BigP Penetration	.00000	.00000	.00324	.01967	.02936
HghR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
Overall Penetration Rate	.00000	.00000	.00706	.01653	.02419
Current Year Units	.000	.000	15.412	295.462	145.584
Cumulative Units	.000	.000	15.767	390.709	1082.019
Multi-Family/Existing Housing					
Average Energy Use (Kwh)	4472.6	4473.0	6447.8	4974.8	4798.2
Value of Energy Savings	373.1	357.9	509.2	383.5	358.2
Technology Costs	12747.8	11725.1	8338.1	6434.3	5571.7
Years for Payback	29.0	29.0	12.2	13.4	10.5
LowR/BigP Penetration	.00000	.00000	.02499	.03626	.04865
AvgR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
AvgR/BigP Penetration	.00000	.00000	.00323	.01389	.02684
HghR/SmlP Penetration	.00000	.00000	.00000	.00000	.00000
Overall Penetration Rate	.00000	.00000	.01455	.02467	.03724
Current Year Units	.000	.000	8.136	197.548	76.018
Cumulative Units	.000	.000	8.338	244.397	621.933
Current Year					
Endogenous Penetration	.000	.000	26.562	520.623	268.413
Exogenous Penetration	7.813	9.251	11.341	.000	.000
Total Penetration	7.813	9.251	37.902	520.623	268.413
Cumulative					
Endogenous Penetration	.000	.000	27.263	689.578	1954.115
Exogenous Penetration	23.637	66.944	120.419	120.419	120.419
Total Penetration	23.637	66.944	147.682	809.997	2074.534

The impact of this distributed generation activity on consumption is shown in Table 14. The consumption can be compared to that in Table 5. In the year 2020, the consumption of purchased electricity is down by 35.4 trillion Btu.

**Table 14. Residential Consumption by Year for National**

	1995	2000	2005	2010	2015	2020
Electricity	3557.0	4009.5	4311.1	4585.7	4931.8	5288.6
Natural Gas	4984.4	5209.8	5309.3	5518.0	5775.4	5938.3
Coal	53.5	56.7	54.1	51.8	50.5	49.3
Distillate	882.5	869.1	785.1	731.1	690.5	653.1
Kerosene	74.3	74.9	71.0	69.2	67.6	66.5
Liquid Gas	404.2	440.6	437.9	431.8	419.0	404.7
Petroleum Total	1361.1	1384.6	1294.0	1232.0	1177.1	1124.2
Biomass	586.5	602.8	610.2	622.0	636.3	650.6
Delivered Energy	10542.5	11263.4	11578.6	12009.6	12571.1	13051.0

In this particular analysis, there were four market segments. In the examples, the market shares for these four segments add up to 1.0. This is not necessary. If these added up to 0.9 it would imply that 10 percent of the market does not fall in any of these categories and in essence is not being modeled. In addition, the market segments can easily be extended to cover additional segments if desired. This would

require a change to the input file (and potentially to a parameter that provides the dimensioning for the variables).

### **Electricity Price Market Segments**

Another key segmentation of the market relates to the electricity prices that may be faced by different market segments. The question about electricity prices and the various circumstances that could influence them is a more complex subject area. Another variable is available in the market segment methodology to change the electricity prices (or not change them) for each of market segments. For example, a new market segment might be defined as a “off-the-grid” segment consisting of a small percentage of consumers who must pay a very high electricity price, basically forcing them to choose among the distributed generation technologies. The complexities begin to enter when we consider the consequences of higher electricity prices by time-of-day or due to unbundling of transmission and distribution costs. This might not be addressed easily by using market segments.

Time-of-day pricing is likely in future competitive electricity markets, but in any event this segment faces higher prices for only a few hours of the day. As discussed below, this temporal aspect to prices might be enough to pay for equipment, depending upon the height and duration of the peak price. Unbundling of transmission and distribution costs by customer may occur in the future, which would lead to higher electricity prices for a certain segment of customers. Electricity distributors face higher costs for these same customers in this market segment. So the distributors might invest in distributed generation themselves, or might be willing to pay the customers an incentive to invest in distributed generation. After the unbundling the customers might have an incentive to invest in distributed generation directly due to higher prices. In any event, this should tie into the electricity model and the shape of the MDCC curve, as discussed below.

### **Competition and the Cost Analysis**

The earlier discussion noted that there are two areas in the current payback period methodology that could be done differently. The first area of methodology has to do with the fact that the various distributed generation technologies in the preliminary model do not compete against each other or against the price of purchased electricity. If the penetration rate for any of the technologies were to be significant, their interdependence might be of real concern. The other area of that could be done differently is the payback period analysis that is used for the penetration rate algorithm. An alternative methodology would be to use a levelized cost algorithm that would compete the technologies against each other's total annualized cost and against the cost of purchased electricity. The costs would be used as (inverse) weights in a distribution to get technology shares. This has been done in an alternative version of the distributed generation model.

### **Description of the Alternative Model Cost Algorithm**

A version of the distributed generation model has been created that replaces the payback period algorithm with an annualized cost algorithm that competes the technologies against each other and against the cost of purchased electricity. This alternative model starts with the same technologies and inputs, and it includes the same enhancements described above relating to the full housing coverage and the market segments. This model calculates the total annualized cost for each technology and uses these and the cost of electricity as weights in a competitive distribution to calculate technology shares. Much of what was calculated for the previous payback period algorithm is no longer needed and is eliminated.

Several new values are calculated. (An example is provided further below.)

*Cost Recovery Factor.* A cost recovery factor is calculated in a discounting equation for the later purpose of annualizing the equipment and installation costs. The factor represents the proportion of the total cost that represents an annual payment that would pay for the full cost over the discounted future. This is given by:

$$CRF = \text{DiscountRate} / ( 1.0 - ( 1.0 + \text{DiscountRate} ) ^ ( -\text{CLife} ) ) .$$

The discount rate is a measure of the interest rate, but also includes premiums for risk and various market imperfections. A new variable has been added to the input file that provides the discount rate premium. The model adds this to the interest rate to get the discount rate. We have chosen to use a discount rate premium of 0.05 for initial testing purposes. (An enhancement would be to vary this premium for the various market segments.)

$$\text{DiscountRate} = \text{InterestRate} + \text{DiscountRatePremium} .$$

The lifetime is not necessarily the lifetime of the equipment, but rather a consumer perceived lifetime for this equipment. This takes into account the time over which the consumer perceives using the equipment and how much time it takes to get their value out of it. This is also a new variable in the input file and we have chosen to use a value of 7 years for initial testing purposes.

*Tax Credit.* A tax credit is implemented in a fashion that effectively reduces the equipment cost. It is assumed that the tax credit is a full credit in the amount of a percentage of the equipment cost up to a maximum level. (An alternative type of tax credit would reduce reported income by the amount of the credit, so only the tax percentage of the credit would be deducted from the equipment cost.) Since the equipment cost in the input file is in terms of dollars per kilowatts of capacity, it is necessary to multiply this cost by the system capacity to get the full cost of the equipment. It is also assumed that the tax credit would not be applied until the second year, so that in the current period it is discounted over two years to get the present value of the tax credit. This is given by:

$$\text{TTax} = ( \text{TaxCreditPercent} * \text{CapCost} * \text{SystemKwh(tech)} ) * ( 1.0 + \text{DiscountRate} ) ^ -2.0 .$$

*Annualized Cost for Equipment and Installation Minus Tax Credit.* The cost for equipment and for installation is in the input file in dollars per kilowatt of capacity. Therefore it is necessary to multiply this equipment cost by the system capacity to get the full cost of the equipment. Each type of equipment has a different installed capacity, also given in the input file. The total cost for the equipment and installation is the cost per kw of capacity times the capacity size of the equipment minus the total tax credit. This is given by:

$$\text{EIC} = ( \text{CapCost} + \text{InstCost} ) * \text{SystemKw(tech)} - \text{TTax} .$$

This is a total cost and it is annualized by multiplying it by the cost recovery factor:

$$\text{AEIC} = \text{EIC} * \text{CRF} .$$

*Annual Maintenance Cost.* The annual maintenance cost is equal to the input maintenance cost per kw of capacity times the capacity size of the equipment given by:

$$AMC = \text{MaintCst} * \text{SystemKw}(\text{tech}) .$$

*Annual Fuel Cost.* For technologies that consume fuels, the annual fuel cost per kwh is equal to the total amount of fuel consumed for generating all the kwh of generation times the price for the fuel. The total cost of fuel consumed was previously calculated for use in the payback period algorithm, and we continue to use this same value. For some equipment, this value takes into account a credit for a reduced level of gas consumption for water heating.

$$AFC = \text{BaseYrFuelCost} .$$

*Total Annualized Technology Cost.* This is the sum of the three annual costs above.

$$ATC = \text{AEIC} + \text{AMC} + \text{AFC} .$$

*Total Annualized Technology Cost per Kilowatthour.* In order to compare the total cost for each technology to other technologies and to the price of electricity, it is necessary to put them on a common plane by putting the costs in terms of dollars per kilowatthours. There is a difficulty to this due to the fact that some of the generation may be sold to the grid. The revenue that is created by the sales to the grid must be subtracted from the total cost. First it must be determined if there are any sales to the grid. A model variable designates the amount of any electricity generation that will be for own use. Any amount after that level will be sold to the grid. This variable is the average unit energy consumption multiplied by a own use factor:

$$\text{DGEAvg} = \text{AvgUEC} * \text{OwnUseFactor}$$

The amount of AvgUEC is calculated endogenously in the model as described under the miscellaneous section, below. The OwnUseFactor is read from the input file and is set to 0.6 for initial model testing purposes.

If the amount of generation, AnnualKwh, is less than DGEAvg then all of AnnualKwh is for own use. If AnnualKwh is greater than DGEAvg then the difference, AnnualKwh - DGEAvg, is the amount of sales. If there are no sales to the grid then the total annualized cost per kilowatthour is given by:

$$\text{ATCKwh} = \text{ATC} / \text{AnnualKwh} .$$

If there are sales to the grid, then it is necessary to subtract out the grid sales revenues before dividing by the amount of own use generation. The revenue is the amount of sales times the price in dollars per kwh. However, the price at which sales are made to the grid is not necessarily at the full retail price of electricity. Depending upon the legislation in effect this net meter price may depend upon the technology and vary anywhere from the generation price of electricity to the full retail price of electricity. This is given by the variable, NetMeterAdj, and is read in from the input file. Currently it is 1.0 for solar PV and 0.5 for other technologies. The annual sales and annual revenues are given by:

$$\text{ASale} = \text{AnnualKwh} - \text{DGEAvg} , \text{ and}$$

$$\text{ARev} = \text{ASale} * \text{EPrice} * 0.003412 * \text{NetMeterAdj} .$$

The revenues are then subtracted from the total cost (leaving just the cost for own use generation) and

then the total cost is divided by the kilowatthours of own use for comparison to other technologies and to the price of electricity.

$$ATCKwh = ( ATC - ARev ) / DGEAvg .$$

*Cost of Purchased Electricity Per Kwh.* The price of electricity is in dollars per million Btu. This is converted to dollars per kilowatthour to provide a common basis for comparison with the technology costs. This electricity price is the full cost of purchasing electricity for consumers, which may not be appropriate for competition purposes. As electricity purchases are reduced, there may still be some fixed costs, such as a hookup cost or a pooled distribution cost, that the consumer is charged. In this case only part of the electricity cost is avoided. We have added a factor to the electricity price that represents the portion of electricity price that can be avoided and this variable has been added to the input file. We have chosen to use an avoided electricity price factor of 0.60 for initial testing purposes.

$$PELKwh = ElecPrice * 0.003412 * AvoidFac .$$

Some further assumptions might improve this value. First, it probably varies by region and over time. Second, it may not be as straightforward as a simple factor on the electricity price, but may be a fixed charge per customer.

*Technology and Purchased Electricity Cost Competition.* A competition is performed among each of the technologies and with the cost of electricity in order to determine the share for each technology. Those technologies with the higher costs receive smaller shares and those with lower costs receive larger shares. An inverse power function is used to determine the weights for each of the technologies and purchased electricity, given by:

$$TechWeight = ATCKwh(tech) ^ (-Lamda) , \text{ and}$$

$$ElecWeight = PELKwh ^ (-Lamda) .$$

A new variable has been added to the input file that provides the equation coefficient, lamda. We have chosen to use a relatively low value of 3.0 for lamda for initial testing purposes.

*Use of the Result In the Model.* Once the shares have been calculated in the alternative algorithm, they are used in the model in the same way that the penetration rates were previously used. The appropriate shares are multiplied times the housing types and new and existing housing vintages to come up with the number of units of each technology that are installed. The rest of the model is the same as before.

*Additional Comments.* A number of comments were made above but a few additional things might be noted about this algorithm.

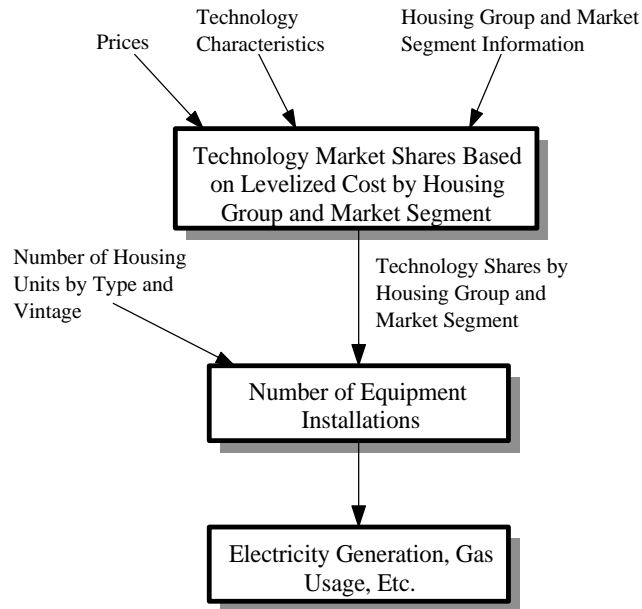
The choice of a share function and the coefficients for the algorithm is difficult, there being little basis on which to make that choice. Unfortunately, the results are very dependent upon these choices. This is also just as true for the choice of a penetration function and the coefficients driving it for the original payback period analysis.

This type of algorithm would be conducive to adding other types of attributes and calculating the shares based upon the idea of consumer utility. We are already doing this with only one attribute, annualized

cost, entering into the utility equation. Although there would be difficulties, we could add other attributes such as reliability or purchased electricity convenience to the algorithm and assign coefficients (weights) to each measure of utility.

The basic operation of this alternative levelized cost distributed generation model, including the previous addition of housing groups and market segments, is summarized in Figure 3. This can be compared to the basic operation of the original model shown in Figure 1 and the revised model as shown in Figure 2.

**Figure 3. Alternative Technology Cost Competition**



### **An Example of the Values in the Equations**

Table 15 shows a number of the intermediate results for an example of the annualized cost competition and share calculation for region 1 (New England) in the year 2020, using the basic set of inputs in the original technology file (applying to single family homes without the large project advantages). The results are representative of all the regions, with the solar PV capturing a very small share, fuel cells capturing a small, but significant share, and the bulk of the share going to purchased electricity.

This example shows the relative advantages of fuel cells versus solar PV. (The current data base does not include real numbers for micro turbines.) Solar PV provides only a very small amount of electricity generation, but has a much higher capital and installation cost. As a consequence its economics are much worse than fuel cells, resulting in a total annualized cost per kilowatt-hour of about 70 cents while fuel cells are only about 24 cents. The avoided cost of purchased electricity comes in at a bit less than 6 cents per kwh, making fuel cells a long-shot competitor with purchased electricity.

**Table 15. Example of the Annualized Cost Competition and Share Calculation**

	Solar PV	Fuel Cell	Micro Turbine	Electricity
Equipment Cost per Kw	4004	1600	9700	--
Installation Cost per Kw	275	125	125	--
Capacity Size in Kw	2.75	7.00	--	--
Annualized Total E & I Cost	2578	2646	--	--
Maintenance Cost	0	105	--	--
Gas Consumption	--	429	--	--
Gas Price	--	6.97	--	--
Fuel Cost	0	2990	--	--
Annual Generation in kwh	3735	50008	--	--
Own Use of Generation	3735	18300	--	--
Revenue from Grid Sales	0.0	1459	--	--
Total Annual Cost	2578	4282	--	--
Annualized Cost per kwh	0.690	0.234	99.0	--
Electricity Cost per kwh	--	--	--	0.055
Resulting Technology Shares	0.001	0.013	0.000	0.987

**Comparative Model Results with the Alternative Methodology**

As noted above, in the alternative competition methodology, the economics for fuel cells become sufficiently favorable to achieve a significant penetration. The data and assumptions that are input to the model will still need to be reviewed and there may be some additional considerations with respect to the methodology. Table 16 shows the residential model results for fuel cells and Table 17 shows the overall residential consumption. The end result is a significant penetration of fuel cells that have a relatively large generation capacity. As a consequence there is a moderate amount of electricity generation (a considerable portion which is for own use, with a little more than half sold to the grid), with a considerable increment in natural gas consumption consumed in the fuel cells.

**Table 16. Distributed Generation with Alternative Competitive Methodology**

	2000	2005	2010	2015	2020
Fuel Cell					
Single Family/New Housing					
Average Energy Use (Kwh)	50008.0	50008.0	50008.0	50008.0	50008.0
LowR/BigP Penetration	.0054	.0191	.0321	.0528	.0513
AvgR/SmlP Penetration	.0017	.0060	.0095	.0161	.0137
AvgR/BigP Penetration	.0054	.0191	.0321	.0528	.0513

HghR/SmlP Penetration	.0017	.0060	.0095	.0161	.0137
Overall Penetration Rate	.0032	.0119	.0208	.0363	.0363
Current Year Units	4.17	15.76	29.00	52.61	53.10
Cumulative Units	12.91	48.25	144.69	317.98	579.67
Multi-Family/New Housing					
Average Energy Use (Kwh)	50008.0	50008.0	50008.0	50008.0	50008.0
LowR/BigP Penetration	.0052	.0186	.0312	.0515	.0500
AvgR/SmlP Penetration	.0016	.0058	.0091	.0155	.0132
AvgR/BigP Penetration	.0052	.0186	.0312	.0515	.0500
HghR/SmlP Penetration	.0016	.0058	.0091	.0155	.0132
Overall Penetration Rate	.0041	.0154	.0268	.0461	.0464
Current Year Units	1.25	5.24	11.34	18.62	17.45
Cumulative Units	3.66	15.26	51.48	115.81	203.87
Single Family/Existing Housing					
Average Energy Use (Kwh)	50008.0	50008.0	50008.0	50008.0	50008.0
LowR/BigP Penetration	.0051	.0179	.0291	.0472	.0459
AvgR/SmlP Penetration	.0016	.0055	.0084	.0142	.0122
AvgR/BigP Penetration	.0051	.0179	.0291	.0472	.0459
HghR/SmlP Penetration	.0016	.0055	.0084	.0142	.0122
Overall Penetration Rate	.0030	.0110	.0188	.0324	.0324
Current Year Units	.01	120.78	255.12	660.70	77.63
Cumulative Units	2.04	169.22	579.95	1515.01	1973.17
Multi-Family/Existing Housing					
Average Energy Use (Kwh)	50008.0	50008.0	50008.0	50008.0	50008.0
LowR/BigP Penetration	.0046	.0158	.0262	.0437	.0429
AvgR/SmlP Penetration	.0014	.0048	.0076	.0131	.0114
AvgR/BigP Penetration	.0046	.0158	.0262	.0437	.0429
HghR/SmlP Penetration	.0014	.0048	.0076	.0131	.0114
Overall Penetration Rate	.0036	.0130	.0225	.0391	.0397
Current Year Units	.01	45.95	99.57	259.43	33.80
Cumulative Units	.82	65.21	228.58	612.08	810.84
Overall Current Year Penetration					
Endogenous	5.44	187.73	395.02	991.37	181.98
Exogenous	.01	.00	.00	.00	.00
Total	5.44	187.73	395.02	991.37	181.98
Overall Cumulative Penetration					
Endogenous	19.43	297.94	1004.70	2560.87	3567.55
Exogenous	.01	.01	.01	.01	.01
Total	19.44	297.95	1004.71	2560.88	3567.56
Electricity (TBtu)	3.32	50.84	171.43	436.96	608.72
Electricity Own Use (TBtu)	1.62	25.28	84.10	210.44	292.11

**Table 17. Residential Consumption with Alternative Competitive Methodology**

	1995	2000	2005	2010	2015	2020
Electricity	3557.0	4007.8	4285.3	4500.4	4728.8	5021.3
Natural Gas	4984.4	5218.6	5444.5	5974.0	6937.5	7557.2
Coal	53.5	56.7	54.1	51.8	50.5	49.3
Distillate	882.5	869.1	785.1	731.1	690.5	653.1
Kerosene	74.3	74.9	71.0	69.2	67.6	66.5
Liquid Gas	404.2	440.6	437.9	431.8	419.0	404.7
Petroleum Total	1361.1	1384.6	1294.0	1232.0	1177.1	1124.2
Biomass	586.5	602.8	610.2	622.0	636.3	650.6
Delivered Energy	10542.5	11270.5	11688.1	12380.2	13530.2	14402.7

### Miscellaneous

#### Average Electricity Unit Energy Consumption

In the original model there is a variable that is used to determine the level of electricity generation for the

average household that separates electricity for own use from electricity sold to the grid. Any electricity generation below that amount is for own use and any generation above that amount is sold to the grid. The variable is called the average electricity unit energy consumption, *ElecAvgUEC*, and it is set to the exogenous value of 10,000 (10 million Btu). The level of this variable also affects the value of energy savings variable in the model.

This value should vary depending upon the household's average unit energy consumption. A variable was added to the model to calculate the average electricity unit energy consumption endogenously from the model results. The variable used, *rsflcn*, has detail by census region, but not by housing type because the model's consumption is not calculated and retained by housing type. (This could be added, but with considerable effort.) Since the consumption is a final result of the model in any one year and the distributed generation routine feeds into that final result, it is necessary to use the previous year's value for consumption. This is divided by the number of housing units to get unit energy consumption.

This value is the actual unit energy consumption, which is considerably larger than the level separating own use consumption from that sold to the grid. This is an average value over many households and in general it attempts to explain that on average there would be a mix between generation and purchase of electricity. One reason might be that there is a load shape to demand versus the flat level of distributed generation supply. It is assumed that a fraction of this unit energy consumption would be satisfied by own use generation and any generation over that amount would be sold to the grid. This fraction that is own use is in the input file and is currently set to be 0.6.

### **Equipment Kilowatts of Capacity**

Each type of distributed generation equipment is sized according to a kilowatt capacity, which is the variable *SystemKw*, and is in the input file. This variable is used to determine the total amount of generation or costs, but equipment costs do not vary by capacity. As a consequence this variable does not have any effect upon the equipment penetration, but does have an impact upon the total amount of generation. Changing this variable will increase or decrease the amount of forecasted distributed generation proportionally. The annual generation for solar PV equipment of the capacity size in the model is only about a third or a quarter of the average household's energy use. On the other hand, the capacity size for fuel cells generates about three times the average household's energy use. Of course, there are technical limits to these capacity sizes, but these capacities should have some kind of endogenous consequence to the model, and perhaps be sized by the model. This may be particularly true for certain market segments (for example, with large projects).

### **Net Meter Price Adjustment**

The price at which sales are made to the grid is not necessarily the electricity retail price. It may be a price that reflects only the generation or wholesale price, not including the transmission and distribution costs. The model currently has a variable, *NetMeterAdj*, which addresses this concern. (We made a correction to an error in the use of this variable which is described in the model detail section.) The variable is a factor that is applied to the retail electricity price to get an approximation to the price for sales to the grid. The value is 1.0 for solar PVs and 0.5 for fuel cells and micro turbines. It is apparently assumed in the preliminary model that net meter legislation for PVs causes their sales to be sold at the retail price level. There are limits to this legislation and it varies greatly, so this assumption should probably be revisited.

The value for this price can be improved by directly using the wholesale price that is calculated in the electricity model in a full NEMS or POEMS run.

## **Further Work**

### **Testing and Scenarios (Next Subtask)**

The next step is to make the final adjustments to the model operation and to the input file values and execute a variety of test scenarios. This is the subject of the next subtask in this project. The example runs that have been made here are for initial testing purposes, only, and are done with parameters that are generally developed more to show the effects than as good final numbers. The runs that have been made here are also run in a standalone PC version of the residential model and do not benefit from the feedback from the rest of the modeling system such as in NEMS or POEMS. In most cases this would make little difference. However, if there is a considerable change in the amount of generation or electricity purchases or in the amount of natural gas consumption, the feedback effects could be significant.

### **Topics for Further Improvements**

A number of issues have been discussed previously, but there are some that cannot be addressed in the context of this task, but are important for future consideration.

*Additional Distributed Generation Technologies.* Additional technologies might be added to the input file, particularly a variety of more conventional technologies.

*Additional Technology Attributes for Competition Algorithm.* Technologies and purchased electricity compete on a variety of levels or attributes, not just on cost. Some of these may be intangible, but they can be added to the competition algorithm with a variety of assumptions. These should also differ by market segment so that each segment enters the competition with different attributes. For example, there might be a “green power” attribute for solar PVs that would apply to a small market segment.

*Time-of-day Pricing.* Time-of-day pricing will be a common aspect to a future competitive electricity market. Prices may be high enough, even during brief periods of time, that they pay for the cost of distributed generation equipment. During at least part of the non-peak period, as long as variable costs are covered, the equipment could continue to produce additional revenue. The full consequence of this should be represented in the model.

*Tie-In to the Electricity Model Distribution Costs.* The original proposal for the electricity model was to estimate the marginal distribution capacity cost (MDCC) and use this to determine a level of investment in distributed generation to relieve the high costs of some distribution (and transmission). The investment in distributed generation would be made by generators (or distributors).

Some accounting should be made by the amount of distributed generation made in the demand sectors with the idea of using this to flatten out the MDCC curve. In addition, some of the investment in distributed generation (due to the MDCC) might also be made by end users or by third parties for end users. This might be encouraged in the model by the electricity model providing equipment cost subsidies to the demand sectors.