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THE EFFECT OF DISTRIBUTED ENERGY RESOURCE COMPETITION WITH CENTRAL GENERATION

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ACRONYMS

AEO	Annual Energy Outlook
CC	Combined Cycle
CHP	Combined Heat and Power
CT	Combustion Turbine
DER	Distributed Energy Resource
EIA	Energy Information Administration
EPA	Environmental Protection Agency
GWh	GigaWatt-hour = 1,000 MWh
LDC	Load Duration Curve
MWh	MegaWatt-hour
mmBtu	million British thermal units
O&M	Operations and Maintenance
PJM	Pennsylvania, New Jersey, Maryland Interconnection LLC
ST	Steam Turbine
STEO	Short Term Energy Outlook
TWh	TeraWatt-hour = 1,000 GWh

EXECUTIVE SUMMARY

Distributed Energy Resource (DER) has been touted as a clean and efficient way to generate electricity at end-use sites, potentially allowing the exhaust heat to be put to good use as well. However, despite its environmental acceptability compared to many other types of generation, it has faced some disapproval because it may displace other, cleaner generation technologies. The end result could be more pollution than if the DER were not deployed. However, the DER may actually be competing against older power plants instead. If the DER is built then these other plants may be retired sooner, reducing their emissions. Or it may be that DER does not directly compete against either new or old plant capacity at the decision-maker level, and increased DER simply reduces the amount of time various plants operate.

The key factor is what gets displaced if DER is added. For every kWh made by DER a kWh (or more with losses) of other production is not made. If enough DER is created, some power plants will not get built so not only their production but also their capacity is displaced.

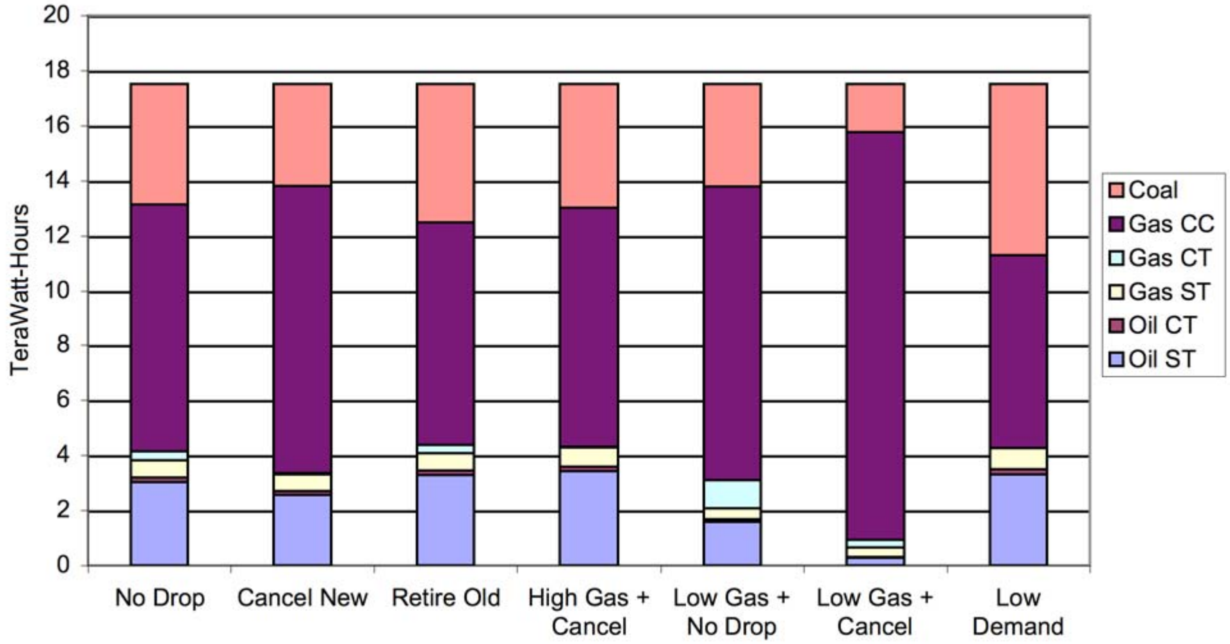
In a previous paper (Hadley et al, 2003) we examined the changes to system operations if we introduce a small amount of DER. We chose to model the Mid-Atlantic Area Council, one of the reliability councils in the North American Electric Reliability Council. We used the Oak Ridge Competitive Electricity Dispatch (ORCED) model to simulate the addition of 100 MW of DER into the region based on 1999 demands. We could then see how other plants changed operations, with a consequent change in energy use and air emissions.

For this study, we examined the changes in an electric system if a relatively large amount of DER (2000 MW) were introduced. Two main DER scenarios were evaluated: DER operating all the time and DER operating only during weekdays. We created three options: 1) there was no other change in the system's capacity, 2) an equivalent amount of new gas-fired combined cycle (CC) capacity was not built, and 3) the oldest and least-economic of existing capacity was retired. We also conducted several sensitivities on changes in fuel prices and over-all level of system reserves.

Note that we did not analyze whether 2000 MW would be built, could be built, or should be built, but rather what is the impact if it is built. From these options, we can see what impact DER has on the system. Does DER displace CC production on a one-for-one basis or are other technologies also affected? What are the net overall emission changes? What influence does fuel price or excess capacity have on the amount and type of capacity displaced? How much does utilization of the exhaust heat in combined heat and power (CHP) applications influence the overall impact? And, given the market as defined in the model, will new or old capacity more likely be affected by the growth of DER?

The results were evaluated in two key ways: which central power plants declined in production due to the addition of the DER, and what was the consequent change in energy use and emissions. While the conventional wisdom is that additions of DER will automatically displace new combined cycle production, we found that that was not totally correct. In the cases with baseload DER, multiple types of production were displaced, even if gas CC capacity was cancelled in response to the DER (Figure ES-1). Only the case with the low gas prices (\$3.25/mmBtu) and cancellation of new capacity shows an overwhelming amount of displacement of CC production with DER. In the others, significant amounts of coal and oil capacity were also displaced.

Figure ES-1. Central generation displaced by DER operating year-round in different scenarios



In the scenarios with DER operating only during weekdays there was a similar pattern, but a higher proportion of displaced generation came from gas CC (Figure ES-2). In the one case with low gas prices and cancelled CC plants, the amount of CC production declined so much (due to cancellation) that other central plants increased their production to make up the deficit. Otherwise, the displacement caused by DER production came from multiple technologies.

Figure ES-2. Central generation displaced by DER operating weekdays only in different scenarios

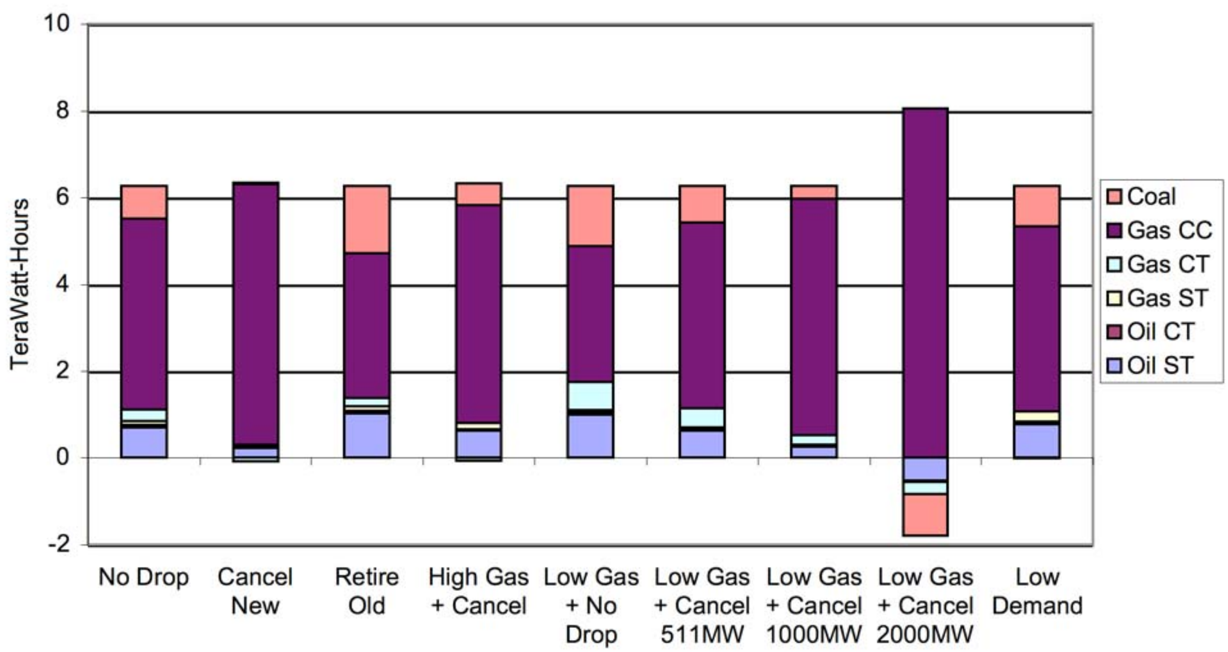


Table ES-1 shows the net primary energy (fuel) and emissions changes from all of the scenarios studied, as a fraction of the fuel used or emissions from the DER. Without CHP, the fuel use and consequent CO_2 emissions from the DER was greater than the displaced central generation so that the net change was positive. But with CHP, the net fuel use and CO_2 releases were less than the combined displaced electric generation plus displaced thermal energy production, so the net ratio is negative. NO_X emissions from DER were very low so that net emissions were negative even with just electricity generation.

Table ES-1. Net changes in energy and emissions as a fraction of the DER's amounts for all scenarios studied. Positive means a net increase and negative means a net savings. NO_X changes are shown as a ratio to the DER emissions. SO_2 changes are "+" or "-" since DER emits no SO_2.

System change	Fuel prices	Demand	DER mode	Primary Energy (fuel) Used		CO_2		NO_X		SO_2	
				No CHP	With CHP	No CHP	With CHP	No CHP	With CHP	No CHP	With CHP
No cancel	Platts (Ref)	2006 +10%	Peak	28%	-32%	14%	-48%	-4x	-17x	-	-
			Base	24%	-38%	24%	-38%	-6x	-19x	-	-
Cancel 2000 new	Platts (Ref)	2006 +10%	Peak	**41%**	**-22%**	**36%**	**-23%**	**+.1x**	**-13x**	**-**	**-**
			Base	27%	-34%	27%	-34%	-5x	-18x	-	-
Retire 2000 old	Platts (Ref)	2006 +10%	Peak	**24%**	**-38%**	**-2%**	**-61%**	**-6x**	**-20x**	-	-
			Base	**22%**	**-39%**	**22%**	**-39%**	**-7x**	**-20x**	-	-
Cancel 2000 new	STEO (High)	2006 +10%	Peak	35%	-27%	23%	-36%	-2x	-15x	-	-
			Base	24%	-38%	24%	-38%	-7x	-19x	-	-
Cancel 2000 new	AEO (Low)	2006 +10%	Peak	**51%**	**-11%**	**64%**	**2%**	**+4x**	**-9x**	**+**	**+**
			Base	36%	-25%	36%	-25%	-2x	-15x	-	-
Cancel 1000 new	AEO (Low)	2006 +10%	Peak	36%	-26%	31%	-31%	-1x	-14x	-	-
Cancel 511 new	AEO (Low)	2006 +10%	Peak	29%	-32%	15%	-46%	-3x	-16x	-	-
No cancel	AEO (Low)	2006 +10%	Peak	23%	-39%	1%	-61%	-6x	-18x	-	-
			Base	28%	-34%	28%	-34%	-5x	-18x	-	-
Cancel 2000 new	Platts (Ref)	2006	Peak	30%	-32%	14%	-48%	-4x	-17x	-	-
			Base	22%	-39%	22%	-39%	-8x	-21x	-	-
Average of all Scenarios				**30%**	**-32%**	**24%**	**-37%**	**-4x**	**-17x**		

Four cases are highlighted. Of the reference cases, the case with peaking DER and cancellation of new CC capacity had the least savings. Without CHP, even NO_X emissions were higher with DER, but with CHP there were savings in all categories. On the other hand, if old plants are retired, then net savings were high. The most damaging scenario to DER was with the peaking scenario, low gas prices, and cancellation of 2000 MW of new CC. The results show a net increase in all categories without CHP and an increase in CO_2 and SO_2 emissions even with CHP. This is likely the scenario that many have assumed when considering the benefits of DER, but only appears with outdated assumptions on gas prices.

Although the scenarios are not equally likely, the average results of all the scenarios show a striking conclusion. Savings were significant across the broad range of scenarios. Even if new, gas-fired CC capacity was cancelled in proportion to the impact of DER on system loads, energy was saved and net emissions reduced. Utilizing the exhaust heat from the DER compounded the savings and made DER a valuable component of the country's energy portfolio.

The Effect of Distributed Energy Resource Competition with Central Generation

1. Introduction

Distributed Energy Resource (DER) has been touted as a clean and efficient way to generate electricity at end-use sites, potentially allowing the exhaust heat to be put to good use as well. However, despite its environmental acceptability compared to many other types of generation, it has faced some disapproval because it may displace other, cleaner generation technologies. The end result could be more pollution than if the DER were not deployed. On the other hand, the DER may be competing against older power plants. If the DER is built then these other plants may be retired sooner, reducing their emissions. Or it may be that DER does not directly compete against either new or old plant capacity at the decision-maker level, and increased DER simply reduces the amount of time various plants operate.

The key factor is what gets displaced if DER is added. For every kWh made by DER a kWh (or more with losses) of other production is not made. If enough DER is created, some power plants will get retired or not get built so not only their production but their capacity is displaced.

Various characteristics of the power system in a region will influence how DER impacts the operation of the grid. The growth in demand in the region may influence whether new plants are postponed or old plants retired. The generation mix, including the fuel types, efficiencies, and emission characteristics of the plants in the region will factor into the overall competition. And public policies such as ease of new construction, emissions regulations, and fuel availability will also come into consideration.

1.1 Power capacity marketplace

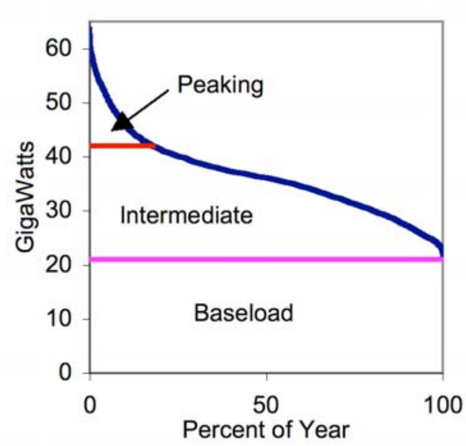
On a day-to-day basis, power plants in a regulated system are called upon to operate based on their incremental operating costs, with some exceptions due to specific requirements of the network. In a wholesale market, bid prices would substitute for incremental operating costs, and some plants with fixed contracts may operate regardless of the wholesale price. Any electricity production from DER will simply mean that demand on the grid is reduced and whichever plant is "on the margin" or the last one called upon to produce will lower their production level.

Besides this day-to-day energy market, there is a longer-term capacity market that gets affected by the DER production. As sales are reduced over a longer period then the growth rate of system power demand is lowered. If new plants are still constructed and old plants continue to be available, then the overall reserve margin will increase. Many of the plants will be called upon for a lower percentage of the year, wholesale prices may be lowered, and a number of the plants will face increased profitability problems.

Power plant owners may respond to the loss of sales in several ways. They may choose to mothball or retire existing plants, postpone or cancel the construction of new plants, or simply face lowered profits (perhaps eventually going bankrupt.) A regulated firm that has multiple plants as well as the distribution system will likely balance its cancellations and retirements depending on the overall economics while independent power producers (IPPs) with a limited portfolio of plants will be more constrained in their decisions. The lack of available capital may dictate cancellations of new plants regardless of their individual economics, just as the boom in plant construction in recent years happened with little consideration of the overall market.

Since demand fluctuates over the year, some plants will be called on more often than others and any power system will have a mix of supply types. Figure 1 shows an example of the load duration curve (LDC) for a region and the types of plants that are used to fulfill those demands. Some plants are most effective at providing power essentially all the time, or "baseload" power. They typically have low variable costs but may have high fixed costs. Their low variable costs translate into low bid prices or marginal costs, while the fixed costs are best paid for spread over a large amount of sales. Intermediate plants are called on to come on a significant fraction of the year but will still cycle on and off. Peaking plants are called on the least frequently, during high demand times or to meet capacity emergencies. They have the highest marginal costs but typically have low fixed costs, either because of their technology or because they are old, fully depreciated plants.

Figure 1. Load Duration Curve and different power plant classes



DER operations may be used in any of these modes, depending on the needs of the end-user and the economics involved. Facilities that have a steady requirement for power (and thermal energy if CHP), such as factories or hospitals, may use DER as baseload power. Facilities that have more fluctuating power needs, such as office buildings, may only use DER during operating hours leading more towards peaking or intermediate use. Finally, some facilities may only use DER as emergency capacity in case of actual shortfalls from the grid or very high prices. They may run their DER infrequently, relying on it as a type of insurance rather than as a significant energy producer. (Oftentimes, emissions regulations only allow a DER to run <200 hours before more extensive regulations come into play.)

If central system capacity (as opposed to just production) is displaced by DER and the capacity would have had significantly different production amounts than the DER, then other system resources besides the cancelled capacity will be affected. If the cancelled capacity was for peaking purposes and the DER ran as baseload, then other plants will have their production lowered as well since the DER generated more power than the cancelled capacity. On the other hand, if the capacity that gets cancelled was baseload and the DER only operated during peak times, then other capacity will have to run at a higher load level to make up the difference. This residual impact on other technologies can have significant ramifications on the net emissions from the DER, as seen below.

Beyond the potential for delaying new capacity, DER may have a more subtle impact on overall energy use. If new capacity is deferred then advances in the technology, through learning-curve advances or simply diverted interest in research, may also be delayed. However, advances in DER technology would be accelerated. These are likely subtle and immeasurable changes, and would require large penetrations of DER to have an impact.

The relative costs to compare DER to the displaced generation are more difficult to compare. While it may be a simple matter to compare the capital and operating costs of central generation to DER, other factors will take precedence for decision-makers. First, as mentioned above, there may be different decision-makers on whether to build DER or central generation, and these decision-makers will have different capital and fuel cost structures. Integrated utilities use a combination of equity and bond-financing backed by the strength of the utility; independent power producers are more likely to use project financing based on the future sales from the power plant; DER owners may fund the project through capital improvements budgets of their over-riding business, competing against other non-energy capital projects.

Fuel costs may be quite different, with large plants purchasing natural gas at wholesale or spot rates while DER owners purchase natural gas at the citygate or commercial rates. On the other hand, central plants may only sell their electricity at wholesale rates while DER owners avoid the purchase of power at higher commercial rates. DER owners using CHP will also be avoiding purchase of fuel for their thermal needs, as well as the capital cost of a separate boiler. All of these factors make it impossible to make blanket statements on the relative cost of DER versus central plants.

1.2 Analytical Framework

In a previous paper (Hadley et al 2003) we examined the changes to system operations if we introduce a small amount of DER. We modelled the Mid-Atlantic Area Council, one of the reliability councils in the North American Electric Reliability Council. It is also known as PJM-East, as the Pennsylvania, New Jersey, Maryland Interconnection LLC (PJM) organization has expanded westward in recent years into other reliability council territories. We used the Oak Ridge Competitive Electricity Dispatch (ORCED) model to simulate the addition of 100 MW of DER into the region based on 1999 demands. We could then see how other plants changed operations, with a consequent change in energy use and air emissions.

For this study, we have examined the changes in an electric system if a relatively large amount of DER (2000 MW) were introduced. Note that we did not analyze whether 2000 MW would be built, could be built, or should be built, but rather what is the impact if it is built. We considered three options for the central system: 1) there were no other change in the system's capacity, 2) an equivalent amount of new gas-fired combined cycle (CC) capacity was not built, and 3) the oldest and least-economic of existing capacity was retired. We also conducted several sensitivities on changes in fuel prices and over-all level of system reserves.

Table 1 shows the set of cases that were examined. Variations were made on the changes to the central system capacity, fuel prices, consumer demand, the amount of production from the DER, and whether the DER's thermal exhaust was used.

Table 1. Scenarios analyzed

System capacity change	Fuel prices	Demand	DER mode	Scenarios Analyzed	
				No CHP	With CHP
No cancel	Platts (Ref)	2006 +10%	Peaking	X	X
			Baseload	X	X
Cancel 2000 new	Platts (Ref)	2006 +10%	Peaking	X	X
			Baseload	X	X
Retire 2000 old	Platts (Ref)	2006 +10%	Peaking	X	X
			Baseload	X	X
Cancel 2000 new	STEO (High)	2006 +10%	Peaking	X	X
			Baseload	X	X
Cancel 2000 new	AEO (Low)	2006 +10%	Peaking	X	X
			Baseload	X	X
Cancel 1000 new	AEO (Low)	2006 +10%	Peaking	X	X
Cancel 511 new	AEO (Low)	2006 +10%	Peaking	X	X
No cancel	AEO (Low)	2006 +10%	Peaking	X	X
			Baseload	X	X
Cancel 2000 new	Platts (Ref)	2006	Peaking	X	X
			Baseload	X	X

From these options, we can see what impact DER has on the system. Does DER displace CC production on a one-for-one basis or are other technologies also affected? What are the net overall emission changes? What influence does fuel price or excess capacity have on the amount and type of capacity displaced? How much does utilization of the exhaust heat in combined heat and power (CHP) applications influence the overall impact? And, given the market as defined in the model, will new or old capacity more likely be affected by the growth of DER?

2. PJM market analysis procedure

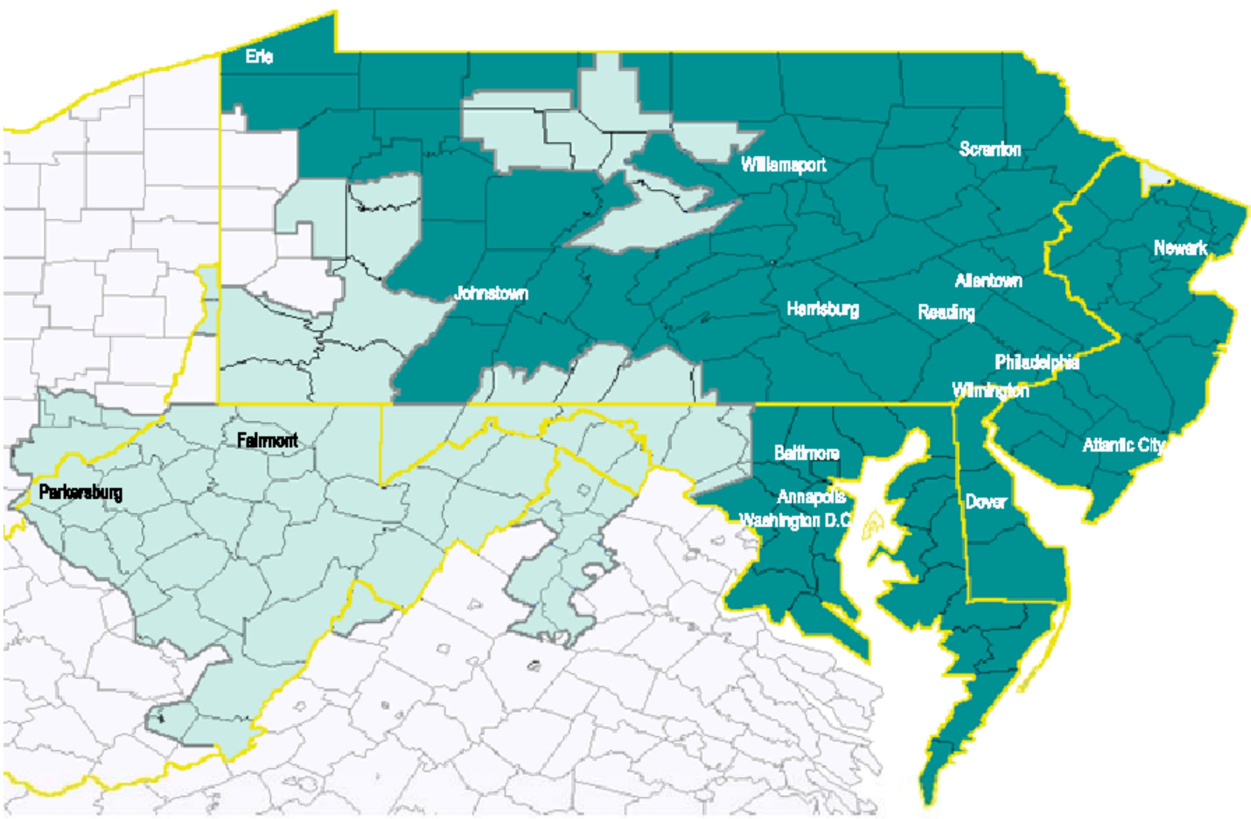
To model the impact of DER on an area's power system we first must collect the data to define the system, both supply and demand. More extensive discussion of the methodology can be found in our earlier report on DER benefits (Hadley et al 2003). Appendix A of that report describes the methodology used in modeling the PJM electric system supply and demand and implemented via the ORCED computer code (Hadley and Hirst, 1998).

DER generation can be treated as a reduction in system demands, with consequent changes in the load duration curves. Comparing the changes in production provides information on system response to the addition of DER resources, including which plants change their operations and the consequent change in emissions.

2.1 PJM System Data

To quantify the impact of DER on the power system we have to model that power system both with and without the DER in question. For this study, we chose to model the PJM-East power pool, which contains most of Pennsylvania, New Jersey, Maryland, and Delaware (Figure 2). It is also referred to as the Mid-Atlantic Area Council (MAAC), one of the reliability councils in the North American Electric Reliability Council. The light-green area represents PJM-West which is located in other reliability council regions.

Figure 2. PJM region including all or parts of Pennsylvania, New Jersey, Maryland, and Delaware.



The PJM region has established a wholesale market system that allows power plants and load-serving entities to buy and sell power on an hourly basis. It uses a bidding system to establish real-time prices that are transparent to the market.

In order to simulate a potentially large amount of DER inclusion in the PJM system, we chose the 2006 time period. Between 2001 and 2006 there is projected to be a relatively large growth in supply (14 GW or 23% growth from 2001). The amounts in later years are flexible and could be modified in the future if DER were to penetrate. We used the demand data for operation of the system from 1999 and increased it by 11.5% to represent the expected growth in demand from then until 2006 based on the *Annual Energy Outlook 2003* (EIA 2002) plus an additional 10% to represent growth in sales to other regions. Power plant data for 1999-2001 were used to establish the operating parameters for existing plants. New plants were added based on announced additions.

2.1.1 PJM Supply

The operating and emissions characteristics of each plant in the PJM region must be defined. One of the input files from the Energy Information Administration (EIA) National Energy Modeling System lists over 19,000 power plant units nationwide, providing capacity, availability, heat rate, emissions, and date of construction and retirement, among other characteristics. (EIA 2003b) (A power plant may have multiple units, and each unit may be further separated in the database if it has multiple owners.) The power plants in the PJM region that were operating in between 1999 and 2001 were pulled from this database, resulting in a list of 803 units with a combined capacity of over 61,000 MW.

Utilities must submit a large amount of financial and operations information to the Federal Energy Regulatory Commission and the EIA. Platts collects this publicly available information, categorizes it, performs some quality checks on it, and distributes it in a convenient computer program called Powerdat (Platts 2003). The data for the power plants in PJM were pulled from the database. Not all power plants in the EIA dataset are included in the Powerdat database, and some of the data in Powerdat is recorded for the entire plant rather than for individual units. Nevertheless, the data provides additional details, especially on fuel and operating costs for the year.

The new capacity additions that began operation or were planned for 2002 through 2005 were taken from the Platts PowerDat data base (Table 2) (Platts 2003). The ORCED model can include only a limited number of new plants so the capacity for Combined Cycle, and Gas Combustion Turbine (CT) were divided into 18 plants of 661 MW each and 13 plants of 104 MW respectively. They were then brought on line to approximately match the planned capacity for 2002 through 2005. The costs and performance characteristics for the new plants are not given in the PowerDat database and were assumed based on information in "Cost and Performance Characteristics of New Electricity Generating Technologies" from EIA's publication *Assumptions to Annual Energy Outlook 2003*. There were only four planned plants that used a fuel other than natural gas, including 2 waste coal plants accounting for about 600 MW, a wind turbine plant (236 MW) and a biomass plant of 20 MW. Because of their nature, these 4 units were assumed to be “Must Run” plants and do not affect the dispatch of the competitive plants except to the extent that they reduce energy demand that the remaining competitive plants are dispatched to serve.

Table 2. New capacity planned for MAAC region (*Platts 2003*)

Type of Capacity	2002	2003	2004	2005	Total Additions after 2001
Combined Cycle	3305	1983	2644	3966	11898
Combustion Turbine	312	1040			1352
Waste Coal			584		584
Wind		236			236
Biomass				20	20
Total	3617	3259	3228	3986	14090

Two further sets of information are available from the Environmental Protection Agency (EPA). It has released a data set for plants used in their Integrated Planning Model (EPA 2002) and in their e-Grid data application (EPA 2001). The files include unit-level data on capacity, heat rate, and emissions rates for SO_2, NO_x, and mercury.

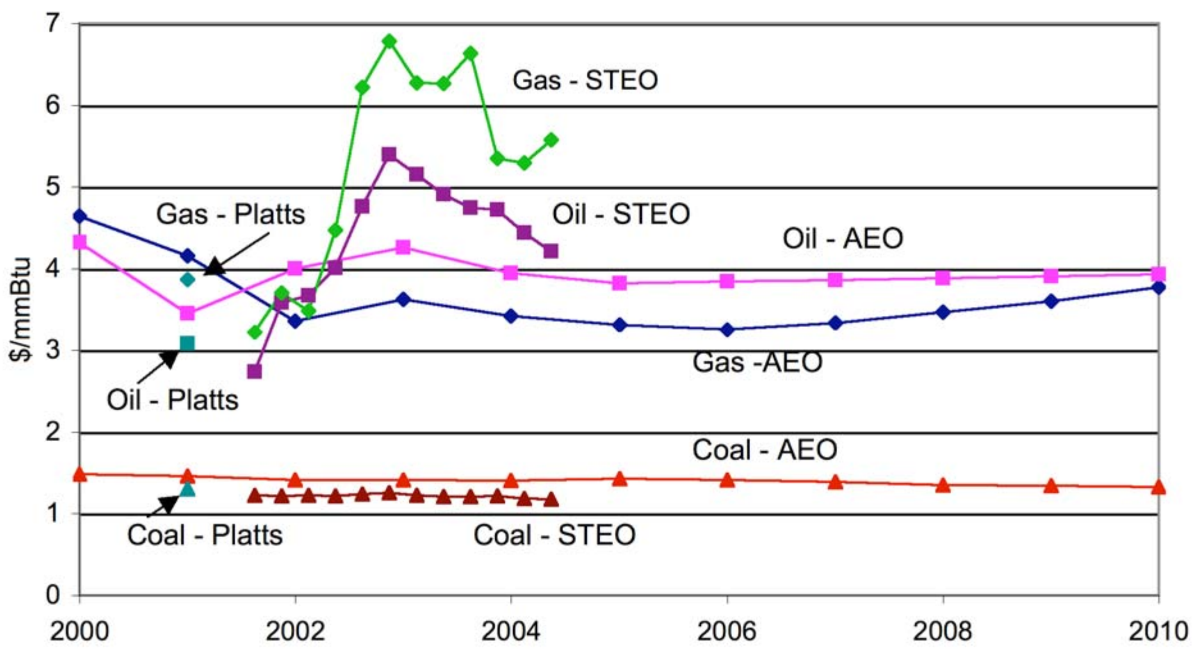
The cost of fuel for each plant is reported in the databases, and the consequent average cost of fuel can be calculated (Table 3). Although the model uses the actual reported cost for each plant, the average provides insight into the general prices paid over these years. These values are shown in Figure 3.

Table 3. Average fuel prices used in study, \$/mmBtu

Fuel	Platts 1999-2001	STEO 2004	AEO 2006
Gas	3.87	5.63	3.25
Oil	3.08	4.53	3.84
Coal	1.30	1.19	1.41

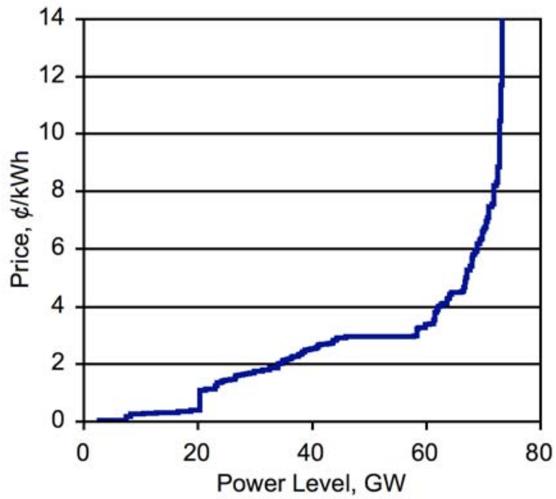
While our main set of scenarios simply used these fuel prices for the analysis, there were two other sets of fuel prices that were used for sensitivity studies. One set came from the Annual Energy Outlook (AEO) 2003 (EIA 2002), which simulates the energy picture for each region of the country for 2000-2025. It was published in December 2002 based on data available through October of that year, and generally shows prices declining after some high values in the near term. Figure 3 shows the prices that it projects for electric utilities in the MAAC region through 2010. Table 3 shows the prices it lists for 2006.

Figure 3. Fuel prices from EIA's Annual Energy Outlook (AEO), Short-Term Energy Outlook (STEO), and PowerDat database (Platts)



The EIA also publishes a Short Term Energy Outlook (STEO) every month that shows expected prices for the next few years (EIA 2003c). Figure 3 includes the prices from the report from June 2003. Note that these are the national values for the various fuels; the report does not show regional prices as the AEO does. It is notable that in the Platts and STEO results, the gas prices are almost \$0.80 and \$1.10/mmBtu higher than the fuel oil prices, but in the AEO the gas prices are lower by \$0.60/mmBtu. This plays a strong role in the relative amounts of gas and oil technologies displaced by DER, as is shown in the sensitivities below.

Figure 4. PJM supply curve

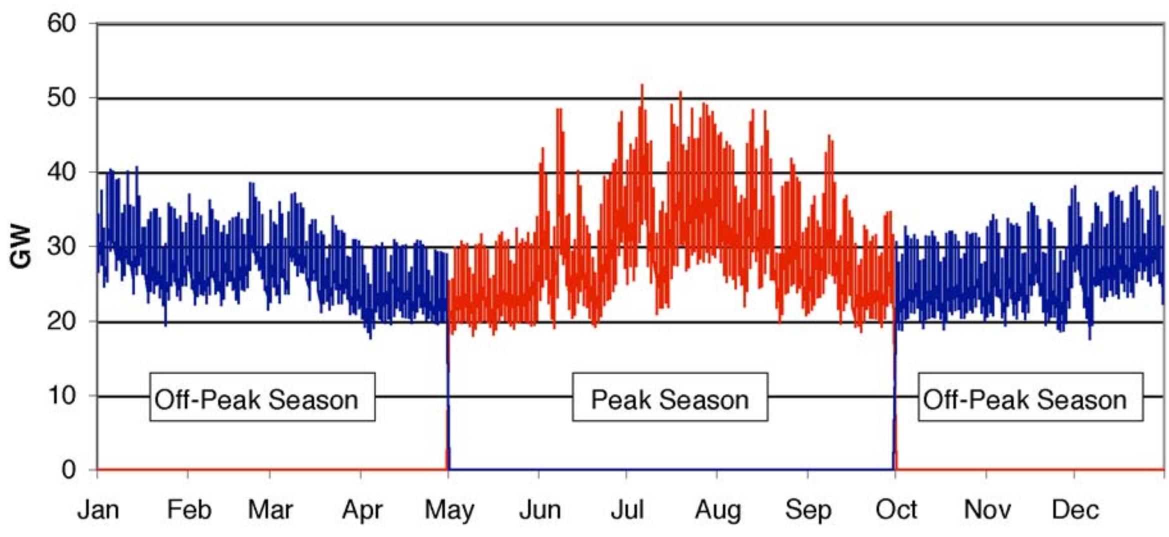


Once the plants were defined, they could be sorted in order of increasing variable cost to create a supply curve for power (Figure 4). The zero price capacity is the non-dispatchable generation, followed by the nuclear capacity at around 0.5¢/kWh. Coal plants report variable cost from ~1.5 to 3 ¢/kWh. Oil and gas plants have variable prices from ~2.5 to 16¢/kWh and beyond. The new combined cycle plants had variable costs of 3¢/kWh and can be seen in the figure as a straight segment between 40 and 60 GW. The new combustion turbines had a variable cost of 4.5 ¢/kWh plus up to 4 ¢/kWh to cover start-up costs depending how infrequently they were called upon.

2.1.2 PJM Demand

The other key factor in determining power plant production is defining the demands on the grid. PJM reports their hourly demands, both current and historical, on their website (PJM 2002). Figure 5 shows the hourly change in demands over the year 1999. Note that the highest demands occur in the summertime, due to the air conditioning requirements. Therefore, a peak season between May 1 and September 30 was selected because NO_X emissions are more heavily regulated in the region during this time. Using this definition allows us to gather more detailed information specific to that season. This hourly data is used to produce an LDC for the peak and off-peak seasons.

Figure 5. PJM hourly system demand for 1999



In this Phase III study, we increased demand in each hour by 11.5% from the values in 1999 to approximate a demand curve for 2006. However, with the expected growth in supplies (above), a growth of only 11.5% resulted in a large overcapacity for the region. To overcome this, we assumed a further 10% growth in demand by sales to other regions of the country. This resulted in a peak demand of 62,500 MW and reserve margin of 18%. Sensitivities were run to evaluate the impact of lower demands and consequent higher reserve margins.

With supply and demand for the no DER case established, the plants can be dispatched and marginal plants determined. Figure 6 shows the dispatch of plants for the peak season by type of plant, and Figure 7 shows the plants for the off-peak season. Note that the large block of gas-fired plants are the plants added between 2001 and 2005. They all are modeled to have the same operating costs so stay together during the dispatch. Some are only dispatched a small percentage of the year, because of their relative fuel cost and the amount of reserves.

Figure 6. Plants dispatched during the peak season by fuel type

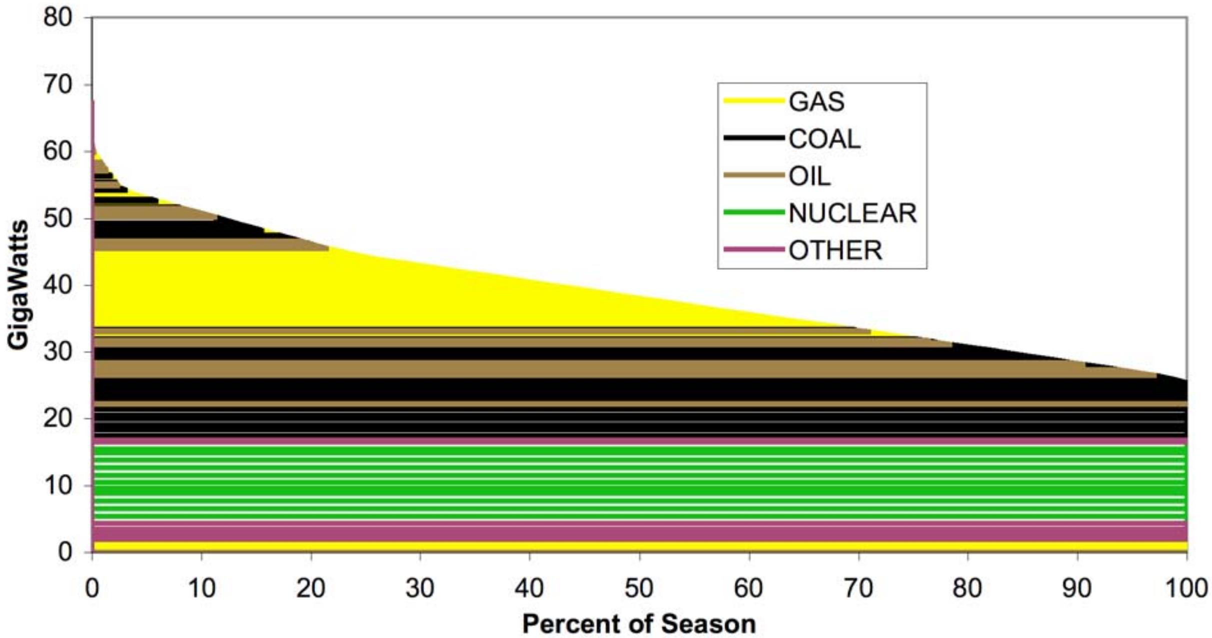
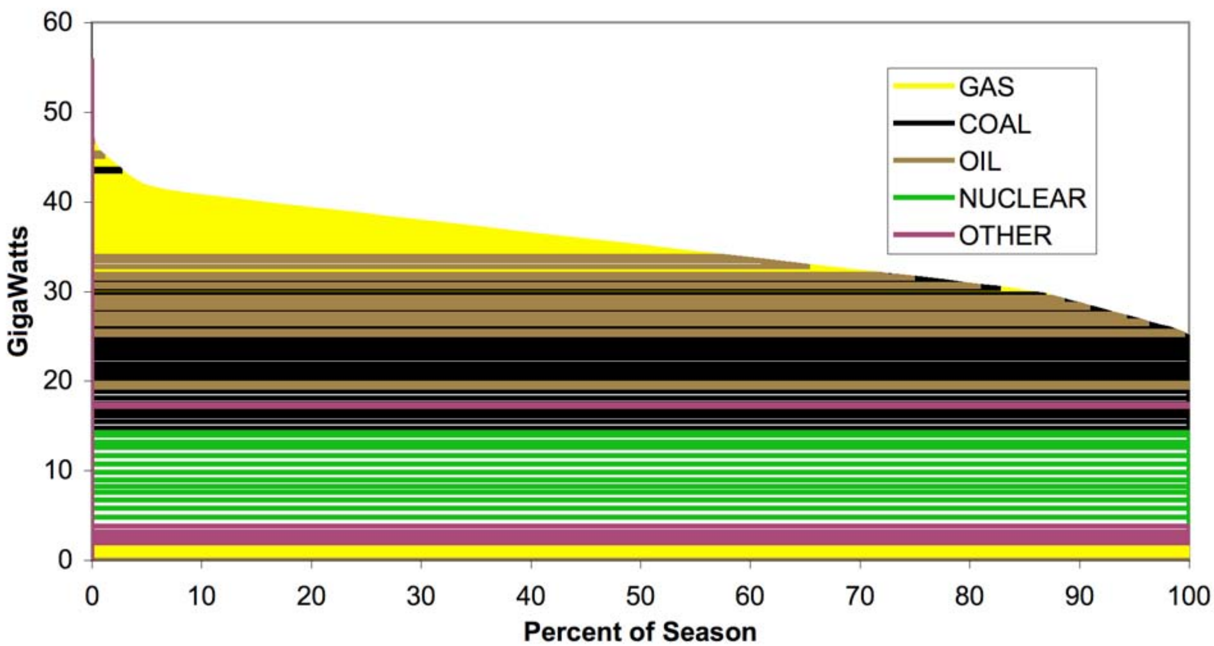


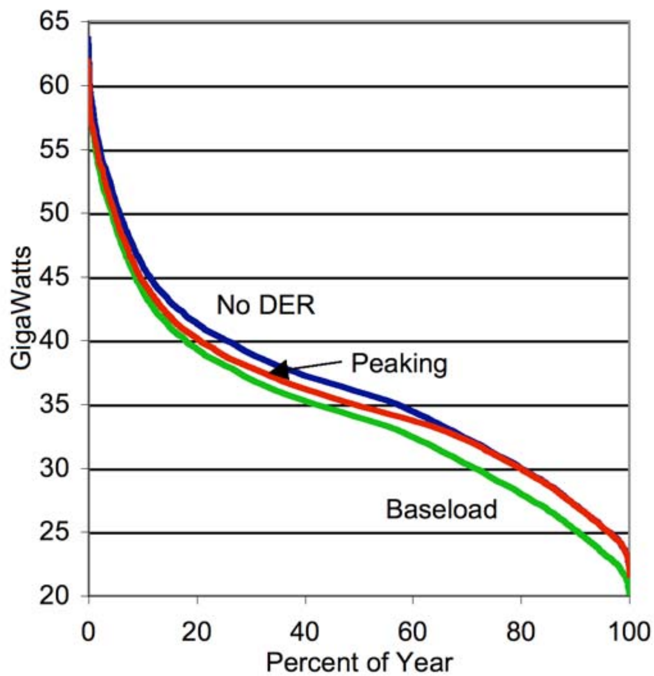
Figure 7. Plants dispatched during the off-peak season by fuel type



2.2 DER additions

To examine the impact of large amounts of DER added to the system, we hypothesized 2000 MW of DER capacity added. With capacity increasing by 14,000 MW in our analysis, this is below the long-term goal of 20% of new capacity coming from DER, but is still more than likely will be developed by 2006. Two scenarios were run: one with 2000 MW of DER running all the time (Baseload), and one with 2000 MW of DER running from 8 am to 8 pm on weekdays (Peaking). Actual DER operations would be more complex than this. The Baseload DER system would have some downtime at different times of the year that would lower its capacity, while the Peaking DER would have some fraction operating at earlier or later times, or on weekends.

Figure 8. Annual LDCs with no DER, Peaking DER, and Baseload DER removed from demand



The Baseload scenario simply had the demands on the system for every hour drop by 2000 MW (Figure 8). The LDC was lowered at all points. The Peaking scenario had a more complex impact on the LDC because it only lowered demand in certain hours. The annual system peak only dropped 510 MW instead of 2000 MW because system peak demands during weekends were not affected.

The DER used for the analysis was a low NO_X CT used in the Phase II analysis. Its characteristics are shown in Table 4, along with pertinent parameters of the new combined cycle plants (EIA 2003a) and existing non-electrical boilers, also from the Phase II study. The Solar Mars 90 is a 9.5 MW turbine with dry Low-NO_X combustion and 5 ppm NO_X SCR. With an electrical efficiency of 29% and a heat exchanger efficiency of 62%, the total efficiency of the DER is 73%.

If the exhaust heat from the DER is used for thermal energy at the facility where it is located, then the DER can replace some or all of the existing thermal needs of the site. This reduces or removes the need for boilers, chillers, or other equipment for process heat. To analyze the change in energy and emissions if CHP is used, we modeled the displaced thermal source as a boiler with the characteristics shown in Table 4.

Both the DER and the CC facility are modeled as low-NO_X emitters, while the thermal boiler modeled has emissions based on the average value for gas-fired steam turbine-boilers (ST) in the region, as in the Phase II study. Typically, NO_X emissions are reported in terms of lb/mmBtu of thermal energy in. In Table 4, we also calculate the emissions in terms of lb/mmBtu of useful energy out. For the new CC, the value is the amount in divided by its electrical efficiency while for the boiler the value is the amount in divided by its heat exchanger or thermal efficiency. However, the DER in CHP mode creates both electrical and thermal output and its emissions are the input amount divided by its combined efficiency of 73%. Similarly, since all three technologies use natural gas, they have the same CO_2 emissions based on input energy. However, based on useful energy out, the DER is the least polluting.

Table 4. Distributed generation (with CHP) and alternative technologies

Model/Type	Capital Cost, \$/kW	O&M Cost, \$/MWh	Electrical Efficiency	Heat Exchanger Efficiency	NO_X emissions, lb/mmBtu		CO_2 emissions, lb/mmBtu	
					In	Out	In	Out
Solar Mars 90	785	15	29%	62%	0.022	0.030	117	160
New Gas CC	536	2.0*	49%	–	0.02	0.041	117	240
Non-electric Boiler			–	72%	0.23	0.32	117	162

* Plus \$12/kw-yr fixed O&M cost

Source: Iannucci 2002, EIA 2003

Given that adding DER does not necessarily mean displacing an equal amount of CC, the actual changes in emissions will be different than shown in the table. If the DER displaces higher emitting sources then of course the reduction in emissions will be greater.

3. Analysis

Once the supplies and demands were defined then a set of cases were run using ORCED. As mentioned above, there are three extremes of possible responses to the addition of DER: no change in central system capacity, new plants are cancelled before construction, or old plants are retired. The actual response may be a mix of these scenarios, but evaluating these will show the range of impacts on the central grid.

3.1 DER adds to reserve margin

The first set of cases assumed that even though the DER was installed, no new plants were cancelled or older plants retired. Instead the reserve margin increased from 18% to 19% in the Baseload DER scenario and 22% in the Peaking DER scenario. This scenario is similar to the analysis carried out in the Phase II report, but with higher levels of DER.

Figure 9. Generation displaced by DER if no central capacity cancelled or retired

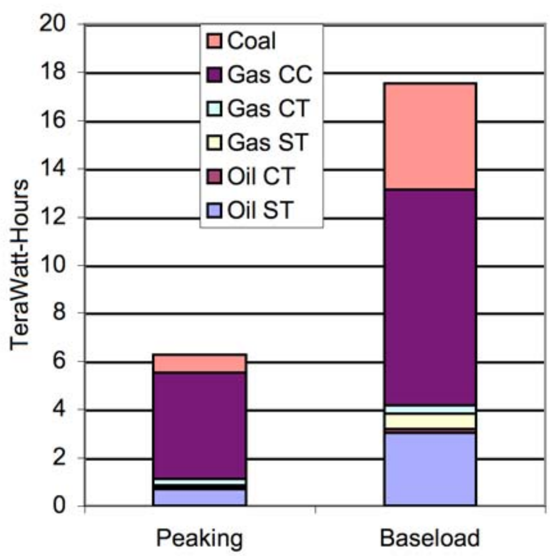


Table 5. Generation displaced by DER if no central capacity cancelled or retired (GWh)

Plant Type	Peaking		Baseload	
Coal	744	12%	4383	25%
Gas CC	4413	70%	8985	51%
Gas CT	263	4%	344	2%
Gas ST	85	1%	619	4%
Oil CT	59	1%	168	1%
Oil ST	699	11%	3021	17%
Total	6264	100%	17520	100%

Table 6. Energy and emissions parameters of displaced generation

	Peaking	Baseload
Avg Displaced Efficiency	40%	38%
CO_2, lb/MWh	1194	1423
NO_X, lb/MWh	1.14	1.87
SO_2, lb/MWh	3.41	6.78

Figure 9 and Table 5 show the different central generating technologies that get displaced by the added DER. Although the same amount of capacity was available, the plants did not run for as much of the year; the plant on the margin at any point in time was the plant that is reduced. Gas CC made up a significant portion of the displaced power, but not all of it. In the Baseload scenario especially, coal and oil-fired steam generation was also displaced.

The large amount of CC capacity on the margin means that average electrical efficiency was relatively high (38% - 40%) compared to the electricity efficiency of the DER (29%) that displaced it (Table 6). Replacing the lost generation with DER changed the amount of primary energy and emissions used to provide the energy services. Without CHP, only electricity services were replaced. With CHP, some amount of other thermal energy needs was replaced by the exhaust from the DER. Table 7 shows the changes in energy and major air pollutants. The central generation displaced by the DER was more efficient so the total primary energy for electricity generation was higher. However, if the thermal energy from the DER is used, the net energy use declined. CO_2 emissions reflect these same factors, with emissions higher with DER if CHP displacement is not included. However, NO_X and SO_2 emissions declined with the use of DER even without CHP. Despite the high amount of CC that was displaced, the total central generation displaced had higher emissions than DER. Including the emissions displaced from the thermal sources by CHP made the savings even higher.

Table 7. Primary energy use, CO_2, NO_x, and SO_2 emissions from 2000 MW of Combustion Turbine-6B with and without CHP if no generation is cancelled or retired

		Dist. Gen.	Electric System	Net w/o CHP	Thermal System	Net w/ CHP
Primary Energy, TBtu	Peaking DER	74	-53	21	-46	-24
	Baseload DER	208	-159	49	-128	-79
CO_2, MTons	Peaking DER	4.4	-3.7	0.6	-2.7	-2.1
	Baseload DER	20.8	-15.9	4.9	-12.8	-7.9
NO_X, kTons	Peaking DER	0.8	-3.6	-2.8	-10.5	-13.3
	Baseload DER	2.3	-16.4	-14.1	-29.4	-43.5
SO_2, kTons	Peaking DER	0.0	-10.7	-10.7	0.0	-10.7
	Baseload DER	0.0	-59.4	-59.4	0.0	-59.4

3.2 DER displaces new capacity

The next set of scenarios involved removing 2000 MW of new CC capacity from the ORCED runs with DER. This changed the reserve margin in the baseload scenario to 18.7% (from the reference case of 18.1%) while the Peaking scenario reserve margin dropped to 15.8%. This latter reduction is because the annual peak demand did not drop 2000 MW but only 511 MW since the DER did not change the weekend peaks.

Surprisingly, the relative amounts of displaced generation did not change significantly in the Baseload scenario with the cancellation of the CC; CC displacement increased from 51% to 60% of the DER production, with consequent reductions in the other technologies (Figure 10). The normal thought would be that the DER would displace only CC production since the equivalent capacity was cancelled. Instead, at some times of the year other technologies were on the margin and so were reduced. In the Baseload scenario the DER was run at effectively 100% capacity factor, so even if the cancelled CC had operated at its full availability of 86%, then other technologies would have been called upon to reduce their production. In the reference case, furthermore, the new CC had a marginal cost of 2.93 ¢/kWh which made it more of an intermediate producer, operating with a capacity factor between 60% and 15%, depending on the plant.

In the Peaking scenario, the cancellation of new CC meant that almost all of the DER generation displaced possible CC generation. However, small amounts of other generation were also displaced and CT generation actually increased slightly to make up for the loss of CC capacity during peak times (Table 8). The DER capacity more nearly aligned with the capacity of the cancelled production.

Figure 10. Generation displaced by DER if 2000 MW of CC capacity is cancelled compared to if no capacity is cancelled

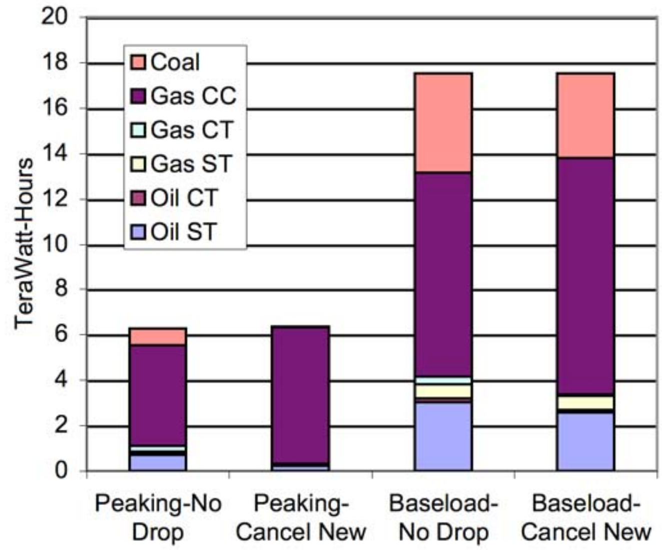


Table 8. Generation displaced by DER if 2000 MW of CC capacity is cancelled (GWh)

Plant Type	Peaking		Baseload	
Coal	39	1%	3720	21%
Gas CC	6009	96%	10452	60%
Gas CT	-84	-1%	47	0%
Gas ST	65	1%	607	3%
Oil CT	15	0%	130	1%
Oil ST	219	4%	2564	15%
Total	6264	100%	17520	100%

As with the first set of cases, primary energy use and CO_2 emissions increased with DER used only for electricity, but decreased if CHP was used (Table 9). SO_2 and NO_X emissions declined even from the electricity generation because of the low emissions from DER, except for NO_X in the Peaking scenario. In that case, the low NO_X emissions from CC mean that net emissions without CHP were higher with DER.

Table 9. Primary energy use, CO_2, NO_x, and SO_2 emissions from 2000 MW of Combustion Turbine-6B with and without CHP if 2000 MW of CC capacity is cancelled

		Dist. Gen.	Electric System	Net w/o CHP	Thermal System	Net w/ CHP
Primary Energy, TBtu	Peaking DER	74	-45	30	-46	-16
	Baseload DER	208	-152	57	-128	-71
CO_2, MTons	Peaking DER	4.4	-2.7	1.6	-2.7	-1.0
	Baseload DER	20.8	-15.2	5.7	-12.8	-7.1
NO_X, kTons	Peaking DER	0.8	-0.7	0.1	-10.5	-10.4
	Baseload DER	2.3	-13.7	-11.4	-29.4	-40.8
SO_2, kTons	Peaking DER	0.0	-1.6	-1.6	0.0	-1.6
	Baseload DER	0.0	-50.7	-50.7	0.0	-50.7

3.3 DER accelerates retirements

For various reasons, it may be that instead of causing cancellations of new plants, the addition of DER will encourage the retirement of older plants. It may be that the older plants are very inefficient or polluting, such that it is more cost-effective to replace them with new capacity (new CC or DER.) Alternatively, the new plants and old plants may be owned by different groups with different motivations for continuing (or discontinuing) their operation. As an example, Reliant Energy has recently announced the mothballing of some of their peaking and intermediate plants in the mid-Atlantic region due to low sales (Reuters 2003).

To explore this, we examined the finance and operations of the central plants in the scenario with no plants retired (section 3.1) to find which existing plants had the highest avoidable losses per unit of available capacity. The losses were defined as the revenues minus the out-of-pocket costs, including the variable costs such as fuel and the fixed and variable O&M costs, but not including sunk capital costs such as depreciation. We then retired the first 2000 MW, which included 1,475 MW of oil capacity, 300 MW of coal, and 225 of gas.

Figure 11. Generation displaced by DER if 2000 MW of existing capacity is retired compared to if no capacity retired

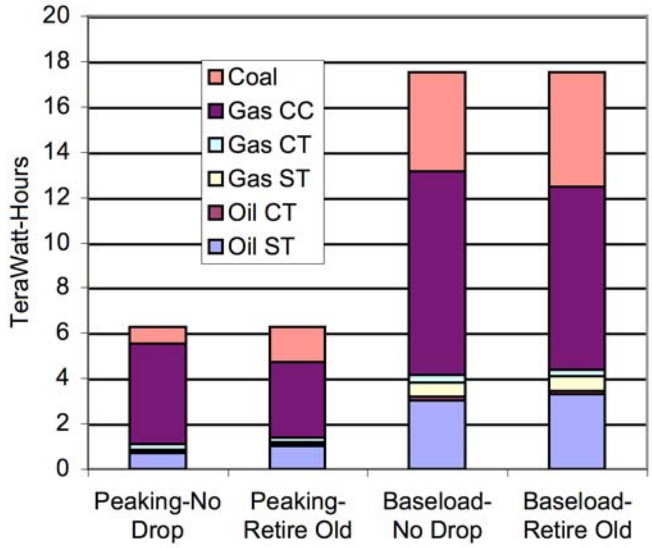


Table 10. Generation displaced by DER if 2000 MW of existing capacity is retired (GWh)

Plant Type	Peak		Baseload	
Coal	1543	25%	5052	29%
Gas CC	3342	53%	8099	46%
Gas CT	196	3%	283	2%
Gas ST	108	2%	641	4%
Oil CT	48	1%	158	1%
Oil ST	1027	16%	3287	19%
Total	6264	100%	17520	100%

After retiring these plants, we ran the Peaking and Baseload DER scenarios (Figure 11 and Table 10). As would be expected, oil and coal technologies had larger displacement than in the other scenarios. Their generation declined because of the addition of DER and concomitant retirement of their capacity.

The retirement of older, more inefficient capacity meant that the DER had a more positive impact on the environment (Table 11). While primary energy was still higher with the DER before CHP, the CO_2 emissions were less in the Peaking scenario because of the inefficiency and fuel type of the displaced energy.

Table 11. Primary energy use, CO_2, NO_x, and SO_2 emissions from 2000 MW of Combustion Turbine-6B with and without CHP if 2000 MW of existing capacity is retired

		Dist. Gen.	Electric System	Net w/o CHP	Thermal System	Net w/ CHP
Primary Energy, TBtu	**Peaking DER**	74	-57	18	-46	-28
	Baseload DER	208	-162	46	-128	-82
CO_2, Mtons	**Peaking DER**	4.4	-4.4	-0.1	-2.7	-2.7
	Baseload DER	20.8	-16.2	4.6	-12.8	-8.2
NO_X, kTons	**Peaking DER**	0.8	-6.0	-5.2	-10.5	-15.7
	Baseload DER	2.3	-18.4	-16.1	-29.4	-45.5
SO_2, kTons	**Peaking DER**	0.0	-12.9	-12.9	0.0	-12.9
	Baseload DER	0.0	-61.1	-61.1	0.0	-61.1

3.4 Sensitivities

Two large uncertainties exist in modeling future electricity markets: fuel prices and the relative supply and demand for power. The reference scenarios above used fuel prices based on data for PJM between 1999 and 2001. Other recent forecasts give prices that are higher and lower than those values. Separately, our reference scenario adjusted supplies and demands to achieve reserve margins that are more typical over the long-term. However, recent activity in the market has created a temporary glut in capacity. How quickly this overcapacity will come into balance and how it will do so is not known. We chose to run one sensitivity with the original amounts of capacity and demands for 2006 (without the assumption of 10% increase for exports) to see how this would impact displacement by DER.

3.4.1 High gas prices

The EIA publishes their Short-Term Energy Outlook (STEO) on a monthly basis. It gives quarterly price projection for the next several years, and is generally more accurate than the long-term forecasts that are available from the Annual Energy Outlook. Recent changes in the gas market especially have caused great volatility in prices (Figure 3). The forecast oil and gas prices for 2004 are roughly $1.5 /mmBtu higher than the average prices based on the Platts data for 1999-2001 (Table 3).

Figure 12. Generation displaced with new CC capacity cancelled and reference (Platts) and high (STEO) gas prices

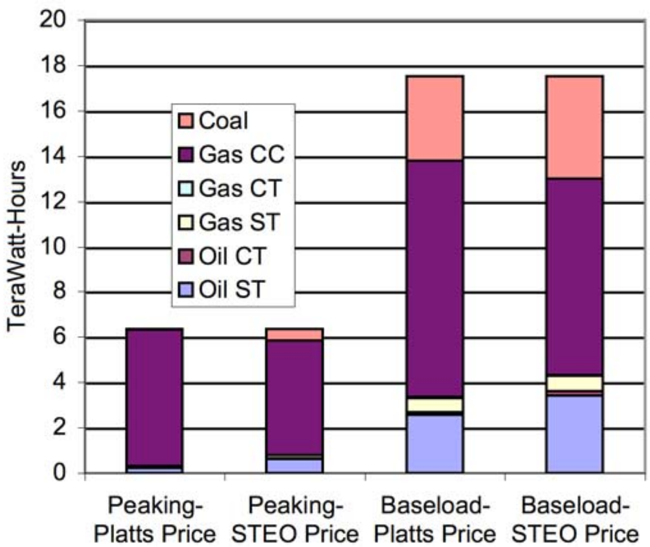


Table 12. Generation displaced with capacity cancelled and high (STEO) gas prices (GWh)

Plant Type	Peak		Baseload	
Coal	506	8%	4510	26%
Gas CC	5031	80%	8694	50%
Gas CT	-70	-1%	41	0%
Gas ST	140	2%	678	4%
Oil CT	33	1%	184	1%
Oil ST	624	10%	3413	19%
Total	6264	100%	17520	100%

With the oil and gas prices higher than the base case, the main beneficiary was the coal production. Without any change due to DER, coal-fired generation increased by 9% while oil decreased by 9% and gas by 18%. Consequently, while the DER displaced gas CC (because of the 2000 MW of cancellations), coal and oil production was also on the margin and so was reduced.

Because of the displacement of coal and oil by DER, NO_X and SO_2 emissions declined with the use of DER, even just considering the electricity generation (Table 13). With the added savings from thermal system reductions, energy and CO_2 were reduced as well.

Table 13. Primary energy use, CO_2, NO_x, and SO_2 emissions from 2000 MW of CT-6B with and without CHP if 2000 MW of new CC capacity is cancelled and gas prices are higher

		Dist. Gen.	Electric System	Net w/o CHP	Thermal System	Net w/ CHP
Primary Energy, TBtu	**Peaking DER**	74	-49	26	-46	-20
	Baseload DER	208	-158	50	-128	-78
CO_2, Mtons	**Peaking DER**	4.4	-3.3	1.0	-2.7	-1.6
	Baseload DER	20.8	-15.8	5.0	-12.8	-7.8
NO_X, kTons	**Peaking DER**	0.8	-2.6	-1.8	-10.5	-12.3
	Baseload DER	2.3	-17.3	-15.0	-29.4	-44.4
SO_2, kTons	**Peaking DER**	0.0	-7.9	-7.9	0.0	-7.9
	Baseload DER	0.0	-63.9	-63.9	0.0	-63.9

3.4.2 Low gas prices

With gas prices lower than oil prices, the dispatch order will change so that gas-fired plants run more often. In these cases, cancelled gas-fired capacity can have a more significant impact. If the cancelled capacity would have run more than the DER that replaces it, then other technologies will have to run more to make up the difference. This occurred a little in the Peaking scenario using the reference fuel prices (section 3.2), but with lower gas prices is more pronounced.

The AEO 2003 has gas prices for electric utilities in the Mid-Atlantic region (New York, New Jersey, and Pennsylvania) 60¢/mmBtu lower than residual oil prices in 2006 ($3.25 versus $3.85) (Figure 3). These are opposite what the Platts data and the STEO show in the nearer term. Using these prices, the new CC capacity operated approximately 49% of the year, which was higher than the 36% of the year that the peaking DER operates. As a consequence, the other technologies increased their operation (Table 14 and Figure 13). In the Baseload scenario, the DER production was greater than the lost CC production and so other technologies also reduced their operations.

Figure13. Generation displaced with capacity cancelled and reference (Platts) and low (AEO) gas prices

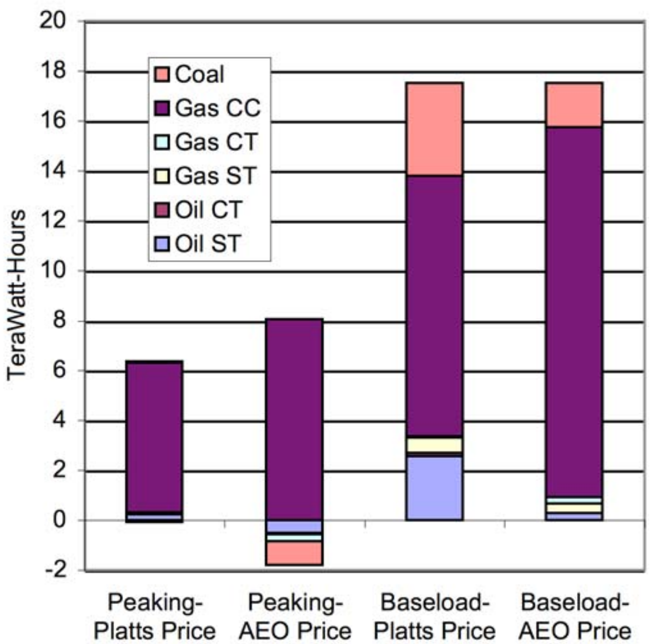


Table 14. Generation displaced with capacity cancelled and low gas prices (GWh)

Plant Type	Peaking		Baseload	
Coal	-954	-15%	1761	10%
Gas CC	8052	129%	14828	85%
Gas CT	-277	-4%	278	2%
Gas ST	3	0%	362	2%
Oil CT	-33	-1%	15	0%
Oil ST	-527	-8%	277	2%
Total	6264	100%	17520	100%

Table 15. Energy and emissions parameters of displaced generation

	Peaking	Baseload
Avg Displaced Efficiency	58%	45%
CO_2, lb/MWh	491	995
NO_X, lb/MWh	-0.83	0.76
SO_2, lb/MWh	-4.21	2.33

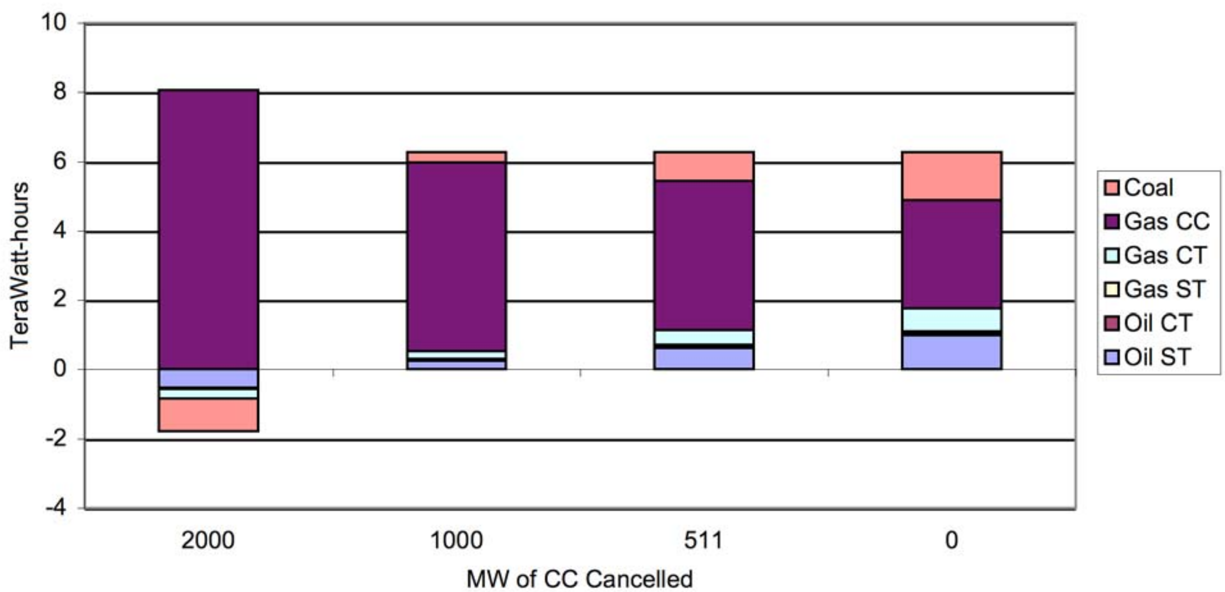
The energy and emissions parameters also showed the impact of the cancellations and change in operations (Table 15). While central electricity production decreased by the amount of the DER, 6264 GWh or 21.4 TBtu in the Peaking scenario, efficient gas CC decreased more and inefficient CT and ST production increased. This caused the primary energy use to decline by only 37 TBtu (Table 16), resulting in a quasi-efficiency of 21.4/37 or 58%. Even if CHP was used, the total energy savings was only 8 TBtu. Another crucial factor is that with the increase in coal use to make up for the loss of CC, total SO_2 emissions for the Peaking scenario increased as well. However, in both scenarios the NO_X emissions were reduced, largely due to savings from CHP.

Table 16. Primary energy use, CO_2, NO_x, and SO_2 emissions from 2000 MW of CT-6B with and without CHP if 2000 MW of new CC capacity is cancelled and gas prices are lower

		Dist. Gen.	Electric System	Net w/o CHP	Thermal System	Net w/ CHP
Primary Energy, TBtu	**Peaking DER**	74	-37	38	-46	-8
	Baseload DER	208	-134	75	-128	-53
CO_2, Mtons	**Peaking DER**	4.4	-1.5	2.8	-2.7	0.1
	Baseload DER	20.8	-13.4	7.5	-12.8	-5.3
NO_X, kTons	**Peaking DER**	0.8	2.6	3.4	-10.5	-7.1
	Baseload DER	2.3	-6.6	-4.3	-29.4	-33.7
SO_2, kTons	**Peaking DER**	0.0	13.2	13.2	0.0	13.2
	Baseload DER	0.0	-20.4	-20.4	0.0	-20.4

Since the Peaking DER scenario only lowered the peak demand by 511 MW rather than the full 2000 MW, and the new capacity was operated more as baseload, it becomes more likely that only a fraction of the new CC capacity might be cancelled. To explore the changing displacement, we ran the Peaking scenario with only 1000, MW, 511 MW, and 0 MW of CC cancelled. The results are shown in Figure 14. As the amount of cancelled CC capacity was reduced, the amount of CC generation displaced dropped as well. Then several other technologies were also reduced; CC generation represented 129%, 87%, 69%, and 50% of the total generation reduction as cancelled capacity dropped from 2000 to 0 MW.

Figure 14. Displaced generation with 2000 MW of Peaking DER, low gas prices, and varying amounts of CC capacity cancelled



3.4.3 Capacity Reserve Margin

In our reference scenarios we increased customer demands by 10% above the amount predicted for the MAAC region to represent sales from the region and to more fully utilize the plants being built in the region. However, it may occur that the plants are built but sales do not increase, leaving the region with an even larger amount of surplus capacity than in the reference scenarios. We removed the 10% increase and reran the scenario with no DER and with 2000 MW of DER causing the cancellation of new CC plants. While the reference scenario had a reserve margin of 18%, the new set of cases had a reserve margin of 30%. Figure 15 shows the change in central generation for both the reference demand scenarios and with 10% lower demands. Table 17 shows the actual amounts of reduction for the various technologies under reduced demands.

Figure 15. Generation displaced with new CC capacity cancelled and reference and low customer demands

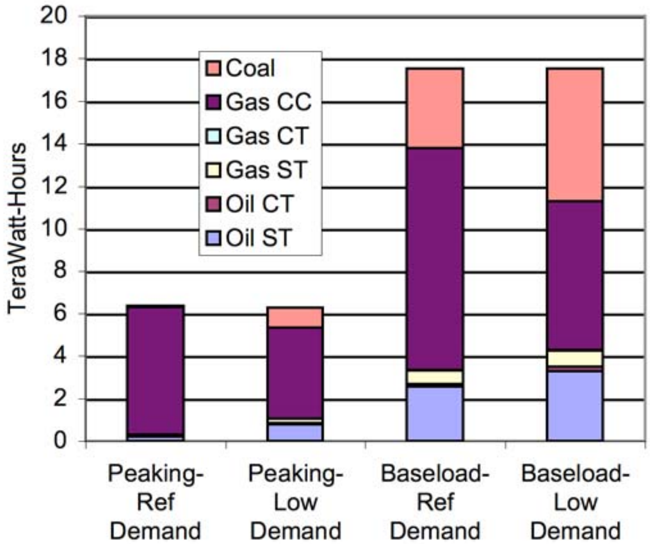


Table 17. Generation displaced with capacity cancelled and low customer demands (GWh)

Plant Type	Peak		Baseload	
Coal	938	15%	6237	36%
Gas CC	4277	68%	7015	40%
Gas CT	-10	0%	6	0%
Gas ST	229	4%	764	4%
Oil CT	57	1%	203	1%
Oil ST	773	12%	3295	19%
Total	6264		17520	

With lower customer demands and higher reserve margins, some of the lower cost coal and oil plants were on the margin more often so were reduced when the DER further reduced demand. New CC capacity had a lower capacity factor than in the reference scenarios, 15% instead of 27%, so the displaced power came from other, higher emitting technologies besides CC. Consequently, emissions reductions were better when DER was used with the lower customer demands than with the reference demands (Table 18 versus Table 9).

Table 18. Primary energy use, CO_2, NO_x, and SO_2 emissions from 2000 MW of CT-6B with and without CHP if 2000 MW of new CC capacity is cancelled and customer demands are lower

		Dist. Gen.	Electric System	Net w/o CHP	Thermal System	Net w/ CHP
Primary Energy, TBtu	Peaking DER	74	-53	22	-46	-24
	Baseload DER	208	-163	46	-128	-82
CO_2, Mtons	Peaking DER	4.4	-3.8	0.6	-2.7	-2.1
	Baseload DER	20.8	-16.3	4.6	-12.8	-8.2
NO_X, kTons	Peaking DER	0.8	-3.8	-3.0	-10.5	-13.5
	Baseload DER	2.3	-20.8	-18.5	-29.4	-47.9
SO_2, kTons	Peaking DER	0.0	-13.8	-13.8	0.0	-13.8
	Baseload DER	0.0	-84.1	-84.1	0.0	-84.1

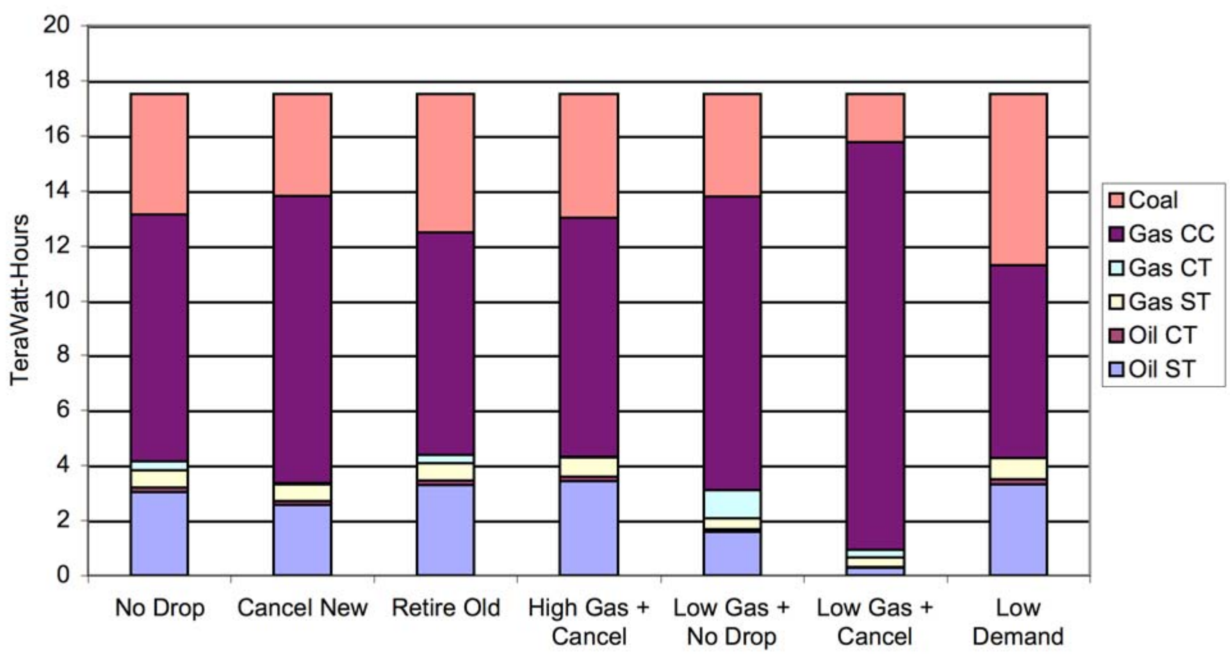
4. Results & Conclusions

This analysis shows that in most cases the introduction of DER does not lead to the displacement solely of new gas CC generation, even if gas CC capacity is cancelled as a result of the DER. And even if the DER does displace CC generation, the net impact is lower NO_X, SO_2, and CO_2 emissions, especially when including the CHP potential benefits of DER.

Two main DER scenarios were evaluated: DER operating all the time (Baseload) and DER operating only during weekdays (Peaking). In response to the DER, three possible reactions by the central grid were evaluated: no reduction in central generation capacity, cancellation of an equivalent amount of new capacity, and retirement of an equivalent amount of old capacity. Sensitivities to fuel prices, amount of cancellation, and base level of demand were evaluated.

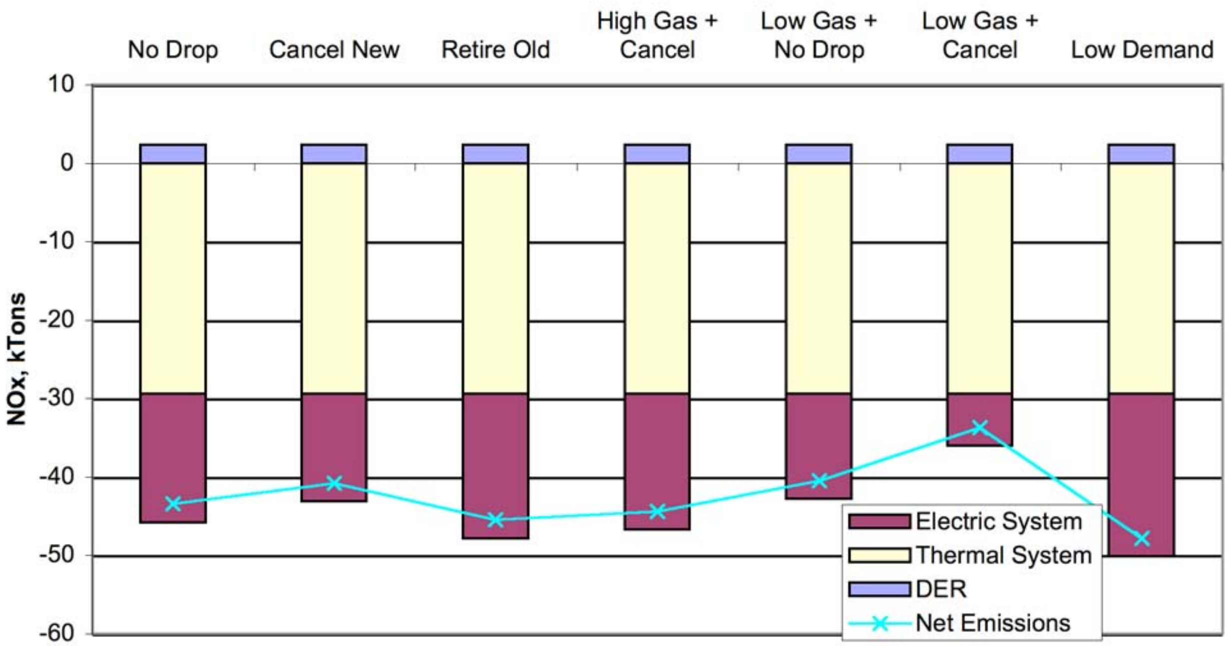
With Baseload DER, all types of central generation were displaced to some extent, regardless of whether new plants were cancelled, old plants retired, gas prices set high or low, or customer demands lowered (Figure 16). Cancellation of new CC had a small impact on the relative amount of displaced generation as did low gas prices, but the largest impact was if there was both cancellation and low gas prices. If prices for gas remain high relative to fuel oil and coal, then DER will succeed in displacing these other, dirtier technologies instead of just new gas-fired production.

Figure 16. Central generation displaced by DER operating year-round in different scenarios



Because other technologies were displaced besides new, clean gas-fired CC, primary energy use went down and emissions of critical pollutants (SO_2, NO_X, and CO_2) decreased as well. A key advantage of DER is the capability to use the exhaust heat of the electric generation for other thermal uses at the site. If this displaces gas-fired combustion as in typical boilers then energy and emission savings are even more pronounced. Figure 17 shows the net emissions for the Baseload DER under each of the scenarios analyzed. Both the DER emissions and the Thermal System savings were the same in each case because the equal amount of production. In all cases, the emissions from the electric system went down as well, as the DER displaced other generation. The scenario with the smallest net impact was the one with low gas prices and cancellation of new gas-fired CC capacity. Since this capacity was even cleaner than the DER then there were only small emissions reductions from that capacity, but the displacement of other technologies besides CC (i.e., coal, oil, and other gas technologies, see Figure 16) contributed as well. Reductions in primary energy and other emissions show similar patterns to the NO_X emission results.

Figure 17. Net NO_X emissions from Baseload DER under varying scenarios



With DER operating only during weekdays, the situation was more complex (Figure 18). Cancellation of 2000 MW of new capacity under the reference power prices resulted in roughly equivalent displacement by DER. Retirements or simply increased reserves resulted in other technologies besides Gas CC being displaced. Although 2000 MW of DER were deployed, peak demands only dropped 511 MW. (Weekday hours are only 36% of the year.) If cancelled capacity would have operated for a larger percent of that time if it had not been cancelled (such as in the scenario with low gas prices) then its cancellation caused other technologies to increase their production. However, even at low prices, if cancellations were closer to the reduction in the peak demand, then all technologies had some displacement from the DER.

The Peaking DER sets of scenarios show a similar pattern emissions reductions to the Baseload scenarios, but because DER displaced a higher proportion of new CC when the CC was cancelled, and because the Peaking DER generated less power and thermal energy, the net emissions savings were less (Figure 19). Most unusual was the scenario with low gas prices and canceling 2000 MW of new CC. Because this scenario resulted in increased generation from coal and other central plants, the emissions from the electric system increased rather than decreased. However, the savings from the modeled thermal system more than made up for the additional emissions and the net emissions were negative.

Figure 18. Central generation displaced by DER operating weekdays only in different scenarios

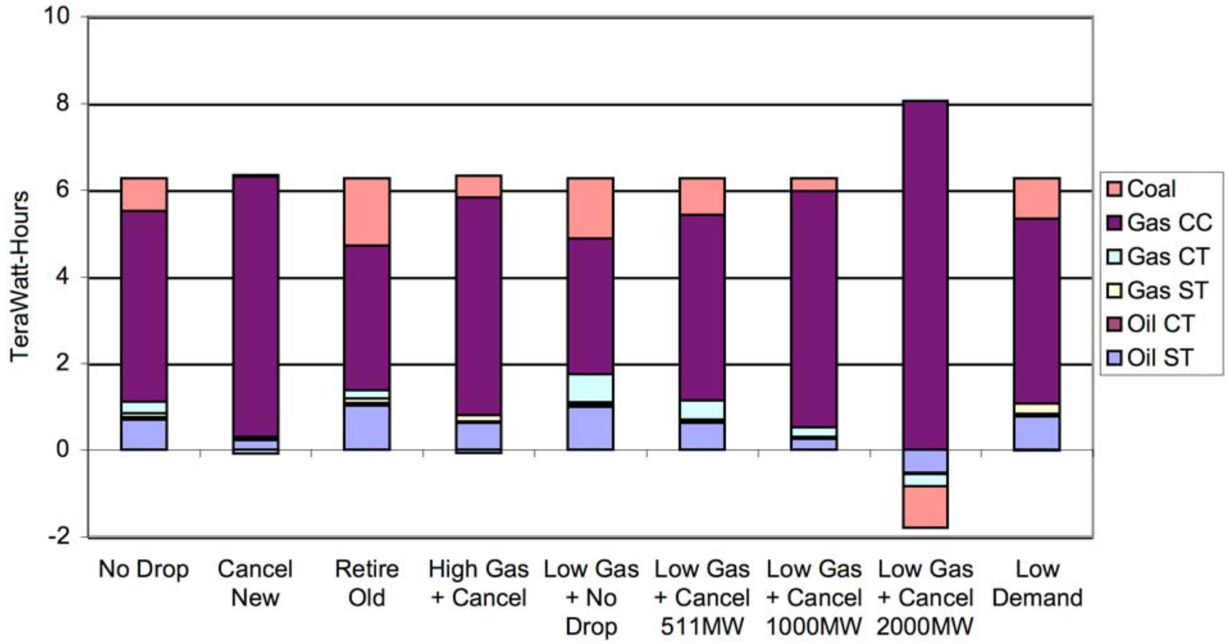
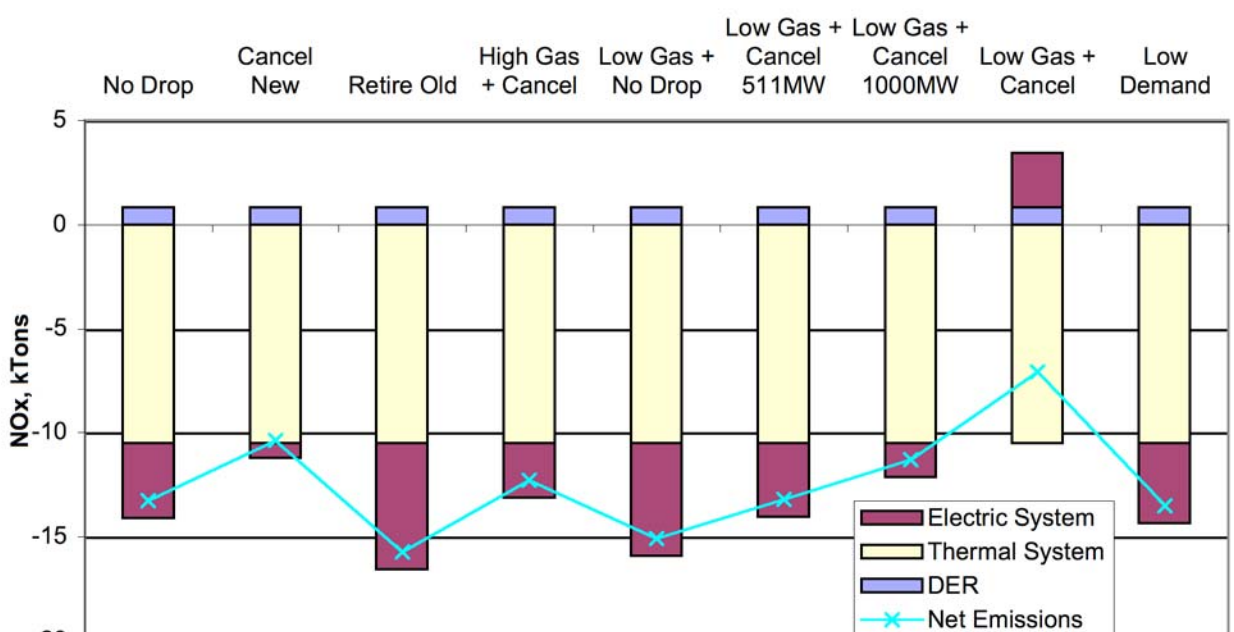


Figure 19. Net NO_X emissions from Peaking DER under varying scenarios



Another way to view the results of all the scenarios is the net change in energy or emissions as a fraction of the gross energy use or emissions of the DER (Table 19). With no CHP, net energy use and CO_2 emissions were generally positive but were negative when thermal energy from DER was used in CHP. NO_X emissions from DER were very low so that net emissions were negative even with just electricity generation.

Table 19. Net changes in energy and emissions as a fraction of the DER's amounts for all scenarios studied. Positive means a net increase and negative means a net savings. NO_X changes are shown as a ratio to the DER emissions. SO_2 changes are "+" or "-" since DER emits no SO_2.

System change	Fuel prices	Demand	DER mode	Primary Energy		CO_2		NO_X		SO_2	
				No CHP	With CHP	No CHP	With CHP	No CHP	With CHP	No CHP	With CHP
No cancel	Platts (Ref)	2006 +10%	Peak	28%	-32%	14%	-48%	-4x	-17x	-	-
			Base	24%	-38%	24%	-38%	-6x	-19x	-	-
Cancel 2000 new	Platts (Ref)	2006 +10%	Peak	**41%**	**-22%**	**36%**	**-23%**	**+.1x**	**-13x**	**-**	**-**
			Base	27%	-34%	27%	-34%	-5x	-18x	-	-
Retire 2000 old	Platts (Ref)	2006 +10%	Peak	**24%**	**-38%**	**-2%**	**-61%**	**-6x**	**-20x**	-	-
			Base	**22%**	**-39%**	**22%**	**-39%**	**-7x**	**-20x**	-	-
Cancel 2000 new	STEO (High)	2006 +10%	Peak	35%	-27%	23%	-36%	-2x	-15x	-	-
			Base	24%	-38%	24%	-38%	-7x	-19x	-	-
Cancel 2000 new	AEO (Low)	2006 +10%	Peak	**51%**	**-11%**	**64%**	**2%**	**+4x**	**-9x**	**+**	**+**
			Base	36%	-25%	36%	-25%	-2x	-15x	-	-
Cancel 1000 new	AEO (Low)	2006 +10%	Peak	36%	-26%	31%	-31%	-1x	-14x	-	-
Cancel 511 new	AEO (Low)	2006 +10%	Peak	29%	-32%	15%	-46%	-3x	-16x	-	-
No cancel	AEO (Low)	2006 +10%	Peak	23%	-39%	1%	-61%	-6x	-18x	-	-
			Base	28%	-34%	28%	-34%	-5x	-18x	-	-
Cancel 2000 new	Platts (Ref)	2006	Peak	30%	-32%	14%	-48%	-4x	-17x	-	-
			Base	22%	-39%	22%	-39%	-8x	-21x	-	-
Average of all Scenarios				**30%**	**-32%**	**24%**	**-37%**	**-4x**	**-17x**		

Four scenario results are highlighted. Of the reference cases, the case with peaking DER and cancellation of new CC capacity had the least savings. Without CHP, even NO_X emissions were higher with DER, but with CHP savings were shown in all categories. On the other hand, if old plants were retired, then net savings were high. The most damaging scenario to DER was with the peaking scenario, low gas prices, and cancellation of 2000 MW of new CC. The results show a net increase in all categories without CHP and an increase in CO_2 and SO_2 emissions even with CHP. This was likely the scenario that many have assumed when considering the benefits of DER, but only appeared with outdated assumptions on gas prices.

A key concern with DER is that while net emissions decline, emissions at the particular site may increase. In our analysis, this would only occur if the DER did not displace any thermal system production through CHP or if the displaced thermal process was lower emitting than the DER. In these situations it would be useful for regulations to recognize the overall reduction, perhaps by giving some type of credit for the central electric system emission reductions.

In conclusion, our analysis shows that even if new, gas-fired CC capacity is cancelled in proportion to the impact of DER on system loads, energy is saved and net emissions are reduced. Utilizing the exhaust heat from the DER compounds the savings and makes DER a valuable component of the country's energy portfolio.

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