The Value of Distributed Generation and Combined Heat and Power Resources in Wholesale Power Markets

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September 30, 2005

Contract 4000021799

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Introduction

Distributed generation and combined heat and power (DG/CHP) projects are usually considered as resources for the benefit of the electricity consumer not the utility power system. This report evaluates DG/CHP as wholesale power resources, installed on the utility side of the customer meter. The basic elements of utility resource planning are applied to DG/CHP projects the way a utility would evaluate conventional system resources. The intent of the report is to show utility planners and DG/CHP resource developers how these resources can be used to the advantage of the electric power system by lowering the cost of providing service to customers. Applications that have maximum value to the power system should provide the greatest return on investment to developers. The report also includes brief discussions of how DG/CHP resources might be exploited in evolving deregulated markets.

Resource planning is the process used in traditional regulated markets for determining which, when, where and how many electric power resources should be developed. The process has evolved and become increasingly complicated over the history of the power industry. Electric power resources have long development lead times and economic lives. Therefore, planning well in advance of needs is critical. The two most important planning parameters have been cost and reliability of service. Resource planning has been divided into supply and demand side resources. Supply side resources include generation, transmission and distribution assets. Demand side resources include conservation, energy efficiency, demand side management and demand response programs. Often these resources have been planned independently of one another. Demand side resources have been subtracted from load to result in a net load. Generation plants are then planned based on the size of the net load compared to existing generation resources. Transmission assets are developed to deliver the power from the generation plants to a transmission network, and then to distribute the power from the network to the major load centers. Distribution assets are developed to deliver the power the major load centers to local load centers.

Integrated resource planning recognizes that tradeoffs are possible between generation, transmission, distribution and demand side assets. DG/CHP resources have largely to date been treated as demand side assets, resources developed on the customer side of the meter that from a utility perspective result in reduced load to be served by the utility power system. This paper looks at placing DG/CHP assets on the utility side of the meter in different applications throughout the power system to lower the cost of service. Some basic examples showing how utility system resources are evaluated and planned are provided to show how DG/CHP can be compared against traditional utility generation, transmission and distribution assets.

In deregulated markets the issue of whether resources need to be planned is still being debated. Currently, the terms of discussion in deregulated markets have moved from resource planning to resource adequacy. Centralized planning is not supposed to be required in a deregulated market; when capacity becomes short prices will rise and resources will be developed. The concern is that the lag time between rising prices and new resources in operation could be a long time and consumers could suffer extreme prices in the interim. To prevent anticompetitive prices price caps are then proposed. The price caps in turn result in lack of incentive to develop new resources, so we end up with a regulated market after all. The current debate is how to design a market that provides the right incentives to efficiently develop new resources without creating opportunities for market abuse.

Resource Planning—Preliminary Considerations

New resources are added to power systems if they can economically replace or displace existing resources, when existing resources are retired, or when load growth results in insufficient capacity of existing resources. New resources have a hard time competing against existing resources because the capital cost of existing resources are sunk, and thus not counted. The capital and operating costs of new resources would have to be less than the operating costs of existing resources. Capital costs represent a major portion of the total cost of producing electricity; only when existing resources have high operating costs and new resources have low capital and operating costs can the new resources be competitive. Hence, new resources mostly compete against other new resources.

New resources are evaluated against each other using complex computer models. The models can simulate the hourly operation of the power system over long periods, twenty or thirty years. Detailed hourly loads and production costs of all of the power plants in the system are represented in the model. The production costs of the power plants are based on many detailed parameters: fuel costs, heat rates at full and partial loads, hot and cold startup and shutdown costs, rates of load change, minimum and maximum operating loads, ambient temperatures, and system imposed constraints. Transmission system load flows and losses are modeled in separate programs, which in some cases are integrated with the generation models. Distribution systems are modeled separately from generation and transmission systems. A base case model is usually developed and alternative cases are developed and compared against the base case. The case that results in the lowest net present value is the winner. Because some input assumptions, fuel costs and loads, are highly uncertain over the life of the resource assets alternative scenarios are run using a range of assumed values. Because these models are extremely complicated and take a long time to run, it is not possible to run every possible case. In order for DG/CHP plants to be considered they have to be accurately modeled and included in case runs. This is often not the case. DG/CHP is usually treated as load reduction, not as system resources that can possibly result in a least cost resource plan.

Bulk Power Resource Planning

Distributed generation and combined heat and power plants, particularly the larger ones, can be used to satisfy bulk power resource needs. This section will show how a utility resource planner would evaluate new resources, conventional and DG/CHP, for deployment in a hypothetical power system consisting of a portfolio of conventional bulk power resources.

The first step in the analysis is to evaluate the load profiles and generation resources of the existing power system. New resources are considered when loads are expected to increase to the point where existing resources no longer have sufficient capacity to serve the expected loads. New resources can also be considered against existing resources for serving existing loads. Resource planning computer models are used to determine the least cost method of serving the loads. In this report we will use a simpler and more illustrative (but of course less accurate) method based only on load duration curves and resource production costs.

Figure 1 below shows the load duration curve for our hypothetical power system. The curve is constructed by sorting one year's worth of system hourly loads in descending order. The system has a peak load of 6250 MW and a minimum, or base, load of 1000 MW.

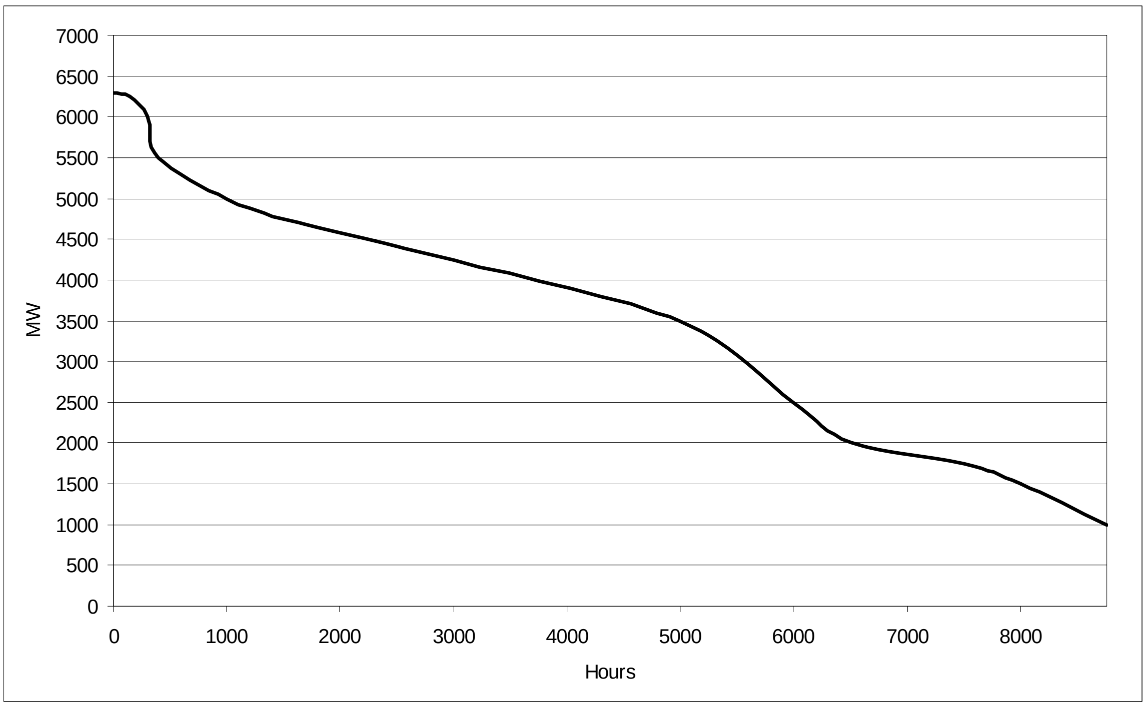

Figure 1 Load Duration Curve for Hypothetical Power System

We further assume that power system consists of the resources presented in Table 1. The system has 12 power plants of various technologies and production costs. The operating costs are based on assumed heat rates, fuel costs, and variable operating and maintenance costs. Throughout this report natural gas is assumed to cost $5 per million Btu and coal $2 per million Btu. Production costs are the sum of fuel costs and variable operating and maintenance cost. The values used in Table 1 and successive tables are typical, but should not be construed as representative of all power systems or situations. Capital and production costs depend upon many factors and can vary greatly by system and region.

The objectives of all of the examples presented throughout this report are to demonstrate the methodologies for evaluating resources and to suggest that DG/CHP resources may offer economically attractive alternatives to traditional resources for some power systems. This report is not suggesting that DG/CHP resources are always going to come out ahead of conventional resources in the example applications presented.

	MW Output	Production Cost ($/MWh)	Hours / Yr	Load Duration Curve (MW)	Power Production (MWh)	System Production Cost
NUCLEAR A	1000	20	8760	1,000	8,760,000	$175,200,000
COAL STEAM A	500	35	8000	1,500	4,000,000	$140,000,000
CTCC NG A	500	40	7000	2,500	3,500,000	$140,000,000
COAL STEAM B	250	45	6000	1,750	1,500,000	$67,500,000
COAL STEAM C	250	50	5000	2,000	1,250,000	$62,500,000
CTCC NG B	1000	55	4000	3,500	4,000,000	$220,000,000
NG Steam A	750	60	3000	4,250	2,250,000	$135,000,000
NG Steam B	500	65	1500	4,750	750,000	$48,750,000
NG Steam C	250	70	1000	5,000	250,000	$17,500,000
NG CT A	500	71	500	5,500	250,000	$17,750,000
NG CT B	500	72	250	6,000	125,000	$9,000,000
NG CT C	250	75	150	6,250	37,500	$2,812,500
Annual Total:					26,672,500	$1,036,012,500
Weighted Average Production Cost:						$39/MWH

Table 1 Power System Resources, Dispatch Order and Production Costs

The system loads are served by dispatching the power plants sequentially, starting with lowest production cost, as shown in Figure 2. This simple representation assumes the plants are perfectly dispatchable, that is they can be turned on and off at will, with no startup or shutdown costs; that they are perfectly reliable, have no planned or unplanned outage requirements, and can operate all year long if needed. In fact, power generation resources can have very different operating flexibility, reliability and maintenance characteristics that can affect power production costs and resource selections. Some of these complications will be addressed later.

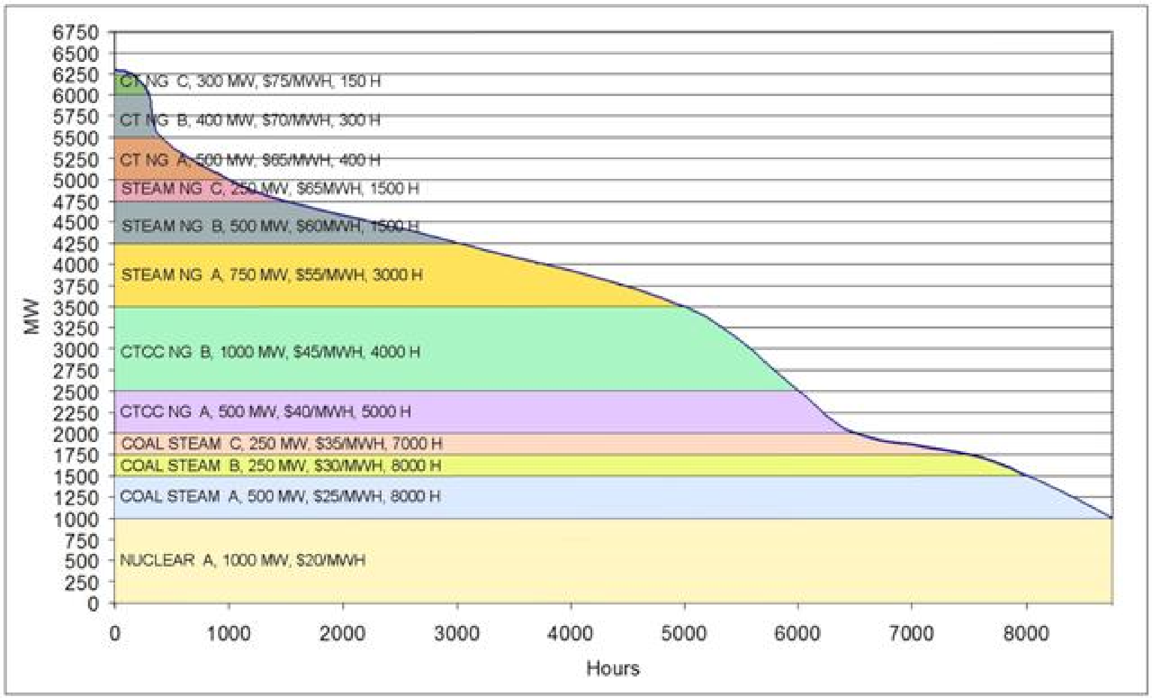

Figure 2 Sample Power System Load Duration Curve Showing Power Plant Dispatch Order by Marginal Production Costs[1]

If the power system has adequate capacity to meet existing loads, then any proposed new resources must compete on a production cost basis alone, absent any regulatory mandates, emissions limits or costs, or other circumstances. The capital costs of existing resources are sunk costs and thus not used in any comparisons with new resources. Table 2 below presents representative capital and operating costs for current bulk power options.

	Nominal Size (MW)	Capital Cost ($/kW)	Fixed Operating Cost ($/kW/yr)	Variable Production Cost ($/MWh)
Coal, Pulverized	2x400	1,243	40	37
Coal, IGCC[2]	500	1400	45	33
NG, CTCC[3]	263	565	9	36

Table 2 New Bulk Power Options. **From Reference [1] at End of Report.**

If the coal based IGCC plant were added to the system, its production cost of $32.5/MWH second lowest cost resources in the system; given our hypothetical system load duration curve the IGCC plant would dispatched for 8000 hours per year. Again, downtime for maintenance and forced outages are ignored in this simple example. The new loading order and production costs would be as follows.

[1] The load duration curve in the simple example is actually should look like a staircase; it is drawn with smooth curves to more closely resemble the curves for real power systems.
[2] IGCC = Integrated Gasification Combined Cycle—a combustion turbine fueled by gasified coal with a heat recovery steam generator feeding steam turbine bottoming cycle.
[3] CTCC = Combustion Turbine Combined Cycle.

	MW Output	Production Cost ($/MWh)	Hours / Yr	Load Duration Curve (MW)	Power Production (MWh)	System Production Cost
NUCLEAR A	1000	20	8760	1,000	8,760,000	$175,200,000
New Coal IGCC	500	33	8000	1,500	4,000,000	$132,000,000
COAL STEAM A	500	35	7000	2,000	3,500,000	$122,500,000
CTCC NG A	250	40	6000	2,250	1,500,000	$60,000,000
CTCC NG A	250	40	5000	2,500	1,250,000	$50,000,000
COAL STEAM B	250	45	4000	2,750	1,000,000	$45,000,000
COAL STEAM C	250	50	4000	3,000	1,000,000	$50,000,000
CTCC NG B	500	55	4000	3,500	2,000,000	$110,000,000
CTCC NG B	500	55	3000	4,000	1,500,000	$82,500,000
NG Steam A	250	60	3000	4,250	750,000	$45,000,000
NG Steam A	500	60	1500	4,750	750,000	$45,000,000
NG Steam B	250	65	1000	5,000	250,000	$16,250,000
NG Steam B	250	65	500	5,250	125,000	$8,125,000
NG Steam C	250	70	500	5,500	125,000	$8,750,000
NG CT A	500	71	250	6,000	125,000	$8,875,000
NG CT B	250	72	150	6,250	37,500	$2,700,000
NG CT B	250	72	0		-	$-
NG CT C	250	75	0		-	$-
				Total	26,672,500	$961,900,000
					Average Production Cost:	$36.1
					Annual Savings Due to New IGCC Plant:	$74,112,500
					Annual Savings Per KW of IGCC Plant Capacity:	$148/kW/yr

Table 3 Power System Dispatch, Production Costs and Savings With New IGCC Plant

The value of the IGCC plant in the traditional regulated environment equals the difference in system operating costs with and without the IGCC plant. If the net present value of the operating cost savings is greater than the present value of the capital cost of the new plant, then it is economically justified. The difference in system operating costs with and without the new IGCC plant is $74,112,500 per year, or $148/kW/yr when divided by the 500 MW of plant capacity. A simple payback on the capital cost of the plant can be calculated after subtracting 45$/kW/yr of fixed operating costs and assuming equal savings each year:

> **Payback Period = $1400/kW / $103/kW/yr = 14 years.**
> **[Regulated Market, Excess System Capacity]**

Neither a regulated utility nor a merchant plant developer would use a simple payback analysis to determine whether to build a plant or not. Rather, they would use a net prevent value analysis, which would require estimates of the annual costs and savings over the lifetime of the plant. The costs and savings would then be discounted to the present for comparison with the initial capital investment. The payback analysis presented here provides a simple, first order estimate of project value. An investment having a fourteen year simple payback is not likely to be made by either a regulated utility or a merchant generator. This simple example demonstrates the previously mentioned point that new plants are difficult to justify on operating cost savings alone. Capacity shortages due to load growth or plant retirements are usually needed before new plants can be economically viable.

Economic viability for a new plant operating in a deregulated market is calculated differently. The revenue generated by the new IGCC plant would be determined by the hourly marginal system costs during the periods in which the IGCC plant operates. The hourly marginal system costs are based on the highest operating cost of a plant operating in that hour, i.e., the cost of the last dispatched plant. The revenue is calculated as shown in Table 4.

	MW Output	Production Cost ($/MWh)	Hours / Yr	Load Duration Curve (MW)	Hours on Margin	IGCC Revenue
Nuclear A	1000	20	8760	1,000	760	
New Coal IGCC	500	33	8000	1,500	1000	$16,500,000
Coal Steam A	500	35	7000	2,000	1000	$17,500,000
CTCC NG A	250	40	6000	2,250	1000	$20,000,000
CTCC NG A	250	40	5000	2,500	1000	$20,000,000
Coal Steam B	250	45	4000	2,750	0	$-
Coal Steam C	250	50	4000	3,000	0	$-
CTCC NG B	500	55	4000	3,500	1000	$27,500,000
CTCC NG B	500	55	3000	4,000	0	$-
NG Steam A	250	60	3000	4,250	1500	$45,000,000
NG Steam A	500	60	1500	4,750	500	$15,000,000
NG Steam B	250	65	1000	5,000	500	$16,250,000
NG Steam B	250	65	500	5,250	0	$-
NG Steam C	250	70	500	5,500	250	$8,750,000
NG CT A	500	71	250	6,000	100	$3,550,000
NG CT B	250	72	150	6,250	150	$5,400,000
NG CT B	250	72	0		0	$-
NG CT C	250	75	0		0	$-
				Total:	8760	$195,450,000

Table 4 IGCC Revenues in Deregulated Market

The total revenues for the IGCC plant would be $195,450,000 per year or $391/kW per year for the 500 MW of IGCC plant capacity. Subtracting the $45/kW/yr fixed operating cost and assuming the annual savings are constant over the life of the plant results in a simple payback of four years:

Payback Period = $1400/kW / $346/kW/yr = 4 years.
[Deregulated Market, Excess System Capacity]

For our hypothetical power system, in which we have currently assumed that new resources have no capacity value, the return on investment is much faster in a deregulated market than in a regulated market. As will be discussed below, in regulated markets when system capacity is short new resources are given capacity credit. In deregulated markets, there is no explicit added value for capacity for bulk power resources[4]; economic theory suggests that paying all plants the marginal system cost will provide enough incentive, or capacity value, to develop new resources. This theory is still being debated and some deregulated markets are considering adding capacity value or creating a market for new capacity.

CHP as a Bulk Power Resource

CHP options can be very competitive with conventional bulk power resources. Table 5 below presents typical cost and performance characteristics of CHP resources. The key advantage to CHP projects is their low effective heat rate, often called a fuel chargeable to power (FCP). FCP is calculated by subtracting the value of the heat produced by the CHP plant from the simple heat rate of the CHP plant. The value of the heat is calculated based on what it would have cost to generate the heat in the absence of the CHP plant.

For example, consider the energy balance of the generic CHP device shown in Figure 3 below. One kW of fuel input produces 0.3 kW of electricity and 0.5 kW of useful heat for an overall efficiency of 80%. The simple heat rate is 1 kW *3412 Btu/kWh fuel / 0.3 kW = 11, 373 Btu/kWh. If the 0.5 kW of recoverable heat were produced by a conventional heat generating device, *e.g.*, a hot water heater, a furnace or a steam boiler, the fuel consumed by the heat generating device would be 0.5 kW divided by its efficiency. This report has taken a conservative approach to calculating FCP by assuming an efficiency of 100% for the heat generating device. (The less efficient the heat generating device being replaced by the CHP plant, the more valuable the heat from the CHP plant.) The FCP in Figure 3 is thus calculated by subtracting the fuel value of the recoverable heat from the actual fuel input and dividing by the electric output: FCP = (1.0 – 0.5) kW * 3412 Btu/kWh Fuel / 0.3 kW Electricity = 5687 Btu/kWh.

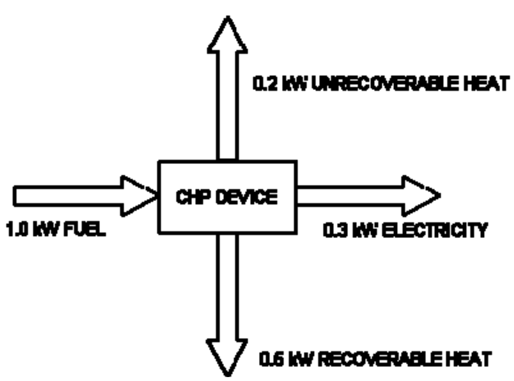

Figure 3 Energy Balance for a CHP Device

[4] Reserve resources, which are intended only to operate to balance short term supply demand imbalances, and to replace scheduled resources that fail to operate, are currently given capacity value in deregulated markets.

	Nominal Size (MW)	Heat Rate (Btu / kWH HHV)	Recoverable Heat (Btu / kWH LHV)	Fuel Charge to Power (Btu / kWh HHV)	Capital Cost ($/kW)	Total Variable Cost ($/MWH)
CT NG AERO CHP	22	10,412	4,135	6,276	950	43.26
CT NG AERO CHP	44	9,334	3,120	6,213	700	39.82
CT NG CHP	77	10,736	4,600	6,136	650	38.80
CT NG CHP	172	10,362	4,275	6,087	600	37.94
ICE NG 8000+ h/y CHP	1.3	9,350	3,497	5,853	766	44.26
Microturbine CHP	.060	13,404	6,562	6,843	1,500	49.21

Table 5 CHP Resource Options

Now consider a new 77 MW combustion turbine based CHP plant from Table 5 as a bulk power resource in the hypothetical power system. The plant has a capital cost of $650/kW, a FCP of 6136 Btu/kWh and an operating cost of $38.8/MWH. It will be dispatched right after the coal plant and thus will operate up to 7000 hours per year.

	MW Output	Production Cost ($/MWh)	Hours / Yr	Load Duration Curve (MW)	Power Production (MWh)	System Production Cost
NUCLEAR A	1000	20	8760	1,000	8,760,000	$175,200,000
COAL STEAM A	500	35	8000	1,500	4,000,000	$140,000,000
CT CHP 6F	**77**	**38.8**	**7000**	**1,577**	**539,000**	**$20,913,200**
CTCC NG A	423	40	7000	2,000	2,961,000	$118,440,000
CTCC NG A	77	40	6000	2,077	462,000	$18,480,000
COAL STEAM B	173	45	6000	2,250	1,038,000	$46,710,000
COAL STEAM B	77	45	5000	2,327	385,000	$17,325,000
COAL STEAM C	173	50	5000	2,500	865,000	$43,250,000
COAL STEAM C	77	50	4000	2,577	308,000	$15,400,000
CTCC NG B	923	55	4000	3,500	3,692,000	$203,060,000
CTCC NG B	77	55	3000	3,577	231,000	$12,705,000
NG Steam A	673	60	3000	4,250	2,019,000	$121,140,000
NG Steam A	77	60	1500	4,327	115,500	$6,930,000
NG Steam B	423	65	1500	4,750	634,500	$41,242,500
NG Steam B	77	65	1000	4,827	77,000	$5,005,000
NG Steam C	173	70	1000	5,000	173,000	$12,110,000
NG Steam C	77	70	500	5,077	38,500	$2,695,000
NG CT A	423	71	500	5,500	211,500	$15,016,500
NG CT A	77	71	250	5,577	19,250	$1,366,750
NG CT B	423	72	250	6,000	105,750	$7,614,000
NG CT B	77	72	150	6,077	11,550	$831,600
NG CT C	173	75	150	6,250	25,950	$1,946,250
				Total	26,672,500	$1,027,380,800
					Weighted Annual Average Production Cost	$39/MWH

Annual Power System Savings Due to New 77 MW CHP Plant:	$8,631,700
Annual Savings Per kW for the 77 MW CHP Plant:	$112

Table 6 System Dispatch, Production Costs and Savings with New CHP Plant

The difference in system operating costs with and without the new CHP plant is $8,631,700 per year, or $112/kW/yr of new plant capacity. This represents, after subtracting $6/kW/yr fixed operating costs, and assuming equal savings each year, a simple payback of $650/kW / $106/kW/yr = 6 years, which could be cost effective in a regulated utility market or for some project developers.

The revenues for the CHP plant in a deregulated market are calculated in Table 7 below, in the same way as the IGCC example above. The annual revenues are $29,544,900 or $383.7/kW per year. The payback is $650/kW / $378/kW/yr = 1.7 years. This is a very attractive payback and suggests that CHP resources having low capital cost and good thermal output utilization should be among the first resources considered for development in any power system.

	MW Output	Production Cost ($/MWh)	Hours / Yr	Load Duration Curve (MW)	Hours On Margin	CHP Revenue
NUCLEAR A	1000	20	8760	1,000	760	
COAL STEAM A	500	35	8000	1,500	1000	
CT CHP 6F	77	38.8	7000	1,577	0	
CTCC NG A	423	40	7000	2,000	1000	$3,080,000
CTCC NG A	77	40	6000	2,077	0	$-
COAL STEAM B	173	45	6000	2,250	1000	$3,465,000
COAL STEAM B	77	45	5000	2,327	0	$-
COAL STEAM C	173	50	5000	2,500	1000	$3,850,000
COAL STEAM C	77	50	4000	2,577	0	$-
CTCC NG B	923	55	4000	3,500	1000	$4,235,000
CTCC NG B	77	55	3000	3,577	0	$-
NG Steam A	673	60	3000	4,250	1500	$6,930,000
NG Steam A	77	60	1500	4,327	0	$-
NG Steam B	423	65	1500	4,750	500	$2,502,500
NG Steam B	77	65	1000	4,827	0	$-
NG Steam C	173	70	1000	5,000	500	$2,695,000
NG Steam C	77	70	500	5,077	0	$-
NG CT A	423	71	500	5,500	250	$1,366,750
NG CT A	77	71	250	5,577	0	$-
NG CT B	423	72	250	6,000	100	$554,400
NG CT B	77	72	150	6,077	0	$-
NG CT C	173	75	150	6,250	150	$866,250
					8760	$29,544,900

Table 7 CHP Revenues in Deregulated Market

These two examples, the IGCC and the CHP plants, showed how new resources would be evaluated against existing resources. The new resources would be dispatched according to their marginal production costs. The lower the production cost the more hours the plant will be dispatched. In a traditional regulated market the new plant will be built if the savings in system operating cost are enough to justify the capital cost of the plant. In the evolving deregulated markets the new plant would be built if it can generate enough revenue to provide an adequate return on the capital cost of the plant. The revenue generated is determined by the system marginal operating costs during the periods that the new plant operates. In either regulated or deregulated worlds the economic return on a new resource depends on the operating costs of the existing system resources. The second example showed a case where a low cost CHP plant in which most of its thermal output it economically utilized can compete against existing base-load resources on operating costs alone.

The examples above showed in simplified fashion how new resources would be evaluated in a hypothetical power system. Real power systems are much more complicated, as is the modeling and analysis of new resources. A typical utility model would simulate many system operating details not considered here, such as:

- detailed hourly dispatches of each generator
- fuel prices, operating costs and loads projected into future years, often up to 30 years
- power plant operating constraints and characteristics, e.g., hot and cold startup and shut down times and costs, part load efficiencies, allowable rates of load changes, degradation of output and efficiency over time, temperature and elevation effects on output and efficiency, maintenance schedules, forced outage rates, effects of cycling on maintenance costs
- system operating constraints, such as voltage limits, transmission limits, reserve margin requirements
- power transfers to and from adjacent power systems
- purchased power obligations, *e.g.,* from PURPA/QF/CHP plants
- operating constraints or advantages from renewable and hydro/storage resources
- the effects of multiple resource additions in the future

The simplified examples above are, nevertheless, reasonable starting points for estimating the economic feasibility of new resources in regulated and regulated markets.

Evaluation of Small DG/CHP Plants Using Incremental or Avoided Costs

The two examples above showed that even relatively simple analyses of power system economics can become complex. Addition of one plant can change the dispatch times of all other plants in the system that have higher operating costs. Because it would be too costly and complex to run production cost models for every proposed DG/CHP (and energy efficiency) project, utilities often use the method of marginal avoided costs, also called system power values, for evaluating small resource additions. The marginal costs are generated by the system production cost models. The models calculate the incremental cost of producing another kW for each hour of the year over a range of years. The costs are then sorted in descending order, just as the loads are in a load duration curve. The value of the electricity generated by a resource is determined by the hours that the resource operates. A perfectly dispatchable resource that can operate for 8000 hours per year would receive credit for the 8000 hours of the year having the highest electricity value. Tables of electricity value vs. dispatchable hours, or fractions of the load duration curve, are generated, such as is shown in Table 8 below. The table also shows capacity values, which will be discussed in a section below. The total value of electricity is the sum of the energy and capacity values. Resources that are not dispatchable have to use an hourly production cost model to determine the value of electricity during the specific hours that the resource operates. If a resource is non-dispatchable and its operating hours are unpredictable, then it is assumed to have the lowest possible energy value, and no capacity value. Non-dispatchable resources generally cannot claim capacity credits unless some correlation can be shown between the hours they operate and the peak system hours.

Load Duration Curve	Value of Energy $/MWh	Value of Capacity $/MWh
100%	20	2
90%	22	2.2
80%	30	2.3
70%	35	2.3
60%	40	2.4
50%	45	3
40%	50	4
30%	60	5
20%	70	10
10%	80	20
5%	100	40

Table 8 Power System Marginal Costs

One can easily see how to generate a table of system marginal costs similar to Table 8 above for our hypothetical power system. For instance, working from the bottom of Table 9, below, the energy produced by a resource that operates between 0 and 150 hours is $75/MWH. If the resource operates for 160 hours, the value is [(150x75)+(10x72)]/160= $74.8125/MWH. In this manner a table can be generated for all 8760 hours.

These tables can be used by utility resource planners to compare resource options. Even though no resource is perfectly dispatchable this type of analysis allows for comparisons among options that have similar characteristics. Resources are less than perfectly dispatchable because they are not 100% reliable, and it takes time and costs money to start and stop them. Resources are also unavailable during maintenance outages. Planned maintenance is scheduled during off-peak periods when the power is expected to have the least value.

Rather than generate a table of avoided costs for our hypothetical power system we can say that the revenues calculated from such a table would be equal to the revenues calculated following the deregulated market examples above. Consider a 1 MW internal combustion reciprocating engine (ICE) having a fuel chargeable to power of 5800 Btu/kWh, a capital cost of $800/ kW and a total operating cost (natural gas fuel and variable O&M) of $44/MWH. The value of the wholesale power from the unit would be equal to production cost of the marginal generation units operating in the power system when the ICE is operating. The results are shown below in Table 9, where the ICE is virtually dispatched after the CTCC NG A plant.

	Production Cost ($/MWh)	Hours / Yr	Hours on Margin	Marginal Revenue $/MWh	Operating Hours for ICE	Revenue for ICE
NUCLEAR A	20	8760	760	$15,200	0	0
COAL STEAM A	35	8000	1,000	$35,000	0	0
CTCC NG A	40	7000	1,000	$40,000	0	0
COAL STEAM B	45	6000	1,000	$45,000	1000	$45,000
COAL STEAM C	50	5000	1,000	$50,000	1000	$50,000
CTCC NG B	55	4000	1,000	$55,000	1000	$55,000
NG Steam A	60	3000	1,500	$90,000	1500	$90,000
NG Steam B	65	1500	500	$32,500	500	$32,500
NG Steam C	70	1000	600	$42,000	600	$42,000
NG CT A	71	400	100	$7,100	100	$7100
NG CT B	72	300	150	$10,800	150	$10,800
NG CT C	75	150	150	$11,250	150	$11,250
		Total	8,760	$433,850	6000	$34,3650
			Weighted Average	$49.53/MWh		$57.275/MWh

Table 9 Value of Energy Produced by a Reciprocating Engine

Because the operating cost of the ICE is $44/MWH it should only operate when the avoided cost is higher than 44; which corresponds to 6000 hours of operation at a weighted average revenue of $57.3/MWH. This is the most profitable operating scheme for the ICE CHP unit for generating wholesale electricity. Operation outside of these 6000 hours when avoided cost is less than the production cost means the unit would be losing money during those hours. A common mistake among DG/CHP developers is to try to maximize the capacity factor of their resource, assuming that the lowest COE is the objective. The real objective is to maximize the profitability of the resource by maximizing its operation during profitable hours, not all hours.

The operating requirements necessary to dispatch a unit only during profitable hours may, however, be impractical. Capturing only the profitable operating hours might require shutdowns on nights or weekends. Perfect dispatchability is difficult to achieve in practice, although a reciprocating engine is much easier to shut on and off than other power generation equipment. CHP units have to satisfy both electric and thermal load requirements. The thermal load requirements may force the CHP unit to operate during unprofitable electricity generating times. Even if the engine itself can by cycled on and off as needed to maximize electric production profitability, the heat recovery equipment is not as easy as not as easy to cycle. Some industrial plants, such as oil refineries, paper mills, steel mills and breweries, have large base thermal loads that are ideal for CHP projects. Commercial loads, on the other hand, are not as steady, with electric and thermal loads varying continuously, and not always in synchronization with each other. In these less than ideal applications not all the available heat from the power generation device can be utilized, so the effective FCP is a fraction of the theoretical FCP.

The Value of Capacity

The previous examples have assumed that our hypothetical power system has adequate capacity. When the system is short of capacity, new resources have greater value, in either regulated or unregulated markets. In a regulated market the system is assumed to need a certain excess capacity or reserve margin. When the reserve margin becomes too small the utility develops new resources (supply or demand side) to bring it back to the right level. Alternative resources are compared in the resource planning models and the resources that satisfy all system requirements and have the lowest net present value are selected for development. The capital costs of the resources are then added to the utility rate base and recovered according to standard regulatory practice with an allowed rate of return on capital.

Utilities may consider DG/CHP resources along with other alternatives for addition to the system and the rate base. Wholesale DG/CHP resources developed by third parties would be treated by a utility as purchased power, which would be paid an avoided cost based on what resources the utility would have developed if purchased power were not available. The avoided cost of energy is determined as discussed in the examples above. The avoided cost of capacity is based on a resource having the lowest capacity cost, which usually means a simple cycle combustion turbine. Even though a utility that needs capacity may install a higher cost base load resource, and not a combustion turbine, the value of the capacity of that resource is never greater than that of the combustion turbine (or lowest cost resource). The incremental capital cost of the base load resource relative to the combustion turbine would have to be justified based on operating cost savings to the system relative to the system with a new combustion turbine.

In a deregulated market every plant is the system benefits when generation capacity is short. This is because marginal operating costs will increase during the peak periods (unless the market has capped prices or somehow always limits marginal prices to marginal costs by rule). Every plant owner gets some incentive to build a new plant whether a new plant is built or not.

In actuality a new resource is only credited with a fraction of the theoretical maximum value. First, the capacity of the resource is reduced by its unreliability. For example a 100 MW combustion turbine that has a forced outage rate (FOR) of 5% (equivalent to a reliability of 95%) would only get credit for 95 MW of capacity to account for the 5% probability that the resource would not be available during the peak period when it is needed. Secondly, the capacity value is reduced in proportion to actual system reserve margin relative to the desired reserve margin. The lower the actual reserve margin the greater the fraction of maximum capacity value a resource is credited.

The ideal system reserve margins have historically been based on system loss of load probability (LOLP) calculations. LOLP is the probability of not being able to serve load in a given hour based on the size of the load, the capacity of all resources available at that hour, and the probabilities of losing any of the resources. Industry resource planners and economists have assumed that an optimal system LOLP exists when the incremental cost of serving load equals the incremental loss of not serving the load, that is, marginal cost equals marginal revenue. At one time the lost marginal revenue, also called the cost of unserved energy or load, was based on the revenue that the utility would not collect if the system was down. More recently the cost of unserved energy has been based on an assessment of the losses that electricity consumers would experience if their electricity were cut off. Surveys were conducted of various end users to determine the dollar cost to consumers of power outages. These methods are somewhat arbitrary because the value of unserved energy varies considerably by customer served, and because asking a customer how much an outage costs is not likely to result in the same value as how much they would actually pay to avoid an outage. The amount they would pay better reflects the economic cost of system capacity. Utilities have often simplified the problem by using a proxy of one day (24 hours) of outage per 10 years of service as the optimal level of reliability. This translates to a LOLP of 0.000274, or a system reliability of 99.973%. A utility would then typically allocate the cost of a combustion turbine to the peak hours in the year in proportion to the unreliability of the system in those hours. For example, if a combustion turbine costs $400/kW, a utility has a capital recovery factor of 0.15$/$/yr and the calculated LOLP factors for the top 10 peak hours on the system are as shown Table 10 below, then the capacity values during those peak hours can be calculated. The values are as shown in the far right column.

Hour	LOLP	Unserved Hours / Year	Fraction of Total Unserved Hours	Capacity Value $/kWh
1	0.000274	2.400	0.168719	10.1232
2	0.000250	2.190	0.153941	9.2365
3	0.000225	1.971	0.138547	8.3128
4	0.000200	1.752	0.123153	7.3892
5	0.000175	1.533	0.107759	6.4655
6	0.000150	1.314	0.092365	5.5419
7	0.000125	1.095	0.076970	4.6182
8	0.000100	0.876	0.061576	3.6946

9	0.000075	0.657	0.046182	2.7709
10	0.000050	0.438	0.030788	1.8473
Total	0.001624	14.226	1.000000	60.0000

Table 10 Value of Capacity in Top Ten Peak System Hours

This table is usually extended beyond 10 hours to the point where the LOLP drops off such that the capacity value becomes negligible. The LOLP values shown in the table were made up for the example; in a real power system they would be calculated for the specific loads and power plants operating during each hour.

Deregulated markets still generally using the same reserve margin and system reliability criteria as regulated markets, but there is some discussion about letting the market decide how much capacity is needed. This would be possible when consumers are exposed to real time prices that reflect capacity shortage. Deregulated markets in the U.S. currently have not done away entirely with capacity values; they have developed separate markets for energy and reserves. The reserve markets pay capacity prices, the energy markets do not. The bulk of the power supplied in any given day is supposed to come from the energy market, with the reserve markets providing regulation, load balancing, spinning reserve and replacement reserves. Some market researchers have suggested that reserve markets may not needed and are economically inefficient. The high energy prices available during capacity shortage periods are sufficient incentives for resources to be held in reserve, and the probability of a system outage due to insufficient reserves will be small when consumers are also exposed to the high instantaneous prices and thus demand is likely to decline rapidly with high prices.

The Potential for Smaller DG/CHP Resources to Reduce System Operating Costs

In the previous examples the power plants were assumed to be perfectly dispatchable and full load heatrates were used to calculate operating costs. In reality power plants are often cycled up and down in load (with higher heat rates than at full load), and are run during off-peak times even though lower cost resources are available. Less efficient plants might be run during off peak periods due to system operating constraints or because the time and cost of turning them on and off makes that impractical. Smaller DG/CHP resources have an opportunity to save system operating costs by being utilized for load following duty; they can be more easily turned on and off and located closer to load centers to support system voltage requirements.

To get a sense of power plant cycling requirements in a typical power system Figure 4 shows an hourly profile for a summer day in the power system controlled by the California Independent System Operator (ISO). Other power systems have similar shapes.

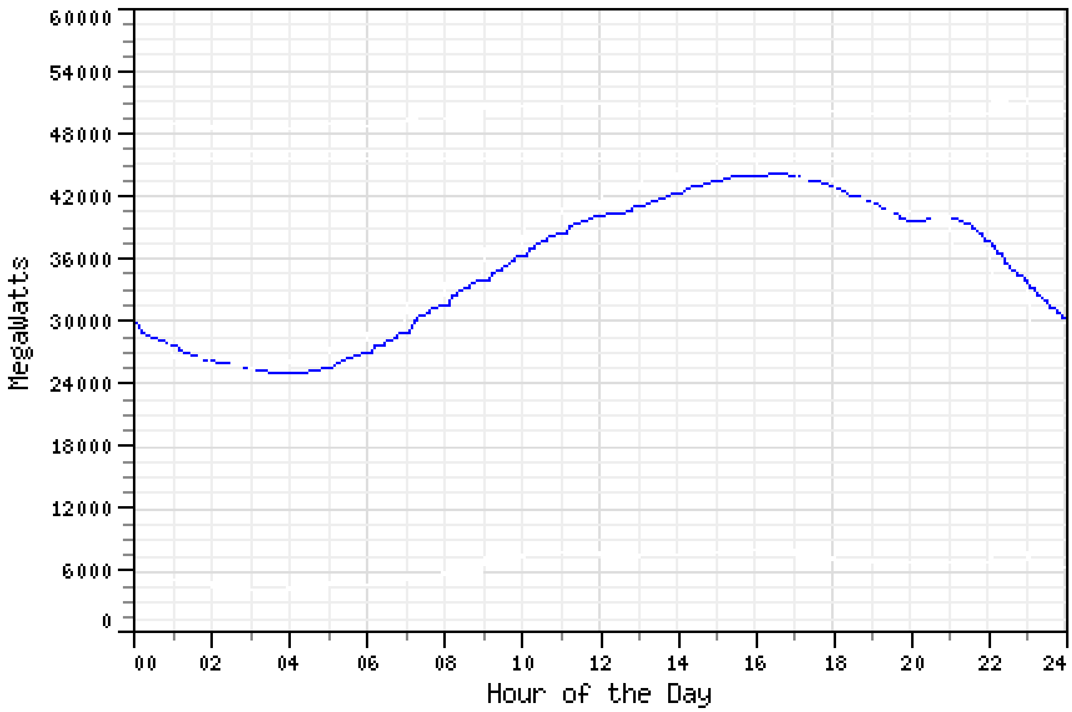

Figure 4 Hourly Electric Power System Load Profile (From CAISO web site; data for Tuesday, July 19, 2005)

Note that the peak load of 45,000 MW is close to twice the minimum load of 25,000 MW, and that the average hourly load change from minimum to peak is 1600 MW. The maximum rate of change over an hour is about 2300 MW. Approximately half the power plants in the system are either cycled from minimum to maximum to minimum output each day, or else completely turned on and off. Simple cycle combustion turbines are usually turned on and off, and everything else is usually cycled. Cycling causes a lot of wear and tear and results in less than optimal fuel efficiency in the plants. The system operator must determine the optimal resource loading sequence that results in minimum production costs over each daily cycle. This optimization looks at not just the full load efficiencies, but the partial load efficiencies, the cold startup and hot standby costs and other factors. Old steam plants having much lower efficiency than current state-of-the-art combined cycle plants do a lot of the cycling duty in power systems throughout the U.S. Higher fuel prices may accelerate the retirements of these old plants.

DG/CHP plants have the potential to reduce system operating costs. For example, consider a 180 MW steam plant having minimum production cost of $75/MWH at full power, a minimum load of 45 MW, a minimum load production cost of $125/MWH and an operating schedule of 8 hours at full load and 16 hours at minimum load. The unit is needed for only 8 hours a day but is kept on line all day because of voltage limits on the power system and so that it remains hot for the next day. Let us consider replacing the old steam plants with four 45 MW high efficiency, simple cycle aeroderivative combustion turbines having an operating cost of $54/MWH and a capital cost of $600/kW. The operating cost comparison is summarized below.

Production Cost for Old Steam Plant

16H/day x 45 MW x $125/MWH =	$90,000/day
8H/day x 180 MW x $75/MWH =	$108,000/day
Total:	$198,000/day

Production Cost for Four New Aero-CT Units

16H/day x 45 MW x 54 =	$38,880/day (one unit operating)
8H/day x 180 MW x 54 =	$77,760/day (four units operating)
Total:	$116,640/day

Savings due to New Aero-CT Units: $81,360/day

If these load conditions exists all year, then savings for 365 days would be:

Annual Savings: $29,696,400/yr or $165/kW/yr

Simple Payback: $600/kw /164/kW/yr = 3.6 years

This example assumed the same amount of power is produced with the old and the new plants. If power is only needed during 8 hours a day, then the savings are even greater. This is a reasonable payback in either case and suggests that this potential for operating cost savings is worth being investigated.

Additional savings are possible by strategically placing DG/CHP units near critical load centers to relieve transmission and distribution constraints, as described below. Retiring old, inefficient plants and replacing them with newer and more efficient units reduces emissions and lowers the overall demand and therefore price for fuel, which benefits all consumers. The renewables / energy efficiency community has calculated the benefits of overall fuel demand reduction (by replacing existing fossil generation with renewables or end-use efficiency measures) using macroeconomic supply-demand curve analysis [27]. This argument can be equally applied to fuel savings from using more efficient generation resources. Of course reducing fuel demand in one market, electricity generation, may merely result in increased demand in another market, so the actual savings may be difficult to measure or capture.

The Value of Location: Transmission Costs, Losses and Constraints

In the previous examples transmission costs, losses and constraints were not considered in the economic evaluation of resources. In reality these factors can have a great impact on the cost of delivered electricity. The cost of transmission lines and network upgrades necessary to connect a generation plant to the bulk power network should be included in resource comparisons[5]. Large plants that have to be located near fuel sources (*e.g.*, low rank coal) or cooling sources (*e.g.*, lakes, rivers, oceans) may incur added costs of long

[5] The cost of fuel delivery also should be included in the comparisons, but it ignored in this report.

transmission lines and energy losses from those lines. There can be considerable public opposition to new large plants and long transmission lines. Smaller plants are generally easier to site near load centers. On-site DG/CHP plants, for example, can be installed with minimal visual impact to the public. Strategically sited DG/CHP resources can reduce or defer the need for new transmission lines, can relieve bottlenecks in existing lines, and can result in less energy loss due to long distance transmission. The evolving deregulated market for electricity is beginning to quantify value of the location of generation resources through the application of locational marginal prices for electricity.

Consider a bulk power network consisting of multiple generation plants and load centers, and a high voltage transmission network interconnecting them, as shown in Figure 5. "G" represents a generation plant and "L" a load center. The cost of connecting a new plant to the network depends on the length of the line between the plant and the network. G1 requires a longer and presumably more costly transmission link than G2. Transmission lines can add significant costs, \$500-\$1000/kW or higher. The location on the network where the new plant is connected is another consideration. For instance, a plant connected at G4 might require more upgrades to the network to allow the power to flow to the load centers, than a plant at G2. Similarly the location of load centers with respect to the network, e.g., L1 vs. L2, can result in different transmission costs—a longer transmission line from the network to the load center, for instance, or a different level of network reinforcement to take load off the network.

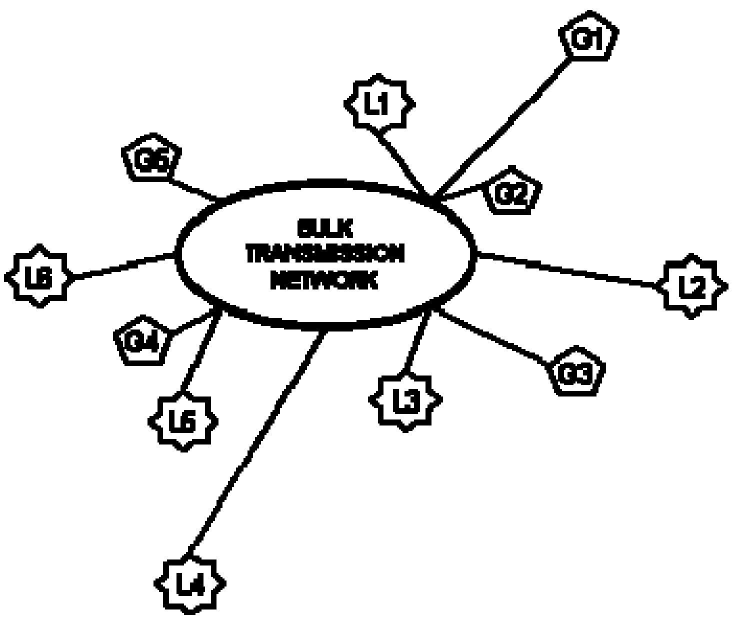

Figure 5 Bulk Power and Transmission Network.

In regulated markets the costs of delivering power from a new generation resource to the bulk power network is often taken into consideration when comparing generation options. The differences in costs of serving loads in different areas, however, are largely ignored. Every customer in a given class (usually defined by service voltage level) within a single utility, and having the same load profile pays the essentially the same price for electricity, even though the cost of service may vary by location. When these locational differences in cost are unknown or ignored, it is not likely that efforts will be made to evaluate alternative solutions to serving high cost load centers. In deregulated markets where costs of service are becoming more transparent it is likely that customers in higher cost of service areas will eventually pay higher costs. New retail providers (also called load serving entities) will choose to serve lower cost loads, or else make sure that higher costs are covered by higher prices. In the long run prices that reflect costs will be more equitable for consumers in lower cost regions and more economically efficient in higher cost areas because the higher costs will stimulate efforts to find alternative approaches, such as DG/CHP.

New construction and upgrades of transmission lines are becoming increasingly difficult or costly in the U.S due to public opposition. Many communities are requesting that transmission lines be placed underground, which can cost $3 million per mile or more. As long as these costs are spread among all consumers, as they typically are in regulated markets, they will not be readily apparent and will continue to be incurred. If electricity prices evolve to more accurately reflect costs, on the other hand, and some communities start seeing higher prices, then there will be pressure to search for lower cost alternatives. DG/CHP resources may become an attractive alternative due to lower cost and less visual and land use impact than the transmission lines. Regulated markets may not want to change current pricing structures, but could address regional cost differences by providing greater incentives to reduce loads in higher cost areas. The incentives could be made available to consumers, third parties or the utility. The economic benefit from using DG/CHP to defer or avoid investment in transmission or distribution lines is discussed below.

Using DG/CHP to Defer or Avoid Transmission Upgrades

An example above on system operating flexibility suggested that using smaller, strategically located DG/CHP plants could enable the retirement of older, inefficient steam plants. An extension of this concept is to use these smaller DG resources to defer or avoid system transmission upgrades. The capital costs of a transmission line can be so high that being able to defer the investment cost has significant economic value.

Suppose that the transmission line serving load center L2 in Figure 5 is reaching its capacity, and the load continues to grow. The length of the line from the network connection is 20 miles. A new transmission line upgrade is estimated to cost $1 million per mile and would increase the capacity of the line by 50 MW. The load is growing at a rate of 4 MW per year and the transmission capacity will be exceeded in two years. As an alternative to upgrading the transmission line consider placing a generator at L2 instead. The generator has a capacity of 20 MW and a cost of $600/kW.

Because a single generator will have lower reliability than the transmission line upgrade, we will assume in this example that the generator would be used to defer the transmission investments, not avoid them. The value of deferring a capital investment is based on a simple time value of money calculation. The value of deferral is driven by the fact that generation investments can be made in smaller increments to better match load growth than transmission (or distribution) investments, and that the cost per kW for generation resources can be equal or lower than for transmission resources.

In this example the transmission line investment has a capacity of 50 MW; with a load growth of 4 MW/yr it will take 12 years before the transmission investment will be fully utilized. In theory one could add a 4 MW generator every year to perfectly match the load growth. One could also adjust the size of the yearly generator installments to match the actual load growth if the 4 MW/yr estimate turns out be wrong. Or, one could replace the 4 MW generator installed in year 1 with an 8 MW unit in year two and so on for succeeding years until the load has grown enough to justify the 50 MW transmission line investment. Generation units would be constantly redeployed to other locations through out the power system. These types of analyses and other variations have been performed by the distributed generation research community for many years. In order to keep the analysis simple, however, we will determine the deferral benefit from using a single generator.

The 20 MW generator is able to defer the transmission investment for 5 years. The value of the deferral equals the difference in net present value between a base case transmission line investment versus an alternate case using a generator and a deferred transmission investment. Assume that the generator has a 20 year life and a salvage value at the end of the 5 years of deferral of 75 percent of its original cost, minus 5 percent for decommissioning. Also assume that inflation is zero. The cash flows for the two cases would be as shown below.

Transmission Upgrade Cost
20 miles x $1,000,000/mile = $20,000,000

Combustion Turbine Cost
20,000 kW x $600/kW = $12,000,000

Salvage Value of Combustion Turbine in Year 5
(.75-.05) x 12,000,000 =$8,400,000

Year	Case A Transmission Upgrade	Case B Combustion Turbine, Transmission Upgrade in Year 5
0	$20,000,000	$12,000,000
1		
2		
3		
4		
5		$20,000,000 - $8,400,000 = $3,600,000

Table 11 Cash Flows for Transmission Line Deferral Example

Using a time value of money of 10%, (also called discount rate or weighted cost of capital) the net present values (NPVs) are:

$$\mathbf{NPV_A = \$20{,}000{,}000}$$

$$\mathbf{NPV_B = \$12{,}000{,}000 + 3{,}600{,}000/(1.1)^5 = \$14{,}235{,}317}$$

$$\mathbf{NPV_A - NPV_B = \$5{,}765{,}000}$$

The net savings due to deferral is $5.8 million, or 29% of the cost of the transmission upgrade. The value of deferral depends on the time value of money, the rate of load growth, the capital costs of the transmission and generation alternatives, and the salvage value of the generation investment. The higher the time value of money and the slower the load growth, the greater the deferral value.

Fuel costs were ignored because the combustion turbine would be operating mostly during peak hours when the cost of power on the system is relatively high and presumably comparable to the production cost of the combustion turbine. The added benefit in Case B of extending the life of the transmission upgrade for 5 years was also ignored.

There are additional points that should be considered with respect to this type of application:

- The DG unit at L2 would probably not be able to economically export excess power back to the network. The example has assumed that the generator is supporting load growth at L2; hence, the bulk of the power must still come from the existing transmission line. The generator is not likely to have enough capacity to serve the entire load at L2, and if it did it would be during off peak hours when the value of power is low.
- A utility would need to have regulatory approval and incentive to accept a DG solution over a transmission upgrade. It is a riskier proposition for the utility because the DG unit is less reliable. Some utilities would be uneasy about relying on a single generator to serve customer loads, even if only during peak periods.
- If the DG unit trips while operating during peak hours the entire L2 load would probably be lost unless very fast acting load shedding devices were installed to support such an incident. The transmission line would not be able to pick up the loads because it presumably would not have the capacity.
- The fewer the hours that the DG unit is needed to serve the load, the fewer the probable customer outage hours. If the DG unit is needed 200 hours per year and its reliability is 95% then there will be 10 outage hours per year. If the DG unit is needed 2000 hours per year then the probable outage time is 100 hours per year. Load centers that have very sharp peak loads would be the most logical candidates for this type of application.

- The example assumes simple installation, fuel supply, electrical interconnection, permitting, and emissions issues associated with installing the DG unit. Complications will detract from the savings. Land is assumed available at negligible cost.
- The analysis assumes that the DG unit can be redeployed immediately to some other application within the system, and thus has a high salvage value. If the DG unit sits idle and the end of the transmission deferral the savings would be reduced accordingly.
- A DG unit placed at the substation, upstream of the control and protection equipment supporting the feeders, will have a simpler and less costly interconnection than a DG unit placed along feeder. A DG unit placed at the substation presumes that there is adequate downstream current carrying capability in the feeders. If the feeders do not have adequate capacity, or if the DG unit is placed on the feeder, additional costs will be incurred. These costs can be treated separately from the transmission deferral project, however, because they would be incurred with either the transmission upgrade or the deferral. DG/CHP can also be used to defer distribution investments, which will be discussed in a later section below.

Transmission Losses, Constraints and Locational Marginal Prices

The previous section showed the value of using DG to defer investments in a constrained transmission serving a load center. Transmission constraints can occur anywhere within a bulk power network and there is economic value in relieving those constraints. The value of relieving congestion and reducing losses is becoming increasingly apparent in deregulated markets that use locational marginal pricing. A locational marginal price (LMP) indicates the value of electricity at a specific time and location. LMPs have also been called time and area prices (TAP) in deregulated markets.

Utilities operating in regulated markets have not always taken into consideration the impacts of generation plant location on transmission costs and constraints. The two asset classes have often been treated independently, in sequence. New generation plants were located and then new transmission lines or upgrades were built to connect the generation plants. This approach was reasonable when few resources options were available and they were mostly large steam plants that had to be sited near limited sources of cooling water. Newer combined cycle plants have greater siting flexibility and can more easily take advantage of locations that support the transmission system. Utilities that practice integrated resource planning optimize transmission and generation investments (and other assets) together. Some resource planning computer models include transmission costs and losses along with generation production costs. These same computer models, with some modifications, are being used in deregulated markets to determine dispatch schedules and calculate LMPs. Deregulated markets make the economic costs of transmission constraints transparent though the use of LMPs. Some deregulated markets also incorporate transmission energy losses into LMPs. DG/CHP plants can use their size and siting flexibility to take advantage of the pricing discrepancies represented by LMPs.

Examination of a simple 3-node network as shown in Figure 6 can help explain the concept of locational marginal prices. Arrows pointing into a node represent generation; arrows out of a node represent loads. There is a power plant, G1, at Node A having a capacity of 100 MW and a marginal production cost of $75/MWH. A second power plant, G2, at Node B has a capacity of 200 MW and a marginal production cost of $50/MWH. G2 is the lowest cost resource in the network and is dispatched first. When G2 has available capacity and there are no transmission constraints or losses in the network, then the marginal cost anywhere in the network equals the marginal cost of G2, $50/MWH. The marginal cost of serving 75 MW of load (L1) at Node C is thus $50/MWH, as indicated in the Figure 6.

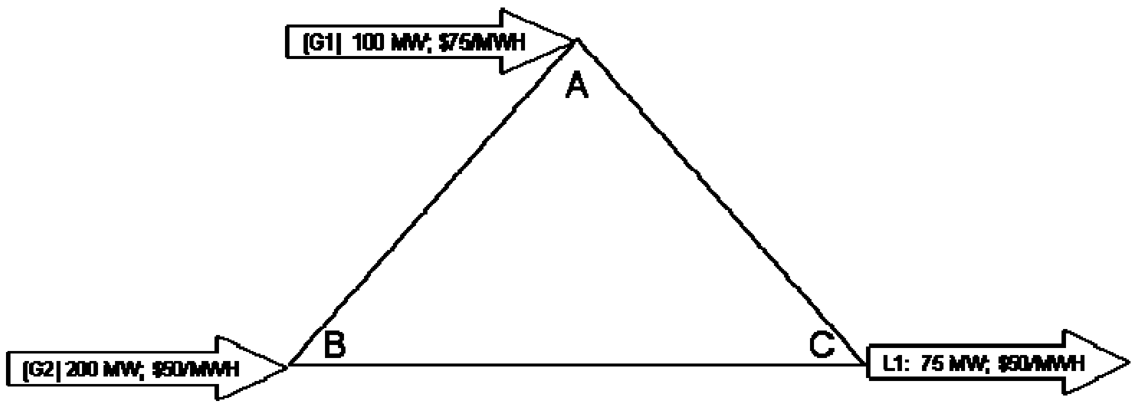

Figure 6 Marginal Price at Node C When G2 is the Marginal Unit (No Transmission Losses or Constraints)

After G2 reaches its capacity (200 MW) then G1 at node A is dispatched and the marginal cost everywhere becomes $75/MWH, as indicated for the load L1 at node C in Figure 7.

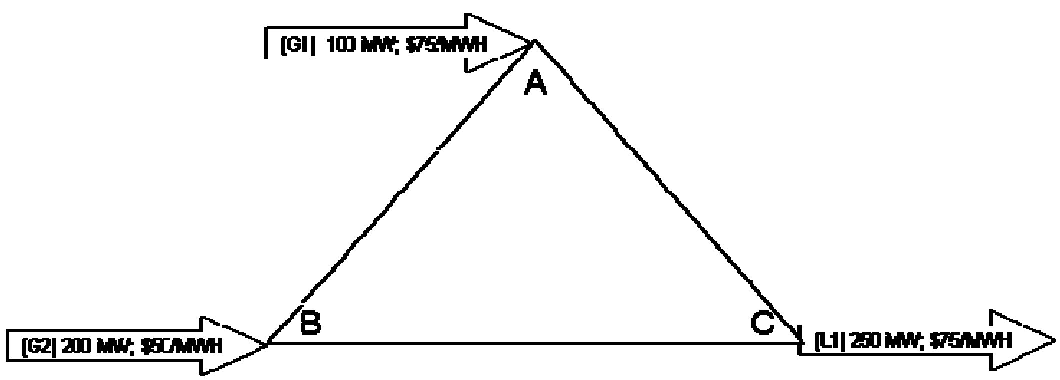

Figure 7 Marginal Price at C When G1 is the Marginal Unit (No Transmission Losses or Constraints)

Now consider the effects of a transmission constraint on line BC on the marginal cost at node C (Figure 8). To keep the analysis simple, assume the impedances of each segments, AB, BC and AC, are equal. The current flow from B to C can follow two paths, BC and BAC. Because the impedance of path BAC is twice the impedance of BC, the current and power flows along BC will be twice the flows along BAC. When 75 MW of power are flowing from B to C, 50 MW will be along BC and 25 MW along BAC. Once line BC reaches its 50 MW constraint, no additional power can flow from G2 at node B. Additional power will have to come from the higher cost G1 at node A. Power flow from G1 to C will be split between the paths AC and ABC, with the two-thirds of the power flow along AC and one-third along ABC, due to the 2:1 ratio of the impedances. With G2 at 75 MW and G1 at 1 MW, the transmission constraint would be exceeded. G2 would provide 50 MW via BC, and 25 MW via BAC, while G1 would provide 2/3 MW via AC and 1/3 MW via ABC. This net, superimposed segment flows would be 50 1/3 MW via BC, 24 2/3 MW via BA, and 25 2/3 MW via AC. The net flow to C would be 76 MW but the segment BC flow of 50 1/3 MW exceeds its limit. Therefore, to maintain the 50 MW limit on BC, the output of G1 would have to increase to 2 MW and G2 would have to be decreased to 74 MW. The marginal cost is therefore 2 x $75/MWH – 1 x $50/MWH = $100/MWH. This is quite interesting because the marginal cost at C is now greater than the marginal cost of either of the generators in the network. Every MW increase in load at C requires a 2 MW increase at A and a 1 MW decrease at B. In a real power system consisting of numerous generation plants, load centers and transmission connections, the LMP values can become very difficult to predict and volatile.

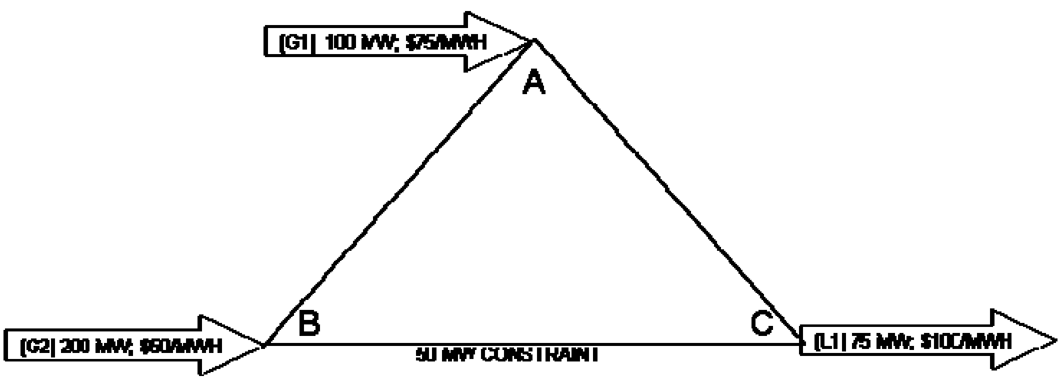

Figure 8: Marginal Prices With Transmission Constraints

Transmission line losses also affect locational marginal prices. If there is a 5% power loss from B to C the effective marginal cost at C when G2 is the marginal generator is 50 x 1.05 = $52.5/MWH. If the loss from A to C is also 5% the effective marginal cost at C when G1 is the marginal generator is 75 x 1.05 =$78.75/MWH. When the transmission line BC is constrained and the line losses are 5% then the marginal cost at C is $105/MWH. Line losses increase with the square of the current or power flows (at constant power factor), so losses during peak load conditions become increasingly significant. For example, if the average system line loss is 3% and the system peak load is twice the average load, then the loss during the system peak is 9%. When these losses become factored into LMPs there will be even greater incentive to place peaking resources near loads.

Developers of DG/CHP (or other) wholesale generation plants in deregulated markets wishing to take advantage of LMPs should become very familiar with the LMP patterns in the region where the plant will operate. LMPs are very volatile, with transmission constraints and prices varying by season and time of day. It is not yet clear if a developer would be able to take advantage of persistently high LMPs. In theory if you are a developer you could locate a plant near a constrained node, predict the marginal prices at the node for every hour of the year, and then bid just under those prices. During peak periods you would be bidding well over the marginal production cost of your plant. The rules of the market may not allow you to do this, however. Some markets do not allow widely varying cost bids from the same plant. In addition, if you do not share any of the savings with the system there will always be an incentive for a transmission solution or some other developer to enter the market at that node, and drive the price of your unit down to its marginal cost. Perhaps the ability to capture a premium price for a number of years before competitors can enter your market is enough incentive to develop your resource. Market managers and researchers are still debating how transmission lines or upgrades should be implemented. Should individual developers have the right to "own" an upgrade or a new line and collect "rent" based on the value of the asset, *e.g.*, the effect it has on lowering LMPs and line losses throughout the system? Or should the transmission assets be treated as a regulated monopoly, with new lines and upgrades receiving regulatory approval based on cost/benefit analysis and cost recovery via regulated tariffs? These types of issues are still being resolved.

The adoption of LMPs and the growth of retail electricity providers will result in greater segmentation of customers by cost of service. Customers in high cost regions will pay more as will customers that consume proportionately more electricity during peak times. This could create an opportunity for DG/CHP developers if they can offer retail providers lower cost solutions to serving their customers. DG/CHP solutions are more likely to be economic in high cost areas, but DG/CHP development costs can be higher in these areas as well, for instance in urban areas. On the other hand, there will be some regions that have high costs of service from the existing power system, but are favorable to the development of DG/CHP projects. Isolated communities that do not have sufficient local generation resources and receive most of their power from a long, fully loaded transmission line, for example, would be good candidates for DG/CHP projects. If regulated utilities have incentives to reduce operating costs in such areas they would also be interested in DG/CHP options.

DG/CHP within the Distribution System

In addition to the usual practice of using DG/CHP to lower individual consumers' electric bills DG/CHP can also be used to defer or avoid distribution system investments, in the same way as was discussed above with deferring transmission investments. The farther one goes out in the distribution system the greater the total capital investment to serve a customer load. Furthermore, the load factors (average load divided by peak load) tend to get smaller as well. A typical residential customer might have an average load of 1.5 kW and a peak load of 20 to 30 kW, a load factor of 5 to 7.5%. The utility makes a capital investment to serve a 30 kW load but on average is only serving a 1.5 kW load. When individual loads are integrated on feeders, and feeder loads integrated at substations the load factor improves, perhaps up to 10 to 40%; the capital equipment is still underutilized, however, and represents a major portion of the cost of serving customer loads. Furthermore, distribution system investments are "lumpy," they are only available in large increments and often have to be made well in advance of actual need. Hence, methods of deferring or avoiding these investments can significantly reduce the cost of serving customers.

As shown with the transmission investment example above, the ability to defer a distribution system capital investment has a value to the power system based on the time value of money. The value of the deferral equals difference in the net present value of the cash flows with and without the deferral. For example, suppose a utility distribution company determines that it needs add a new substation transformer upgrade to keep up with anticipated load growth. The current capacity of the substation is 10 MVA; the peak load is growing at 4.5% per year and will reach the capacity of the substation at the beginning of year zero. The new transformer upgrade will increase capacity by 10 MVA, costs $2,000,000 or $200/kVA and has an expected useful economic life of 30 years. As an alternative to the upgrade the utility is considering installing a reciprocating engine to defer the need for the transformer investment. The peak shaving reciprocating engine being considered has a capacity of 2 MVA and costs $500,000 or $250/kVA, total installed cost. The life of the engine is 20 years. The utility's time value of money is 9%.

The engine investment increases the capacity of the substation by 2 MVA and thus enables the transformer investment to be deferred until year four. The cash flows for the two cases are shown below in Table 12.

Year	Load (MVA)	CASE A: Transformer Upgrade		CASE B: Engine, Then Transformer	
		Capacity (MVA)	Investment	Capacity (MVA)	Investment
-1	9.6	10		10	
0	10.0	20	$2,000,000	12	$600,000
1	10.5	20		12	
2	10.9	20		12	
3	11.4	20		12	
4	11.9	20		20	$2,000,000
5	12.5	20		20	
6	13.0	20		20	
7	13.6	20		20	
8	14.2	20		20	
9	14.9	20		20	
10	15.5	20		20	
11	16.2	20		20	
12	17.0	20		20	
13	17.7	20		20	
14	18.5	20		20	
15	19.4	30	$2,000,000	30	$2,000,000
16	20.2	30		30	
17	21.1	30		30	

18	22.1	30		30	
Load Growth Rate = 4.5%/yr					

Table 12 Using an Engine to Defer a Transformer Investment

A simple way of performing this evaluation is to convert the investment costs into equivalent level annual payments. For both cases it can be assumed that the transformer is replaced every 30 years at the end of its life so that the equal annual transformer payments go on to infinity. In Case A (Transformer Upgrade) the transformer is purchased at the beginning of year 0, and in Case B (Engine Deferral) the transformer is purchased at the beginning of year 4, when the engine no longer has enough capacity to defer the purchase of the transformer any longer. The equal annual transformer payments extend to infinity in both cases, so only the annual payments in years zero to three matter. Also, note in the table that in year 15 (assuming constant load growth) another transformer investment would be required in both cases to satisfy additional load growth. Because the investment is the same in either case it is ignored. The value of the deferral is the difference in NPV for the cash flows in years 0 to 3 for the two cases.

The level annual payment is $179,599 for a $2,000,000 transformer upgrade having a 30 year life and using a 9% discount rate. The annual payment is $50,251 for a $500,000 engine having a 20 year life. Payments are assumed to occur at the beginning of the year.

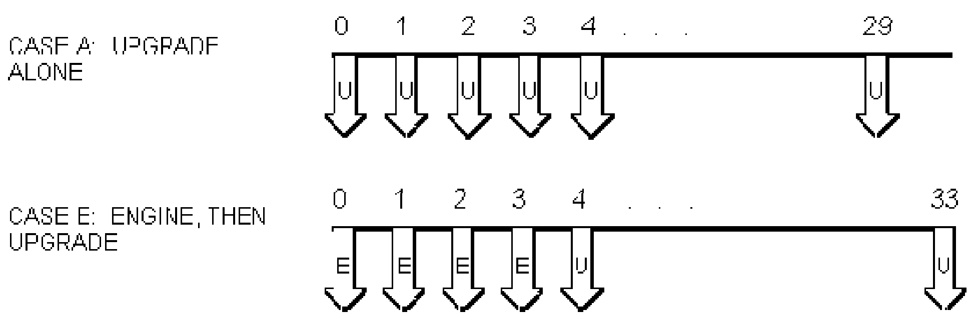

Figure 9: Cash Flow Model for Substation Upgrade Investment Deferral.

Figure 9 shows the cash flows for the two cases. U is the level annual payment for the transformer upgrade investment; E is the level annual payment for the engine investment. The net present values of the cash flows for years zero through three are:

PV_A=U + U/(1+i) + U/(1+i)^2 + U/(1+i)^3
PV_B=E + E/(1+i) + E/(1+i)^2 E/(1.i)^3
PV_A-PV_B=(U-E) [1+1/(1+i) + 1/(1+i)^2 + 1/(1+i)^3]

For U=$178,599, E=$50,251, and i=9%,
PV_A-PV_B=$453,000

This represents a capital investment savings of 23% of the cost of the upgrade, a significant amount.

There are some caveats and assumptions that are important to note in this analysis:

- The amount of deferral benefit is a function of the cost of capital, the cost per kW of the engine, the cost per kW of the upgrade, and rate of growth of the load. The slower the growth rate, the greater the potential for deferral. The cost per kW of the transformer is based on the capacity of the transformer not on kW of load served by the transformer. The savings are due to the fact that transformer upgrade projects come in fixed, lumpy sizes so you often have to buy a lot more capacity than you need. The example assumes that you have more sizing flexibility with the engine; you can buy just the capacity you need. In fact, if you take this example to an extreme you can put a different engine in each year, just slightly above the peak load forecast. This approach might minimize investment cost, but you would have to trade off that benefit against the implementation costs of shuffling engines in and out service.
- The example assumes installation, permitting, emission control, siting, fuel supply, land availability and noise control are not difficult or costly.
- The analysis ignores the cost of the fuel consumed by and the value of electricity produced by the engine. Since the engine would be operating during peak periods the cost of electricity produced by the engine will be less than or comparable to the cost of "buying" power from the system.
- The example assumes that the engine can be redeployed immediately in some other application within the system. If the engine sits idle the savings would have to be reduced accordingly.
- An engine does not provide equivalent reliability to a transformer upgrade. Many utilities would be uneasy about relying on a single engine to serve customer loads. If the engine operates 200 hours per year and its reliability is 95%, then the outage time is 10 hours per year, which is higher than utility standards but perhaps acceptable for some distribution feeders. Careful preventive maintenance, condition monitoring and testing could perhaps bring the reliability up to 99%, which would correspond to two hours of outage per year. The sharper the peak load being served by the engine the fewer the expected outage hours. Some distribution circuits have very sharp "needle peaks" and would perhaps only require 100 hours per year of engine operation.
- After load grows enough to justify the investment the transformer can then be installed and the engine redeployed to another site.
- CHP projects are generally not the best choice for distribution investment deferral. CHP plants usually operate base loaded whereas a peak shaving unit is all that is required. A CHP plant could potentially get credit for deferral if it can reliably shave peak loads. Multiple, smaller DG/CHP units, scattered throughout the capacity constrained region, and all committed to operate during local peak periods, would probably provide the utility with greater confidence than a single unit.
- If the DG unit is placed at a substation, upstream of the control and protection equipment serving the feeders, the interconnection of the DG unit will be relatively simple and inexpensive. A DG unit placed at the substation presumes that there is adequate downstream current carrying capability in the feeders. If the feeders do not have adequate capacity, or if the DG unit is placed on the feeder,

interconnection costs are likely to be higher. If distribution feeders are fully loaded, on the other hand, DG units can be placed to defer feeder upgrades. Feeder upgrade costs on average are lower than transformer upgrade costs, but there is wide variation in both costs.

- Deferral buys you time until the uncertainty of load growth is resolved. Small investments such as an engine can be used until enough load materializes to justify the big investment.
- Existing backup generators are a potential low cost resource for deferring distribution investments. Many customers that need higher reliability than standard utility service already have backup generators. Utilities could make arrangements to dispatch these units during peak periods by providing incentives to the customer. One incentive would be to take responsibility for maintenance and periodic testing of the unit; however, this does create some liability issues if the unit fails during an emergency. The units could either shave the load of the customer, or export power back to the feeder. For the export option the units would have to be capable of paralleling with the grid continuously, not just during the transition from grid to generator as is common with backup generators. Codes regarding use of emergency backup generators as backup units would have to be addressed also.
- Many studies have identified the potential for DG to defer lumpy distribution investments; studies on the potential for utilities to use smaller lumps of distribution equipment either do not exist or are not widely known. Transformers can be made in any size, and could be rotated in and out of substations just as engines can. The savings potential from using small conventional distribution upgrades would presumably be just as large as from using DG.

Using Distribution System Marginal Costs to Stimulate DG/CHP Development at the Right Times and Locations

Another way of deferring (or avoiding) distribution system investments is to rely on numerous small resources. The theory of using locational marginal prices (LMPs) or time and area costs (TACs) to represent actual economic costs is also applicable to the distribution system. Markets for LMPs do not exist in distribution systems as they do in transmission systems; distribution systems are regulated at the state level and not subject to FERC market rules. Nevertheless state regulators are interested in least cost methods of serving loads and recognize that detailed knowledge of investment costs as revealed by LMPs present an opportunity for alternatives to compete against traditional "wires" solutions. California's Public Utility Commission (CPUC) is considering adoption of an avoided cost methodology based on time and area costs to determine the value of energy efficiency and demand response programs [7][i]. The TACs are calculated by first levelizing to annual charges all of the planned distribution investments in a given area, and then allocating the annual charges to peak periods during the year. Figure 10 shows an example of how costs were allocated for one particular region as a function of time of day and month.

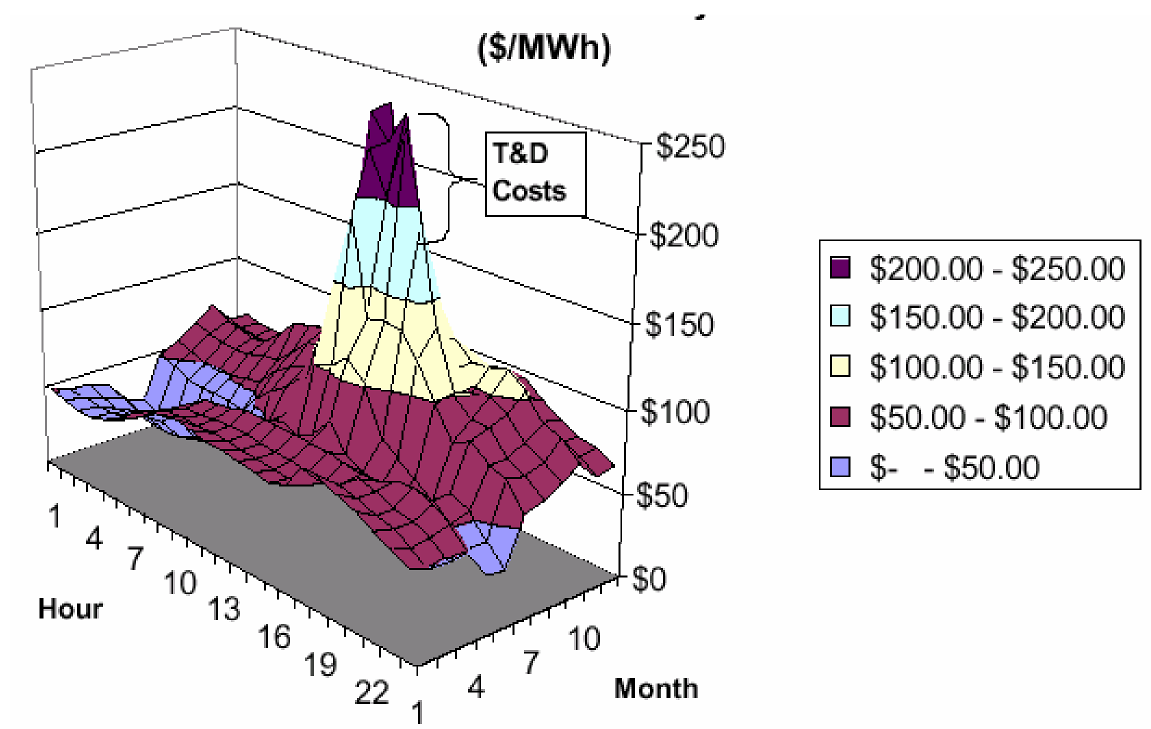

Figure 10 Marginal Prices at a Specific Location in the Distribution System. {Figure 2 from Ref 7[iii] }

The figure includes many components of marginal costs: transmission and distribution (T&D) investments, generation capacity investment, generation energy value, avoided emissions, and system fuel gas purchases. (Presumably in a fully deregulated market only the avoided distribution costs would still be under the jurisdiction of state regulators.) The transmission and distribution costs are the top two segments. The T&D investments were allocated in proportion to ambient temperatures because of the strong correlation between temperature and peak loads. The peak prices occur during the hottest hours of the summer months.

This data is proposed to be used to determine the value of energy and capacity reductions due to energy efficiency and demand response (EE/DR) programs. Those programs that reduce loads at the right places and times are worth the most. The data can also used in time of use electric rates to provide accurate economic signals to customers to reduce their peak loads. In this way both utility sponsored EE/DR programs and customer initiated conservation efforts will see price signals that reflect the true economic cost of adding transmission and distribution capacity. DG/CHP resources may also be treated in the same way, if not explicitly allowed by regulators, implicitly by way of customers who choose to subscribe to real time energy prices.

There are some issues with respect to using LMPs with DG/CHP/EE/DR resources:

- The LMPs have to be very location specific. If a specific distribution circuit is overloaded the LMPs would have to be tied to that circuit. The distribution system investment costs used to calculate LMPs cannot be averaged across a broad area; otherwise the supply or demand side resources that are developed in response to the LMPs might not be developed in the right locations. LMPs are mostly applicable for small resources on the customer side of the meter, such as energy efficiency, demand response and small DG/CHP that are of similar size as the loads. Large resources would have to be analyzed individually, as when specific resources were compared against distribution investment upgrades in the section above.

- The marginal resources being relied upon must be collectively as reliable as conventional distribution system investments or as statistically predictable as customer loads. Numerous small unit resources are inherently more reliable than a single unit, even when the small units are not necessarily under the utility's control. Reliance on many units avoids the problem of the failure of a single unit bringing an entire distribution circuit or substation down. Small units would not need to be dispatched by the utility; they would have dispersed and random effects on the local system similar to individual loads. Units would be self dispatched based on the price signals. It would be in the economic self interest of the owners of the units to make sure they operate during the right times. The operating patterns of units during critical peak periods would become known over time.
- Timing and planning are critical. If the utility knows that 10 MW of capacity will be needed in 2 years, it would be uneasy about assuming that 10 MW of DG/CHP/EE/DR resources will automatically develop as needed. The resources will not develop until after the prices have been in effect for some time. Prices may have to be "spiked" in advance of actual capacity shortage to get a head start on resource development. A contingency approach would be for the utility to have DG resources available to fill in any gaps left by customer sited resources. Over time market responses to price signals will become more predictable.
- DG/CHP/EE/DR developers would need to understand that LMPs can be volatile. Prices will go up and down depending on whether capacity is abundant or in short supply. This can make investment planning complex for resource developers, which in turn will make the utility less confident that the resources will be developed when needed. Regulators, utilities and resource developers all may prefer the certainty of contracts that provide assured prices over reasonable time periods than dealing with more variable LMPs, especially for larger resources.

Conclusions

This report evaluated opportunities for the deployment of distributed generation / combined heat and power generation resources in wholesale power markets. The value of the power produced by these resources in a hypothetical power system was analyzed using both traditional utility resource planning and deregulated market analysis methods. While in theory the opportunities for DG/CHP in regulated and deregulated markets are similar due to the fundamental cost structure of the industry, there are subtle differences in how the value of electricity is determined and the ability to exploit the opportunities. Deregulated markets are unbundling costs, making prices transparent, and generally lowering barriers to entry for non-traditional resources. Regulated markets can create the same opportunities, but only if they are recognized and supported by regulatory action; the extent to which DG/CHP can participate in wholesale markets varies by jurisdiction, but in general is increasing over time. The application opportunities for DG/CHP evaluated in this report include bulk power generation, reduction of power system operating costs, relief of transmission constraints, and deferral or avoidance of transmission and distribution systems investments.

Bulk power generation is a base-loaded application that requires low production costs. CHP projects that utilize most of the waste heat that they generate can have very low production costs and be competitive with traditional, large base-load utility resources. Examples in this report showed how these resources would be dispatched according to production costs and the value of the electricity they could generate in both regulated and unregulated wholesale markets. the capital costs of new base-loaded resources is relatively high and usually cannot be justified based on operating cost savings over existing resources alone; new resources are economically viable usually only when power system load growth or plant retirements occur. This report did show examples, however, in which large, low-cost CHP plants could compete against typical old generation resources that might be found in power systems in the U.S. today.

The report provided other examples for intermediate- and peaking-duty DG resources. On/off cycling of intermediate-duty DG resources can reduce operating costs in systems using old, inefficient steam plants for load following and system support. Finally, in peak-shaving applications, DG resources can take advantage of their smaller size and siting flexibility to relieve transmission constraints and/or defer investments in transmission and distribution assets. The value of relieving transmission constraints is becoming increasingly apparent in the high locational marginal electricity prices that exist in some deregulated markets. The economic value of using DG to defer transmission and distribution investments until load grows enough to justify them was demonstrated. The value of using a DG resource to defer a distribution investment for four years was equal to nearly a quarter of the capital cost of that distribution investment.

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