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Utility Distributed Generation Applications in the Cape Light Compact Communities

Prepared for:

Cape Light Compact
Barnstable, MA

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EXECUTIVE SUMMARY

Objectives

The goal of this project is to estimate the amount of distributed generation (DG) that may be cost-effective for the Cape Cod peninsula and Martha's Vineyard, comprising the Cape Light Compact Communities. The analysis examines a "utility level" application of distributed generation as an economic alternative or augmentation to investment in transmission and distribution facilities. This type of analysis is very different from DG analyses that examine "end user" applications for DG, and which were performed in a companion study. Estimates are made for three years: 2005, 2010 and 2015. Six existing and emerging DG technologies were considered in the evaluation.

The results are intended to provide decision-makers for the Cape Light Compact Communities ("the Compact") with a broadened context for considering the near term and long term potential for cost effective and clean "utility level" distributed generation in the area. It also provides a basis for consideration of regulations, policies, practices and planning that enable prudent use of cost-effective and "clean" (i.e., low-emission) DG resources as an alternative or augmentation to transmission and distribution system investment.

Methodology

Six state-of-the-art, dispatchable, emerging distributed generation technologies were evaluated. These include: microturbines, natural gas fired engines, propane fired engines, phosphoric-acid fuel cells, proton exchange membrane (PEM) fuel cells, and advanced fuel cells. Distributed energy storage and geographically targeted demand-side management (DSM) and energy efficiency (EE) programs were not addressed by this study.

To perform the evaluation, DUA compared the costs to own and operate DG technologies with the benefits to be derived from their operation in specified applications. The cost-effectiveness of DG is then expressed as a benefit-to-cost (B/C) ratio: if the ratio is greater than 1.0, then DG is cost-effective; if the ratio is less than 1.0, it is not.

Evaluations are performed for applications in which the DG is operating in peaking and baseload modes. For each of these cases, the distributed generation is assumed to be sited at either substation or feeder locations (i.e., at or near loads – see Figure 2 in Section 3), thereby capturing the benefits of avoided transmission and distribution costs. NSTAR provided the estimates for projected capital expenditures for T&D, which were used as the basis for avoided T&D costs.

The analysis also considered the effect on B/C ratios for DG if national average T&D costs were used instead of the NSTAR data, allowing the Compact to consider how the cost-effectiveness of DG may be impacted by more typical T&D infrastructure costs. Although NSTAR's currently anticipated T&D expenditures are significantly below the national average, NSTAR's historical expenditures over the last five years are consistent with the national average.

Because the avoided costs exhibited little or no variability in magnitude, a statistically based approach to evaluating DG economic potential was not considered necessary for this analysis.

The maximum potential size of the market for distributed generation is defined as the "load in play." For this study, the load in play is equal to the load growth, comprising new load that could be served with DG.

Results

The cost-effectiveness of DG is expressed as a benefit/cost (B/C) ratio; a result greater than 1.0 indicates the DG is cost-effective. Benefits ascribed to the DG will include avoided energy costs, capacity deferral (generation, transmission and distribution), loss reduction, reliability enhancement, and others as applicable to a given utility situation. The total costs to own and operate DG includes purchase and installation costs, fuel expenses, financing, and operating and maintenance (O&M) costs. The B/C ratio is simply the benefits divided by the costs.

As described below, the analysis utilizes NSTAR's presently anticipated T&D costs for the Cape and Vineyard, as well as a comparison of these costs to national averages for T&D costs. Given NSTAR's presently anticipated low level of T&D costs, the potential for utility application for DG may seem limited. Nevertheless, considering the fact that DG is cost-effective for areas with more typical T&D costs, and that NSTAR's historical costs for the Cape and Vineyard are consistent with those typical costs, DG remains a potentially important strategic option for the Cape and Vineyard.

Specifically, DG provides an important alternative when planning for future electric supply needs and when responding to possible T&D system-related challenges, such as an unexpected need for expensive transmission and distribution upgrades, and difficulties associated with an underwater cable serving Martha's Vineyard. In the latter case, modern low-emission DGs may be the only option, at least for temporary service.

Evaluation Using NSTAR's Current T&D Cost Estimates

For the analysis, 4.3 $/kW-yr for distribution capacity and 1.6 $/kW-yr for transmission capacity were used (a total of $5.9 $/kW-yr). These figures were derived from NSTAR data for currently anticipated T&D capital expenditures [Ref. 1]. Other benefits included avoided energy costs of 19.8 $/kW-yr, and service reliability improvement of 6.5 $/kW-yr. (For a detailed description of assumptions, and the resultant benefits as functions of substation/feeder location and year, please see Section 2).

Figures ES-1 and ES-2 show the B/C ratios for peaking applications at substation and feeder locations, respectively, for all six technologies, for the three study years. These graphs show that there are no DGs for peaking applications with a benefit/cost (B/C) ratio exceeding 1.0 for any of the years evaluated. For 2005 the natural gas engine is the most cost-effective option, with a B/C ratio of about 0.43 (at substations) or 0.46 (at feeder locations); in 2010 these ratios increase to 0.53 and 0.56, respectively. In 2015 the most cost-effective option is the advanced fuel cell with a B/C of about 0.72 at substations and 0.76 at feeder locations. The low transmission and distribution costs are the primary reason for such poor economics.

Figures ES-3 and ES-4 show the B/C ratios for baseload applications at substation and feeder locations, respectively, for all six technologies, for the three study years. There are two cases for

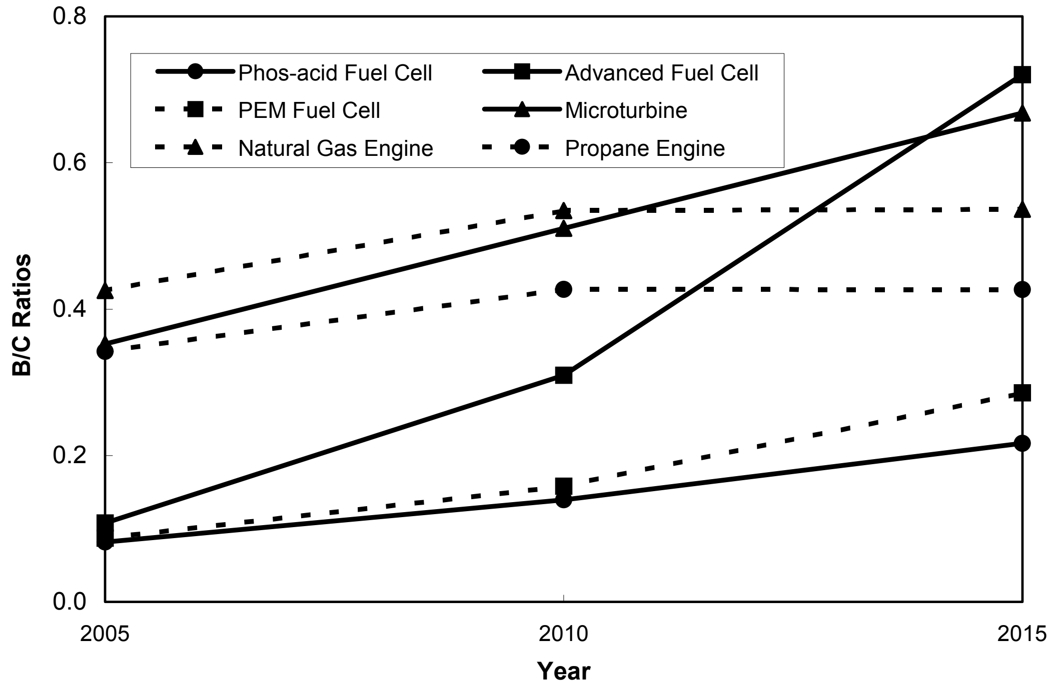

Figure ES-1. Benefit/Cost Ratios for Distributed Generation, Peak Load, @ Substations, for Current NSTAR T&D Avoided Cost Estimates

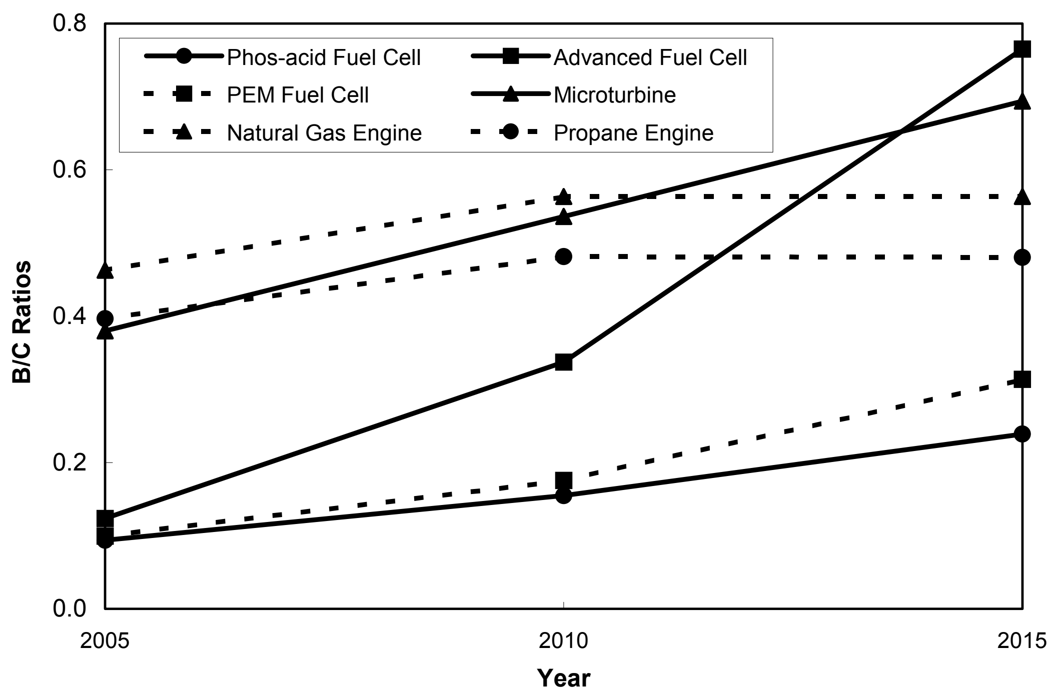

Figure ES-2. Benefit/Cost Ratios for Distributed Generation, Peak Load, @ Feeders, for Current NSTAR T&D Avoided Cost Estimates

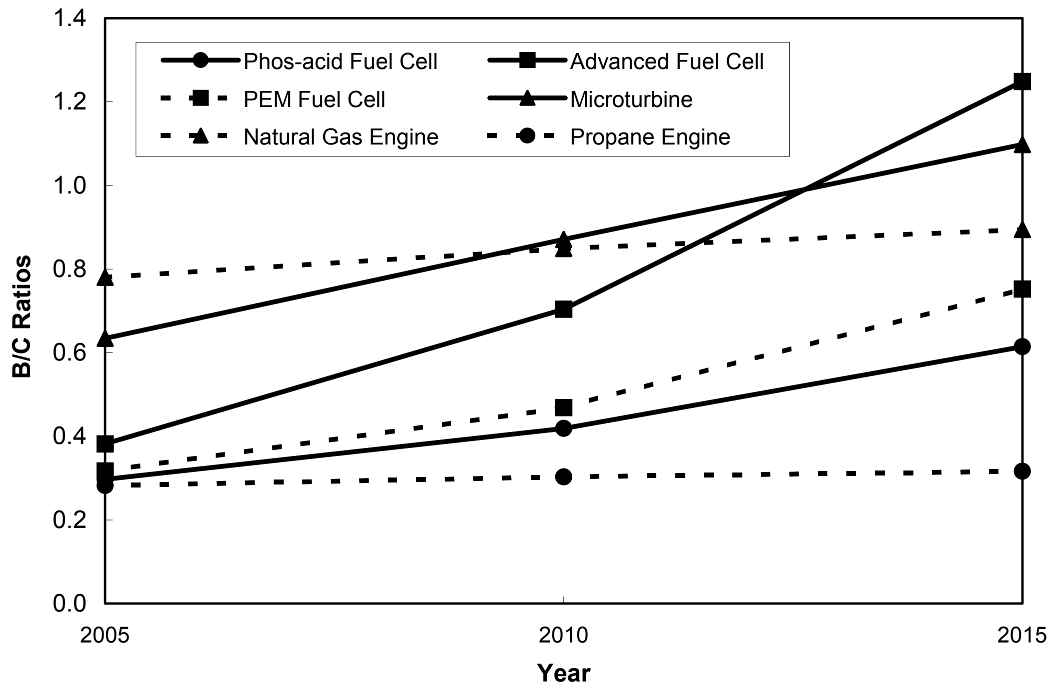

Figure ES-3. Benefit/Cost Ratios for Distributed Generation, Baseload, @ Substations, for Current NSTAR T&D Avoided Cost Estimates

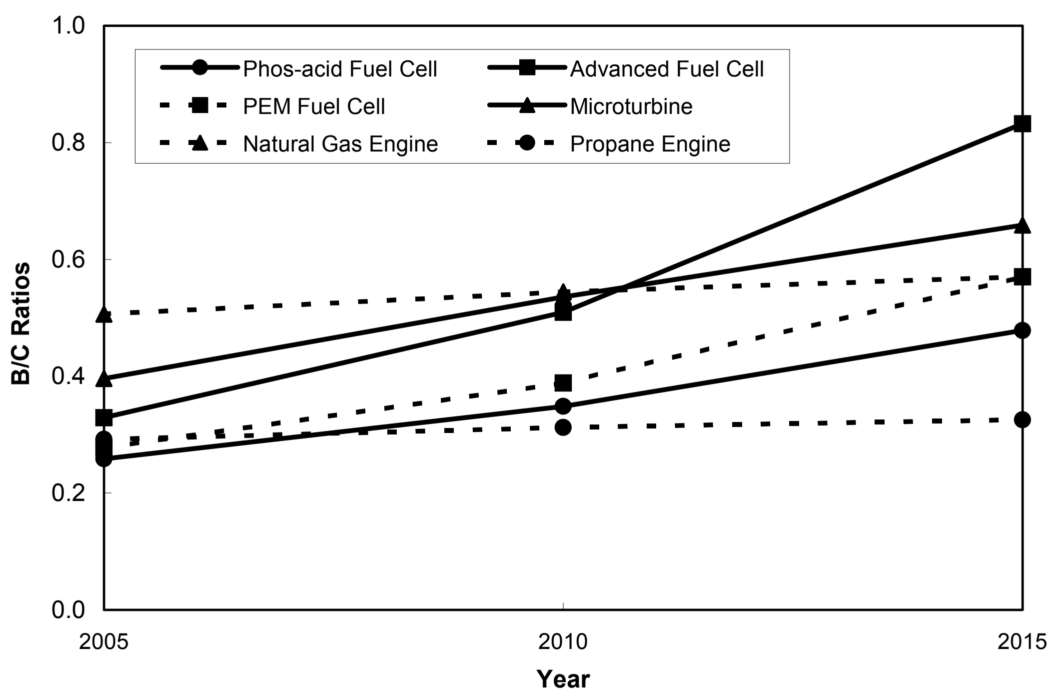

Figure ES-4. Benefit/Cost Ratios for Distributed Generation, Baseload, @ Feeders, for Current NSTAR T&D Avoided Cost Estimates

which DGs have a B/C ratio exceeding 1.0. Both occur in 2015 and both occur at the substation locations: the advanced fuel cell has a B/C of about 1.25 and the microturbine has a B/C ratio of about 1.1 (Figure ES-3).

B/C ratios for baseload DGs at feeder locations were substantially below 1.0 in all years, for all DGs. This is primarily because the natural gas fuel price assumed for feeder locations (retail) is much higher than the price assumed at substation locations (city gate). Baseload DG economics are very dependent on the ability to produce low-cost energy, as opposed to peaking applications, which are mainly dependent on the ability to provide capacity.

Therefore, DGs will have a difficult time competing with the grid for baseload/energy applications, given NSTAR's currently anticipated avoided costs for the region. If DG technology cost and performance parameters improve, or if T&D costs increase, this situation will change.

Evaluation Using National Average Avoided T&D Costs

When assuming national average T&D cost values – 30 $/kW-yr for distribution and 12.1 $/kW-yr for transmission – the prospects for both peaking and baseload DGs improve. Figure ES-5 shows B/C results for peaking DG at feeder locations and Figure ES-6 shows B/C results for baseload DG at substation locations, using these national average T&D costs instead of the previous values derived from NSTAR data.

Comparing Figure ES-5 to Figure ES-2, it can be seen that in 2005 B/C ratios would improve from a range of about 0.1 to 0.4 to a range of about 0.2 to 0.7. In 2010, B/C ratios for several technologies are close to 0.8, whereas previously they were in the 0.5 – 0.6 range. By 2015 the microturbine and advanced fuel cell are easily cost-effective, whereas previously their B/C ratios were below 0.8.

Comparing Figure ES-6 to Figure ES-3, it is apparent that the effect on B/C ratios in 2005 is very small, but in 2010 the natural gas engine and the microturbine are very close to being cost-effective. In 2015 the advanced fuel cell and the microturbine are very cost-effective.

Despite relatively low T&D upgrade costs anticipated by NSTAR in the immediate future, it is still important to evaluate DG as an option for the longer term, when capacity may become tighter and T&D infrastructure will become more expensive, meeting or even exceeding historical national averages. It is also important, as noted above, to evaluate DG as an alternative for meeting particular T&D system challenges on certain circuits on the Cape, or for T&D challenges for communities on Martha's Vineyard.

Emissions Impacts

In most cases DGs would reduce the overall air emissions of CO_2 and NO_X, relative to the amounts that would otherwise be produced from energy from NEPOOL. The primary reason for this is the fact that new generation in New England must meet NO_X emission limits of 1.5 lb/MWh, and in many cases they are not only much lower than this, but also lower than the NEPOOL average.

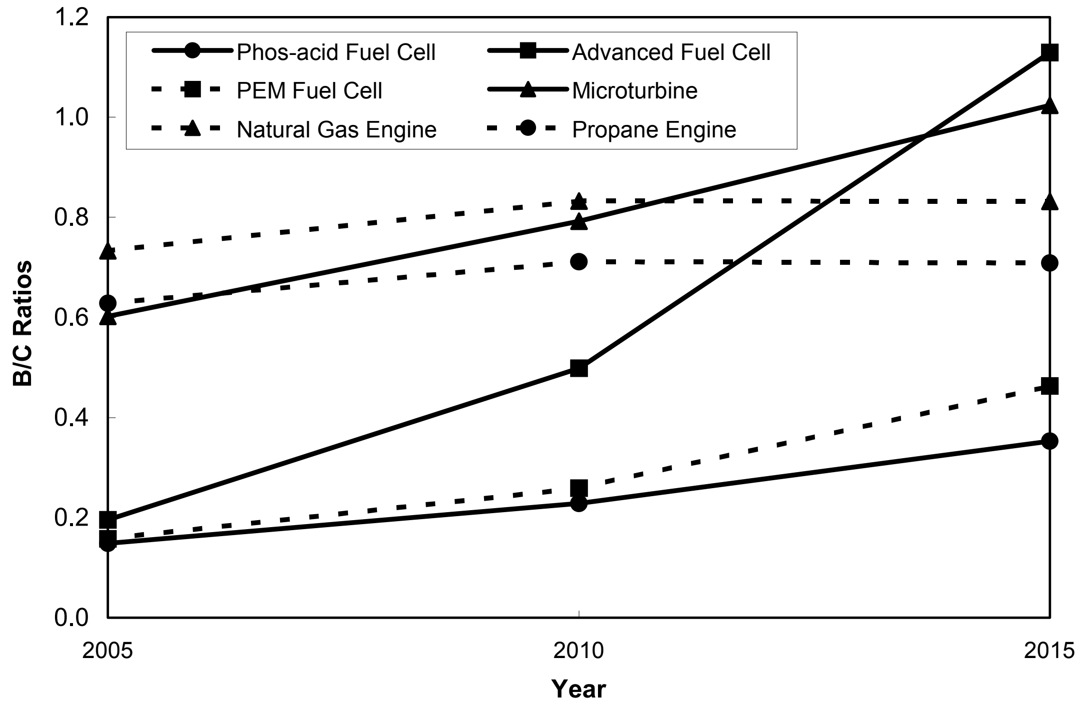

Figure ES-5. Benefit/Cost Ratios for Distributed Generation, Peak Load, @ Feeders, for National Average T&D Avoided Cost Estimates

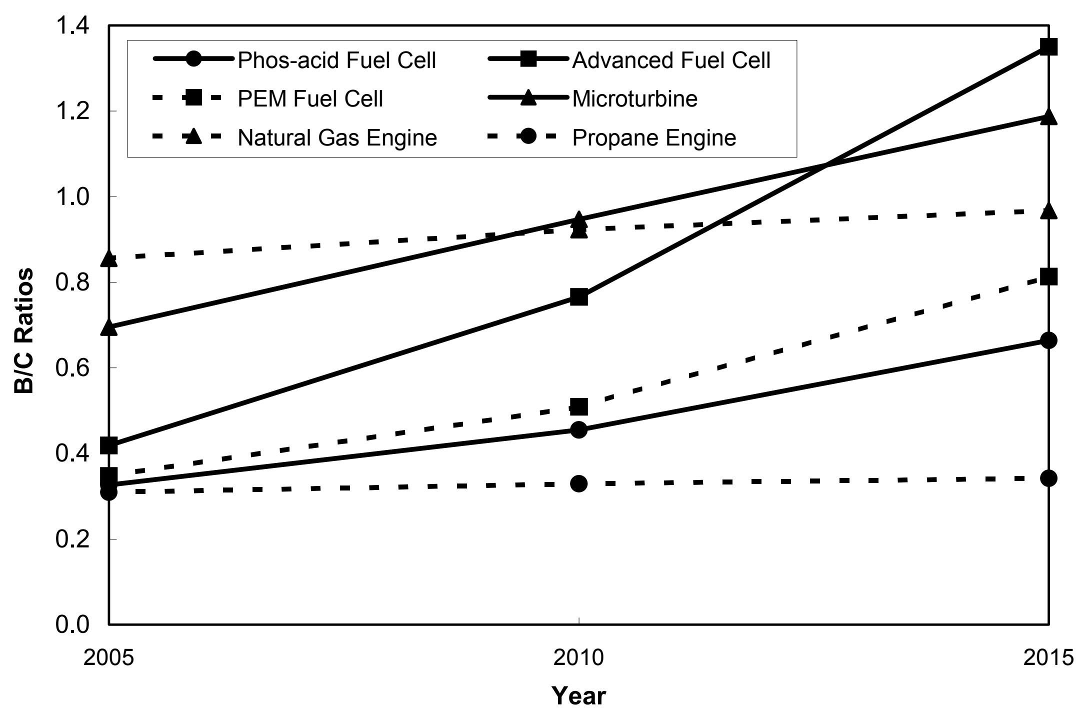

Figure ES-6. Benefit/Cost Ratios for Distributed Generation, Baseload, @ Substations, for National Average T&D Avoided Cost Estimates

Conclusions

Distributed generation is an emerging option for utilities. However, based on currently anticipated T&D upgrade costs provided by NSTAR for this study, as of this writing DG does not appear to be a cost-effective utility alternative. However, should conditions change, DG may indeed be a cost-effective option in some situations; specifically, if:

a) regional electricity supply prices increase significantly,
b) transmission congestion charges become a significant cost factor,
c) transmission or distribution upgrade costs are higher than costs presently assumed for this study (i.e., are similar to the national average or to NSTAR's historical costs),
d) localized service reliability decreases, or
e) a fixed charge rate lower than 0.15 can be used for DG (e.g., due to depreciation rules equivalent to those for transmission and distribution, and/or better familiarity with DG investments)

Recommendations

The DG option should be included in the planning process for transmission and distribution expansion. In particular, a process in which transmission and distribution loading conditions and cost estimates for likely system upgrades are evaluated systematically, identifying system "hot spots," would allow identification of high-value situations for which DG may be cost-effective.

Other distributed resource options, including distributed energy storage and geographically targeted energy efficiency and demand side management measures, could be considered as potential cost-effective alternatives to utility infrastructure projects. If these technologies are installed downstream from an overloaded or nearly overloaded distribution node, the benefits can be of the same magnitude as those associated with electric supply (e.g., reduced generation capacity needs and fuel use, T&D losses and air emissions).

Emerging energy storage technology (primarily batteries) may be an important cost-effective alternative to DG, especially if environmental impacts are a key consideration.

Renting or leasing DG or DS equipment may be a viable option. By renting, financial and operating risks are minimized and flexibility is maximized. If the DG is needed for only a few months per year (e.g., for June through September to serve the summer peak), then the annual cost may be lower than if the DG is owned. In fact, because a small amount of distributed resources (of any type) can defer transmission and/or distribution upgrades that are relatively large, such single-year deployments of distributed resources may be quite cost-effective.

Unique issues shape prospects for DG on Martha's Vineyard. Martha's Vineyard is supplied by an underwater transmission cable and is served by a radial supply system with no alternate supply lines. In this study, Martha's Vineyard was treated in same manner as the Cape; however, additional analysis would be possible if refined information concerning Martha's Vineyard is available. No natural gas is available on Martha's Vineyard; however, liquefied natural gas (LNG) could be investigated as an option, especially for peaking applications that don't require large amounts of fuel storage.

Section 1. Introduction

Study Scope, Goal and Objectives

The goal of this project is to estimate the amount of distributed generation (DG) that may be cost-effective for the Cape Cod peninsula and Martha's Vineyard, comprising the Cape Light Compact Communities (the area). Estimates are made for three years: 2005, 2010 and 2015. Six existing and emerging DG technologies were considered in the evaluation.

The evaluation reflects the T&D system perspective: it is based on utility financial criteria and avoided cost, i.e., cost that can be avoided if DG is used in lieu of the conventional grid alternative.

The results are intended to provide decision-makers for the Cape Light Compact Communities ("the Compact") with a broadened context for considering the near term and long term potential for cost effective and clean distributed generation in the region. It also provides a basis for the consideration of regulations, policies, practices and planning that enable prudent use of cost-effective and clean DG resources.

At present, given the expected costs of T&D service in the region, the potential for distributed generation may seem limited. Nonetheless, considering the fact that DGs *are* cost-effective for areas with more typical T&D costs, DG seems to be a potentially important strategic option.

Specifically, DG provides an important alternative when planning for future electric supply needs and when responding to possible T&D system-related challenges, such as an unexpected need for expensive transmission and distribution upgrades, and difficulties associated with an underwater cable serving Martha's Vineyard. In the latter case modern, low emission DGs may be the only option, at least for temporary service.

The Distributed Utility Concept Overview

The Distributed Utility (DU) concept involves use of modular distributed electric energy resources (DRs) including generation, storage or geographically targeted demand side management or conservation. DRs are sited at or near locations where electricity is used. DRs <u>complement</u> the greater electric grid by serving localized capacity or energy needs in lieu of additional "central" utility system/grid capacity (generation plus transmission plus distribution).

Cost-effective DRs provide capacity needed to supply electric energy when and where needed, within an electric utility's distribution system or at energy end-users' facilities. Usually the amount of DR capacity added is the amount needed to meet load growth as it occurs.

In contrast, conventional grid capacity must be added in relatively large "lumps." That is, by nature T&D upgrades usually involve addition of (load carrying) capacity that far exceeds load served during the first few years of service. Capacity upgrades of 33% are not uncommon (e.g., a substation rated at 15 MVA is upgraded to 20 MVA, a 5 MVA upgrade.)

Two considerations are worth noting. First, a large portion of the capacity increase from conventional transmission and distribution additions is not used during the first several years of the equipment's life. In the example above, if the load growth rate is 2%, then in the first year after an upgrade the load growth is 0.02 * 15 MVA = 300 kVA, whereas capacity added to the system is 5 MVA. The effect is a very underutilized T&D asset for several years. In addition to the direct financial implications, there may be significant financial risk associated with lump investments if there is a chance that some or much of the capacity may never be used

DRs used to defer T&D upgrades may also provide additional benefits that conventional utility T&D infrastructure upgrades cannot, such as those associated with electricity production on-peak and improved localized power quality.

Even if not needed for a specific utility system application, DRs could be used by electric service providers to deliver "value-added" services such as high reliability or premium power programs, within specific areas of a service area or to specific customers.

New players in the deregulated electric utility industry, such as electric service providers (ESPs), may employ individual or aggregated distributed resources as competitive offerings to customers and/or the greater electricity marketplace.

Electric utility customers may install distributed resources to reduce overall energy costs ("bill management"), or to provide elements of electric service not available from the utility, such as high electric service reliability, high quality power or heat for industrial processes.

Given these benefits and emerging trends in the electricity marketplace, there are strong indications that interest in DGs by utilities, their competitors (e.g., energy services providers and other utilities), and their customers is growing. Interest in DG is driven by the need to reduce cost or to provide benefits that the standard utility solution – upgrades to the grid infrastructure – cannot.

Distributed Generation Technologies

For this study, six state-of-the-art and emerging distributed generation technologies were evaluated. These include: microturbines, natural gas fired engines, propane fired engines, phosphoric-acid fuel cells, proton exchange membrane (PEM) fuel cells, and advanced fuel cells.

Distributed energy storage and geographically targeted demand-side management (DSM) and energy efficiency (EE) programs were not addressed by this study.

Section 2. Assumptions

Supply and T&D System Assumptions and Avoided Cost

This section covers the assumptions used for this study to reflect grid-related costs associated with electric service in the Compact's region. These assumptions include, for example: 1) peak load and peak load growth, 2) prevailing wholesale energy prices, 3) generation capacity value, and 4) transmission and distribution upgrade costs.

System Load, Load Growth, and Load In-Play

Readers should note that, for this study, it is assumed that existing utility equipment would not be replaced with DG: It is unlikely that existing utility distribution or transmission capacity with a useful life will be removed or decommissioned so that DG can be used. Therefore, DG would be used only to serve load growth in the distribution system. The implication is that the "market potential" for DG is based on the load growth, not total load. The maximum market potential for the evaluation is referred to as "load in play": the amount of load for which it would feasible to consider using DG to serve.

Shown in Table 1 are the expected system loads for the years 2005, 2010 and 2015. Also shown are load growth rates during and load growth within the years 2005, 2010 and 2015. Based on the peak loads and on the load growth rates, for this study average coincident peak load growth is estimated to be 14.4 MW in 2005, 10.6 MW in 2010, and 11.7 MW in 2015.

To translate peak load growth figures to load in play, a factor of 1.6 is applied. This reflects the fact that distributed generation will be serving non-coincident loads in the distribution system, rather than coincident loads as seen by the central supply system. It also is based on the fact that many distribution systems have unused capacity of 30% or more whereas the electric supply system typically has reserve margins of 10% to 20%. The 1.6 factor is based on DUA's proprietary data and experience in estimating this relationship.

Given the foregoing, the amount of load that is in play (load that could be served by DG without regard to cost) is 23 MW in 2005, 17.0 MW in 2010, and 18.7 MW in 2015.

Implicit in these load growth estimates is a load growth rate of 3 %/yr for 2003 – 2005, and 2 %/yr after 2005; these figures were provided by NSTAR planning staff.

Generation Capacity Cost

Generation annual capacity cost is the annual cost that would be incurred to own generation capacity on the margin (to serve load growth) if the DG were not used. The values assumed, shown in Table 1, are based on information from NEPOOL.

Table 1. System Information

System Load	2005	2010	2015
Cape Light Total Peak Load (MW)	494	543	597
Load Growth Rate (%/Year)	3.0%	2.0%	2.0%
Distribution Capacity / Central Capacity	1.6		
Cape Light Total Peak Load (MW)	14.4	10.6	11.7
Cape Light Load In-Play (MW)	23.0	17.0	18.7
Generation Capacity Cost			
Baseload Capacity Value, NEPOOL ($/kW-yr)	30.0	43.8	43.8
Peak Generation Capacity Value ($/kW-yr)	30.0	43.8	43.8
Electric Energy Cost			
"Super"-Peak Energy Price (hours per year)	160	160	160
$/MWh	100.0	100.0	100.0
Peak Energy Price (hours per year)	1,725	1,725	1,725
$/MWh	53.0	55.0	61.2
Non Peak Energy Price (hours per year)	6,875	6,875	6,875
$/MWh	33.4	36.7	39.0
T&D Capacity Cost			
Transmission Capacity Cost ($/kW)	12.1	12.1	12.1
Transmission Fixed Charge Rate (utility)	.1300	.1300	.1300
Annual Transmission Capacity Cost ($/kW-yr)	1.6	1.6	1.6
Distribution Capacity Cost ($/kW)	32.7	32.7	32.7
Distribution Fixed Charge Rate (utility)	.1300	.1300	.1300
Annual Distribution Capacity Cost ($/kW-yr)	4.3	4.3	4.3
Portion of D Cost for Substation	50.0%	50.0%	50.0%
I^2R Losses			
On-Peak (%)	8.4%	8.4%	8.4%
Off-Peak (%)	8.2%	8.2%	8.2%
Reliability			
Value-of-Service - Composite ($/kWh)	3.0	3.0	3.0
System Average Interruption Duration Index (SAIDI) (min/year)	130	130	130
Annual Outage Hours (Hours/Year)	2.17	2.17	2.17
Portion of Outages Beyond Substation	99.0%	99.0%	99.0%
Air Emissions Factors (lb/MWh)			
Peak Load CO_2	930	950	950
NOx	0.9	0.9	0.9
Baseload CO_2	1,013	968	1,040
NOx	0.7	0.7	0.7

Electric Energy Cost

The prevailing period-specific price for electric energy is used to estimate the value of electric energy produced by DG. Three price periods are represented in Table 1. They are: Super peak, Peak, and Non-peak. For each price period, the annual number of hours and the average prevailing price are shown.

T&D Capacity Cost

The average total upgrade costs for transmission and distribution capacity are shown in Table 1: 1.6 $/kW-yr for transmission and 4.3 $/kW-yr for transmission. These costs represent NSTAR's currently anticipated total costs associated with upgrading transmission and distribution equipment to serve new load. Note that these are average costs associated with upgrades to T&D capacity; the actual costs for specific projects will likely vary from the average, being lower than the average in some locations, and higher in other locations.

The values used for total installed transmission and distribution costs are based on capital budgets for capacity upgrades ($) divided by the amount of load carrying capacity (MW) added by the upgrade projects.

The T&D fixed charge rate of 0.13 (shown in Table 1) is applied to the total (installed) cost of T&D capacity to calculate the annual financial carrying charges. Fixed charge rates are used to calculate an annuity equivalent of the lifecycle carrying charges for capital equipment. They reflect the effects of cost of capital (a mix of debt and equity), return of capital, income taxes (including depreciation), property tax and insurance. Using the fixed charge rate converts payment streams for the criteria listed above into an annuity equivalent.

Note the criterion labeled as "Portion of Outages Beyond Substation." Based on proprietary data, DUA assumes that approximately 50% of total distribution upgrade cost is for equipment upgrades to substations, including upgrades such as tap changers and additional transformer capacity. Further, it is assumed that the balance of costs are for "feeder" upgrades, involving equipment upgrades downstream from the substation.

The implication is that DGs located at a substation offset half of total distribution upgrade costs and locating DGs downstream from substations (feeder locations) allows the utility to avoid the entire cost associated with a distribution upgrade.

The estimated values for transmission and distribution upgrades, 1.6 and 4.3 $/kW-yr respectively, are relatively low (compared, for example, to industry averages).

For context, consider the T&D costs estimated for a recent study by the Edison Electric Institute that reflect the national average [Ref. 3]: 12.1 $/kW-yr for transmission and 22.6 $/kW-yr for distribution. Nationally, load-growth-related distribution upgrade costs exhibit a fairly wide range about the average, and distribution costs of 30 $/kW-yr and higher are common. When national average T&D costs are used in this study, values of 12.1 $/kW-yr for transmission and 30.0 $/kW-yr for distribution are used.

Please see Section 3 for more details about how the T&D costs from current NSTAR data compare to national average costs.

The transmission-related upgrade costs assumed in this study do not include any transmission access charges or future transmission congestion charges that may apply.

I^2R Losses

When electricity is transmitted through T&D wires there are energy losses, often referred to as I-squared-R (I^2R) losses, where I is current in the line and R is the resistance of the line. The values assumed in this study are shown in Table 1, and derived from values posted on the NSTAR Web site [www.nstaronline.com]. These losses have the effect of increasing the total cost to deliver electricity. If, for example, energy costs 100 $/MWh and total system I^2R losses are 8%, then the net cost for energy delivered is approximately 100 ÷ (1 - .08) = 108.7 $/MWh.

Reliability

DGs may improve service reliability if they can be used to serve loads when grid power is not available. To represent the benefit, a composite value of service (VOS) of 3.0 $/kWh of unserved energy is used. Note that this is a relatively low number. VOS can be much higher, depending on the customer class, amount of equipment damage, lost productivity, and damaged product that results [Ref. 2].

Though it is difficult to generalize this criterion, to represent the total annual cost (avoided) for this study the value of service figure is multiplied by the number of annual hours of outage. From Table 1, the annual duration of outages is assumed to be about 130 minutes (2.17 hours per year). Therefore, 2.17 hr/yr * 3 $/kWh = 6.5 $/kW-yr, representing the reliability benefit if DG can prevent this loss of service.

Readers should note that this estimate is really only a modest placeholder for the actual financial benefit that may accrue in any given circumstance. And though it is clear that avoided outages do indeed have financial value to end-users, from the utility perspective this reliability benefit is elusive: utilities cannot internalize the financial benefit.

Under current regulations, generally as long as utilities maintain some specified level of reliability and/or follow specific design and maintenance protocols, no actual cost (i.e., penalty) associated with outages is incurred by the utility. The result is that costs associated with outages are actually borne by electricity end-users, and ultimately by society at large. However, if utilities or other energy services providers could provide differentiated types of electric service, such as offering various levels of reliability, then this benefit could be internalized by the utility via prices.

Another consideration with respect to improved service reliability and use of DGs is that DGs must be located on-site, serving specific loads. Currently, in most if not all utility systems, a DG is not allowed to export power via the utility distribution system when the utility supply is down (e.g., when a utility outage occurs). If a DG were to supply part of the distribution system that is electrically disconnected from the utility grid, a situation known as “islanding,” then significant safety issues to utility workers and customers in the islanded network would arise, and re-connection of the island to the utility grid is problematical. Until interconnection standards and practices address islanding, DGs must be engineered to disconnect from the grid when islanding conditions occur, and cannot be used to augment grid reliability. (Customers, of course, are free to operate DGs to serve their own loads when disconnected from the grid.)

Also shown in Table 1, 99% of all outages are assumed to occur downstream from the substation. As a result, DGs located at a substation are assumed to provide only 1% of any benefit associated with reduced outages. DGs at feeder locations (at or near loads served) allow the utility to avoid the entire cost associated with outages.

The approach used assumes a perfectly reliable DG. Though DGs are obviously not 100% reliable (i.e., not available every time they are called upon to operate), in the context of this high-level evaluation of DG economic market potential the reliability of DGs is not addressed explicitly. Of course, for any given circumstance, DG reliability may be an important criterion of merit. Readers should also note that state-of-the-art DGs are indeed very reliable.

Air Emissions Factors

Air emission factors are the amount of a given emission per MWh of energy generated. Emission factors in lb/MWh for the NEPOOL generation fleet are provided for CO_2 and NO_X [Ref. 4]. Values are provided for peak and for baseload generation.

Total Utility Avoided Cost

Ultimately the cost to own and to operate a DG is compared to the cost that would be incurred by the utility to provide service to a given kW of load, if the DG is not used. In this context it is referred to as the utility avoided cost, or simply avoided cost.

Primary elements of the avoided cost are: 1) additional generation capacity needed, if any, 2) electric energy (fuel), 3) additional transmission capacity needed, if any, 4) additional distribution capacity needed, if any, 5) T&D I^2R losses, and 6) costs related to maintaining accepted levels of system reliability.

All values used to calculate avoided cost elements are provided in Table 1 in the previous section.

Avoided cost elements and total avoided cost (if DG is used) are shown in Tables 2 and 3 for the years 2005, 2010 and 2015. Table 2 contains results for DGs used for peaking (capacity) and Table 3 contains results for DGs used for baseload applications.

In both tables avoided costs are provided for DGs located at substations (i.e.; for costs up to and including the substation), and b) for DGs located at feeder locations (i.e.; downstream from the substation, at or near loads). Note that utility avoided costs are always higher at feeder locations because more of the distribution upgrade costs can be avoided by the use of DG at these locations.

Avoided Costs, Peak Load

Table 2. Avoided Costs, Peak Load ($/kW-yr, unless otherwise specified)

Cost Item		2005	2010	2015
Generation Capacity		30.0	43.8	43.8
Super Peak Energy Hours/Year		160	160	160
Super Peak Energy Cost*		17.5	17.5	17.5
Peak Energy Hours/Year		40	40	40
Peak Energy Cost*		2.3	2.4	2.7
Non-Peak Energy Hours/Year		0	0	0
Non-Peak Energy*		0.0	0.0	0.0
Energy Total*		19.8	19.9	20.1
Transmission Capacity		1.6	1.6	1.6
Substation Capacity		2.1	2.1	2.1
Distribution Capacity, Entire		4.3	4.3	4.3
Service Reliability	Substation	0.07	0.07	0.07
(Avoided Outages)	Feeder	6.50	6.50	6.50
Total @ Substation		**53.5**	**67.4**	**67.7**
Total (including Feeder)		**62.1**	**76.0**	**76.3**

Avoided Costs, Baseload

Table 3. Avoided Costs, Baseload ($/kW-yr, unless otherwise specified)

Cost Item		2005	2010	2015
Generation Capacity		30.0	43.8	43.8
Super Peak Energy Hours/Year		160	160	160
Super Peak Energy Cost*		17.5	17.5	17.5
Peak Energy Hours/Year		1,725	1,725	1,725
Peak Energy Cost*		99.8	103.6	115.3
Non-Peak Energy Hours/Year		2,495	2,495	2,495
Non-Peak Energy*		91.0	100.0	106.2
Energy Total*		208.3	221.0	238.9
Transmission Capacity		1.6	1.6	1.6
Substation Capacity		2.1	2.1	2.1
Distribution Capacity, Entire (w/Feeder)		4.3	4.3	4.3
Service Reliability	Substation	0.1	0.1	0.1
(Avoided Outages)	Feeder	6.5	6.5	6.5
Total @ Substation		**242.0**	**268.6**	**286.5**
Total (including Feeder)		**250.6**	**277.1**	**295.1**

*Adjusted for I^2R Losses.

Alternative Avoided Costs Assumption

<u>Statistical Representation of Distribution Costs</u>

Figure 1 illustrates how the avoided peak costs could have been modeled statistically, given that the distribution upgrade costs are represented as a log-normal distribution with a minimum value of 0 and a mean value of 4.3 $/kW-yr (NSTAR value [Ref. 1]).

This "broadening" of the distribution avoided costs still leaves the benefits well below the cost of owning and operating a DG. Therefore, this cumbersome statistical approach was not employed in the analysis, and instead the more straightforward and equally valid B/C ratio method was used.

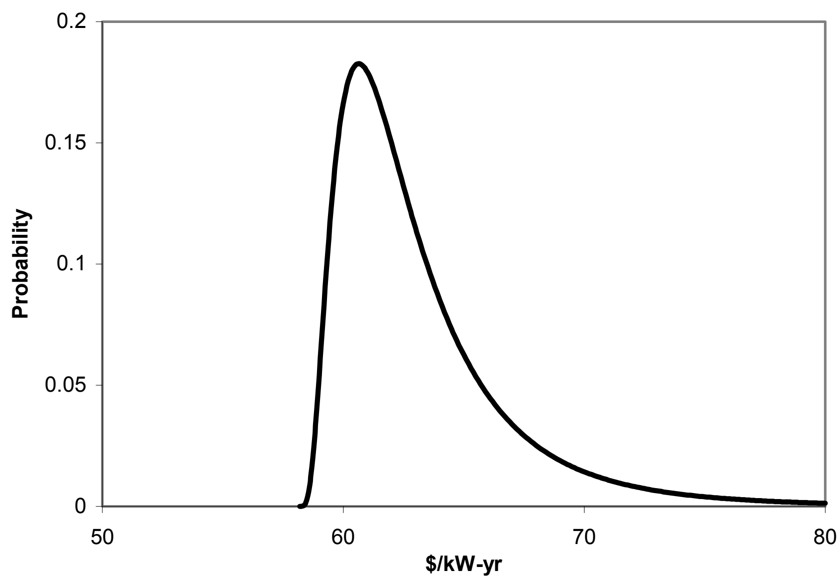

Figure 1. Distribution of Avoided Utility Peak Costs, 2005

<u>National Average Distribution Costs</u>

Another approach is to assume "national average" T&D upgrade costs when doing the B/C evaluations. Values of 12.1 $/kW-yr for transmission and 30.0 $/kW-yr for transmission were derived by DUA [Ref. 3] from national data recently published by EIA. These values are higher than current NSTAR data (1.6 and 4.3 $/kW-yr for T&D, respectively), and may be indicative of the costs of future infrastructure upgrades.

DG-related Assumptions

DG Fixed Charge Rate

The fixed charge rate for utility-owned DGs is 0.15. It is higher than that used for T&D (0.13), primarily because the depreciation period is assumed to be much shorter. In addition, utility financial decision-makers may ascribe greater financial risk to DG purchases until they are more familiar with DG, and until use of DGs is common practice.

DG Fuel Price ($/MMBtu)

Three fuel prices are used. For DGs located at the utility substation "city gate" prices are assumed for natural gas fuel for DGs. These are what might be characterized as utility/wholesale purchase prices. They are somewhat higher than prices paid by owners of larger generation plants.

For DGs located at feeder locations, the prevailing retail price for natural gas for industrial/commercial customers is used. For Martha's Vineyard propane fuel is assumed.

Table 4. Distributed Generation Fuel Prices

DG Fuel Price ($/MMBtu)			
Natural Gas, "City Gate"	3.32	3.46	3.55
Natural Gas, Commercial/Industrial	7.55	7.87	8.07
Propane	15.73	16.39	16.82

DG Operation Hours Per Year

In most cases DGs operated for 200 hours per year can serve peaking or capacity applications. In many cases such DGs can reduce peak demand on the distribution system by as much as 10%. For this study, a simplifying assumption is that the 200 hours occur during the system peak; the results are insensitive to this assumption.

Given an estimated annual average customer load factor of 0.552 (derived from NSTAR data), DG baseload operation is defined as the annual full load equivalent hours of 0.552 * 8,760 hours per year = 4,380 hours per year.

DG Cost and Performance

Six DG technologies were evaluated: 1) Phosphoric-acid Fuel Cell, 2) Advanced Fuel Cell, 3) PEM Fuel Cell, 4) microturbine, 5) Spark/Otto engine using natural gas and 6) Spark/Otto engine using propane.

For each technology description, the key data points are:

- size or size range (kW)
- year
- capital cost ($/kW)
- installed cost ($/kW), inclusive of: labor, materials, engineering, instrumentation and metering, overhead, interconnections, etc., but exclusive of air permitting, utility studies, or other
- heat rate (Btu/kWh), high heating value (HHV)

- variable O&M costs ($/kWh)
- fixed O&M costs ($/kW-yr)
- NO_X and CO_2 emissions factors (lb/MWh)

Details about the technology assumptions used for this study are shown in Tables 5 through 10. Complete technology data sets are given in the tables in Appendix A.

Table 5. Detailed Assumptions for Phosphoric-acid Fuel Cells

Phos-acid Fuel Cell		2005	2010	2015
	Installed Cost ($/kW)	4,250	3,125	2,000
	Heat Rate (Btu/kWh)	8,420	8,000	7,575
	Variable O&M ($/kWh)	0.01	0.01	0.01
	Fixed O&M ($/kW-yr)	10	7.5	5
Emission	CO_2 (lb/MWh)	850	810	760
Factors	NOx (lb/MWh)	0.033	0.031	0.03
Fuel	@ Substation ($/MMBtu)	3.32	3.46	3.55
Price	@ Feeder ($/MMBtu)	7.55	7.87	8.07

Table 6. Detailed Assumptions for Advanced Fuel Cells

Advanced Fuel Cell		2005	2010	2015
	Installed Cost ($/kW)	3,200	1,350	550
	Heat Rate (Btu/kWh)	6,890	8,420	6,315
	Variable O&M ($/kWh)	0.01	0.01	0.01
	Fixed O&M ($/kW-yr)	10	7.5	5
Emission	CO_2 (lb/MWh)	950	950	710
Factors	NOx (lb/MWh)	0.055	0.055	0.041
Fuel	@ Substation ($/MMBtu)	3.32	3.46	3.55
Price	@ Feeder ($/MMBtu)	7.55	7.87	8.07

Table 7. Detailed Assumptions for PEM Fuel Cells

PEM Fuel Cell		2005	2010	2015
	Installed Cost ($/kW)	4,000	2,750	1,500
	Heat Rate (Btu/kWh)	7,575	7,230	6,890
	Variable O&M ($/kWh)	0.01	0.01	0.01
	Fixed O&M ($/kW-yr)	10	7.5	5
Emission	CO_2 (lb/MWh)	950	910	860
Factors	NOx (lb/MWh)	0.033	0.031	0.03
Fuel	@ Substation ($/MMBtu)	3.32	3.46	3.55
Price	@ Feeder ($/MMBtu)	7.55	7.87	8.07

Table 8. Detailed Assumptions for Microturbines

Microturbine		2005	2010	2015
	Installed Cost ($/kW)	940	825	625
	Heat Rate (Btu/kWh)	13,540	10,820	9,435
	Variable O&M ($/kWh)	0.01	0.0047	0.0047
	Fixed O&M ($/kW-yr)	0	0	0
Emission Factors	CO_2 (lb/MWh)	1,190	950	830
	NOx (lb/MWh)	0.544	0.0777	0.0677
Fuel Price	@ Substation ($/MMBtu)	3.32	3.46	3.55
	@ Feeder ($/MMBtu)	7.55	7.87	8.07

Table 9. Detailed Assumptions for Natural Gas Fueled Engines

Natural Gas Engine		2005	2010	2015
	Installed Cost ($/kW)	780	780	780
	Heat Rate (Btu/kWh)	9,970	9,970	9,970
	Variable O&M ($/kWh)	0.011	0.011	0.011
	Fixed O&M ($/kW-yr)	0	0	0
Emission Factors	CO_2 (lb/MWh)	840	840	840
	NOx (lb/MWh)	0.25	0.25	0.25
Fuel Price	@ Substation ($/MMBtu)	3.32	3.46	3.55
	@ Feeder ($/MMBtu)	7.55	7.87	8.07

Table 10. Detailed Assumptions for Propane Fueled Engines

Propane Engine		2005	2010	2015
	Installed Cost ($/kW)	820	820	820
	Heat Rate (Btu/kWh)	9,970	9,970	9,970
	Variable O&M ($/kWh)	0.011	0.011	0.011
	Fixed O&M ($/kW-yr)	0	0	0
Emission Factors	CO_2 (lb/MWh)	840	840	840
	NOx (lb/MWh)	0.25	0.25	0.25
Fuel Price	@ Substation ($/MMBtu)	15.73	16.39	16.82
	@ Feeder ($/vMMBtu)	15.73	16.39	16.82

Section 3. Methodology

Economic Evaluation Using Benefit/Cost Ratio Analysis

A key objective of this project is to estimate the potential for investment in economically viable distributed generation as an alternative or augmentation to investment in transmission and distribution. This is accomplished by performing a benefit/cost analysis for specified applications of DG operating in utility modes. The total yearly costs to own and operate the DG for a given application are calculated, and compared to the total yearly benefits to be achieved by that operation. If the ratio of benefits to costs exceeds 1.0, then the DG is considered economically competitive for that application. The higher the ratio, the more economically attractive DG will be for that application. In addition, "break-even" distribution costs for the various technologies are estimated, defined as the distribution cost point at which the B/C ratio equals 1.0.

The total cost to own and operate a DG includes purchase and installation costs, fuel expenses, financing, and operating and maintenance (O&M) costs; some of these costs are dependent upon the number of hours of operation per year, and will be defined by the specific application. Benefits ascribed to the DG will include avoided energy costs, capacity deferral (generation, transmission and distribution), loss reduction, reliability enhancement, and possibly others, as applicable to a given situation.

For this analysis, DUA used DG cost and performance data that was acquired from equipment manufacturers and has been verified in practice. Benefits include avoided cost values of 4.3 $/kW-yr for distribution capacity and 1.6 $/kW-yr for transmission capacity. These figures were derived from NSTAR data for planned T&D capital expenditures [Ref. 1], and represent marginal transmission and distribution capacity costs that are much lower than typical utility or national average values. Other benefits included avoided energy costs of 19.8 $/kW-yr, and service reliability improvement of 6.5 $/kW-yr. (For a detailed description of assumptions, and the resultant benefits as functions of substation/feeder location and year, please see Section 2).

As described in Section 2, the maximum potential size of the market for distributed generation is defined as the load in play – load that could be served by DG without regard to cost. From Table 1, load in play for the Compact is 23 MW in 2005, 17.0 MW in 2010, and 18.7 MW in 2015. This represents new load due to load growth, which DG could serve if it were economic, thereby avoiding the need to expand the existing utility infrastructure. DG is not being considered for serving existing load, as there would be fewer utility costs to avoid.

Utility Operational Modes: Peaking and Baseload

Economic evaluations are performed for both peaking and baseload operation modes. The distributed generation is assumed to be sited at substation or feeder locations (i.e., at or near loads), thereby capturing the benefit of avoided transmission and distribution costs.

To serve as a peaking resource, a distributed generator must reduce utility infrastructure capacity needs. That, in turn, requires distributed generation to be operational during the utility's peak demand hours: the 100 - 200 hours or so during the year when demand for electricity is highest. The level of power draw on the utility system from all customers during those times dictates the required maximum capacity of the utility's generation system.

This concept is important for the analysis because the degree to which a distributed generator allows the utility to avoid procurement of additional capacity determines the "capacity benefit" associated with distributed generation. Stated another way, to the extent that distributed generators operate to offset the need for new/upgraded utility electric grid capacity, they receive a capacity credit commensurate with the amount of otherwise needed utility generation, transmission and/or distribution equipment (capacity, infrastructure). Note that because peaking distributed generators operate for so few hours per year, their total variable operating costs in the evaluation are much less than their total capital costs.

Baseload distributed generators operate for thousands of "full load equivalent" hours per year, in this case 4,380 hours per year. They can also receive the capacity credit described above if they generate during the utility's peak demand hours. But for baseload distributed generators, it is usually more important to consider the cost of production for electric or thermal energy.

Because they operate for many hours per year, baseload distributed generators must compete primarily on an "energy" (i.e., variable) cost basis. (By contrast, the key criterion of merit for peaking units is "capacity" cost, a fixed cost.) During most of the year, the competition for baseload distributed generators is represented by lower-cost commodity electricity from the wholesale electric marketplace. That marketplace is dominated by large generation facilities with economies of scale and generally low incremental costs of production.

Therefore, installed capital cost and cost of production are both key criteria driving a baseload distributed generator's economic competitiveness. In turn, a baseload distributed generator's net cost of production is driven by fuel efficiency, fuel price, variable operations and maintenance costs for the particular distributed generator, and the degree to which waste heat can be sold for cogeneration.

Utility Locations: Substation and Feeder

As depicted graphically in Figure 2, the DUVal model evaluates distributed generators at two location types: 1) at a utility substation, and 2) on a distribution feeder at or near a customer's site.

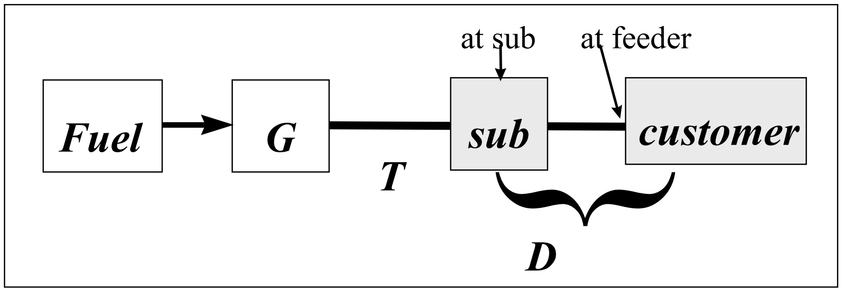

Figure 2. DUVal Evaluation Nodes

Several key factors distinguish these two types of locations:

- Because most electric service outages occur between the substation and the load, a distributed generator sited at the substation does not receive as substantial a credit for reliability increases as does a distributed generator located on the feeder or at the customer's site.
- Distributed generators at substations do not defer the need for a feeder and thus do not receive an avoided cost credit for the cost of a feeder.
- Distributed generators at a substation are assumed to be larger and to qualify for purchase of gas at a wholesale/power plant procurement price; distributed generators on the feeder are assumed to use gas whose prices are higher because purchases are at a lower-volume, "retail" level.

It is assumed that the required fuel type and distribution infrastructure are available at all sites considered.

Alternative Economic Evaluation Using National Average T&D Costs

As mentioned above, T&D avoided cost estimates derived from NSTAR planning data are low compared to typical T&D costs, and to national average costs. NSTAR currently anticipates very few T&D upgrade projects over the next few years [Ref. 1]. This will result in relatively few utility locations where DG could be considered.

Since this study has a longer term perspective (to 2015), the authors contend that DG should be considered as an important option in the future, should T&D conditions change. If, for example, load growth in the region accelerates and more T&D upgrades are in fact needed, those upgrades may well be more expensive than the projects currently planned by NSTAR.

Therefore, an additional evaluation was performed using national average T&D costs (derived from EIA data reported by utilities in the United States) in the benefits calculation. The national average transmission upgrade cost (to serve load growth) was estimated to be 12.1 $/kW-yr, whereas costs for NSTAR were 1.6 $/kW-yr. The national average distribution upgrade cost was estimated to be 12.1 $/kW-yr, compared to 1.6 $/kW-yr for NSTAR.

[Note: After performing the entire economic analysis, NSTAR data for historical T&D capital expenditures for the five-year period from 1998 to 2008, including specific costs for the Cape and Vineyard, were filed with the Massachusetts Department of Telecommunications and Energy, the state regulatory agency. A preliminary analysis showed that yearly T&D costs derived from these data were consistent with (i.e., within about 20% of) the national average T&D values quoted above.

Economic Evaluation Using Statistical Analysis

For most utilities, the cost (in $/kW) to install T&D infrastructure upgrades will vary due to a number of factors, not the least of which is location: it will more expensive to serve some areas than others. Therefore, the avoided cost benefits for DG will be represented, not by a single number or a very narrow range, but by a statistical spread of costs. This variability of avoided costs requires an evaluation tool such as DUVal, DUA's proprietary market estimation model.

DUVal calculates the economic market potential for utility owned and operated distributed generation by using financial and economic criteria that are commonly accepted by electric utility planners and engineers to evaluate the costs and benefits associated with use of distributed generators.

As illustrated in Figure 3, to make the economic market potential estimates, the DUVal model compares the annualized net <u>cost</u> to own and operate the DG to a statistically defined range of annualized <u>benefits</u> associated with use of the DG. The amount of potential market for which the DG is less expensive than the benefits represents its *market potential*.

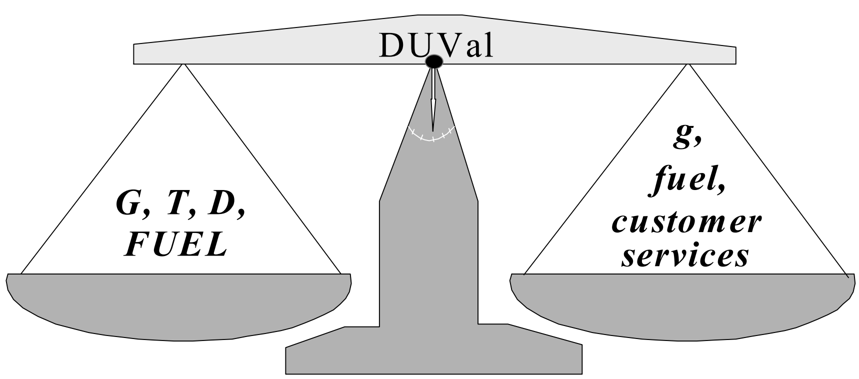

Figure 3. DUVal Evaluation—Utility Perspective

Cost of ownership for DGs includes purchase, installation, financing, depreciation expenses, taxes, fuel, maintenance, and fixed costs such as periodic overhauls and insurance.

Utility benefits associated with the use of distributed generators are utility/grid-related costs that will not be incurred by the utility (i.e., are an "avoided cost") if the distributed generator is used in lieu of the central/grid solution. This assumes, of course, that the distributed generator can provide the same or better service reliability and power quality. In other words, for the utility, the benefit associated with use of a distributed generator is the avoided cost for otherwise needed fuel, O&M and overhead expenses, and generation, transmission and distribution capacity (equipment) costs.

(Note: even if a project is merely deferred rather than avoided altogether, the time value of money often makes it worthwhile to use temporary, redeployable, modular, and less financially risky distributed generation options rather than a more typical "lumpy" grid upgrade.)

Variability of Utility Avoided Cost

The DUVal model uses a statistical representation of the *range* of utility avoided costs throughout the service area and among locations. Utility avoided costs, defined as those costs avoided if distributed generators are used in lieu of the conventional central generation and wires option, vary widely among utilities and even within a given utility's service territory. Needless to say, some locations are inexpensive to serve and others can be quite expensive to serve. These costs are modeled in DUVal as statistical distributions referred to as "value mountains" because of their characteristic shape (shown in Figure 4).

Determination of Economic Market Potential

The total cost to implement a distributed generation option is compared to the value mountain of avoided costs. The economic market potential for a given distributed generation technology corresponds to the total number of locations that are more expensive to serve with central generation than with the distributed technology being analyzed. Economic market potential is expressed as a percentage of "load in play," the maximum amount of load for which the DG is considered technically feasible.

The example figure (Figure 4) includes a value mountain based on national average utility costs, for locations at or near loads, for the peaking duty cycle. The X axis is the avoided cost. The left Y axis indicates the portion of all utility load growth for which a given avoided cost applies. The right Y axis indicates the portion of load growth for which the utility avoided cost exceeds a given amount (point on the X axis).

Estimating economic market potential using Figure 4 involves the following steps:

Point a: Locate the cost ($/kW-yr) for the utility to own and operate a specific DG on the X axis. **Point b:** Locate the point within the *spread* of utility cost-of-service values beyond which a DG's cost is less than the avoided cost (i.e., portion of load growth for which DG is cost-effective). **Point c:** Locate the portion (%) of the load in-play for which the given DG is cost-effective on the chart's secondary/right Y-axis.

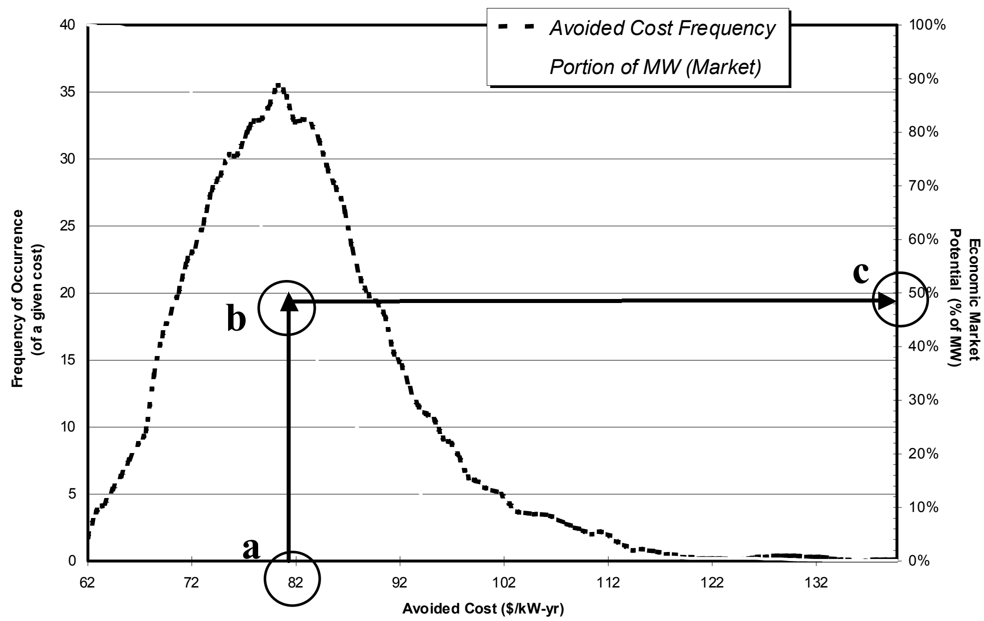

Figure 4. Statistical Spread of Utility Total Avoided Cost and Economic Market Potential ("Value Mountain"), an Example

For the example, the economic market potential is 50%. That is, a DG costing 82 $/kW-yr is the lowest cost alternative for serving 50% of the load in play. If load in play is 100 MW, then economic market potential is 50 MW.

Value Mountains for National Average Costs

The following four figures show value mountains developed using 2002 national average data. There are four value mountains, one each for 1) peak load DG operation at substations, 2) peak load DG operation at feeder locations, 3) baseload DG operation at substations and 4) baseload operation of DGs at feeder locations.

For context, the national average transmission upgrade costs [Ref. 3] were estimated to be 12.1 $/kW-yr, whereas costs derived from NSTAR data were 1.6 $/kW-yr. National average distribution upgrade costs were estimated to be 22.6 $/kW-yr, compared to costs derived from NSTAR data of 4.3 $/kW-yr.

Alternative Utility Peak Duration Assumptions

This analysis uses an assumption that 200 hours of distributed generation operation per year is sufficient to allow the utility to clip distribution and central power peaks. This a standard assumption made by DUA based on examining load patterns on many distribution feeders and performing loss of load probability analysis for central-station power plants (much of that was done to evaluate the value of photovoltaics on utility systems).

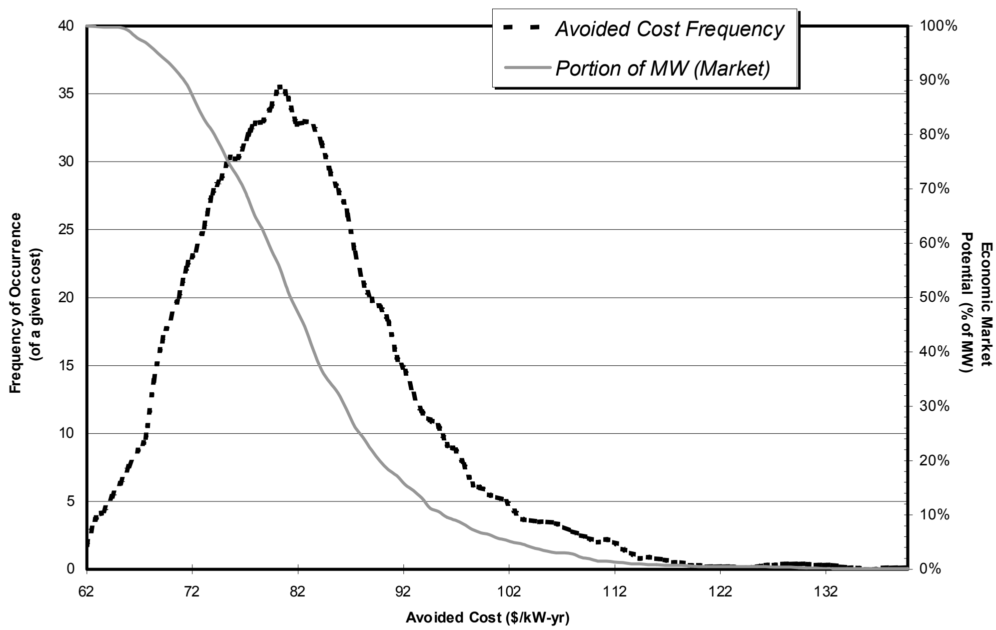

Figure 5. Value Mountains, Peak Load, for DGs located at Substations, Based on National Average Costs

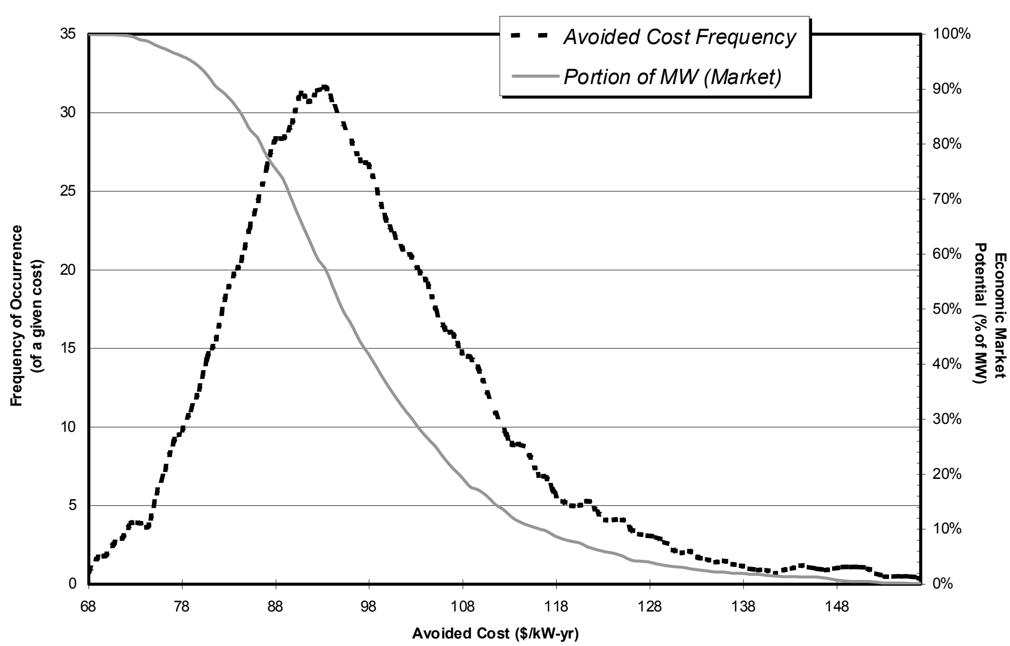

Figure 6. Value Mountains, Peak Load, for DGs located at Feeder Locations, Based on National Average Costs

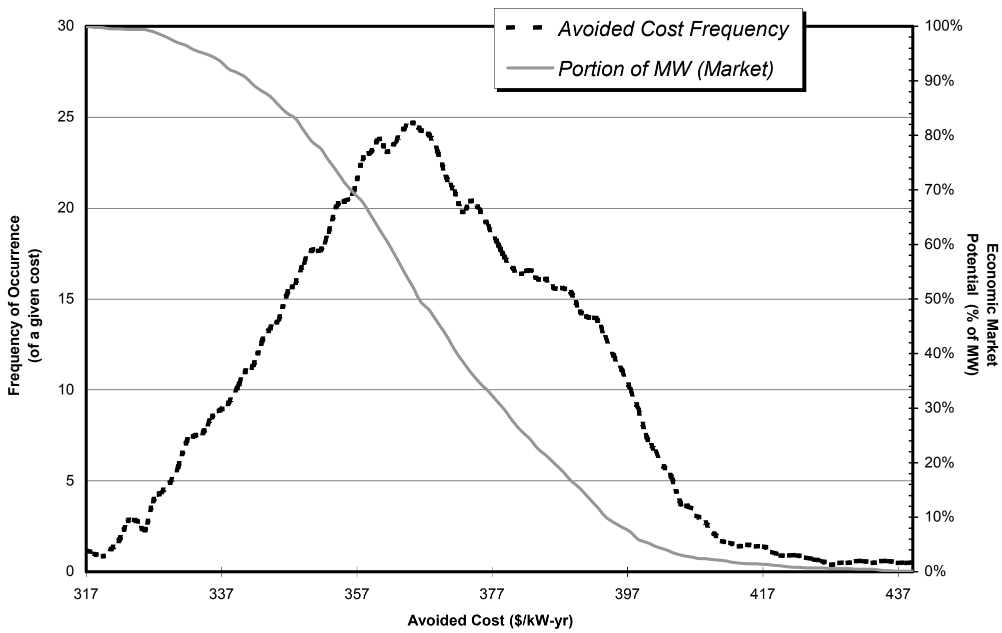

Figure 7. Value Mountains, Base Load, for DGs located at Substation Locations, Based on National Average Costs

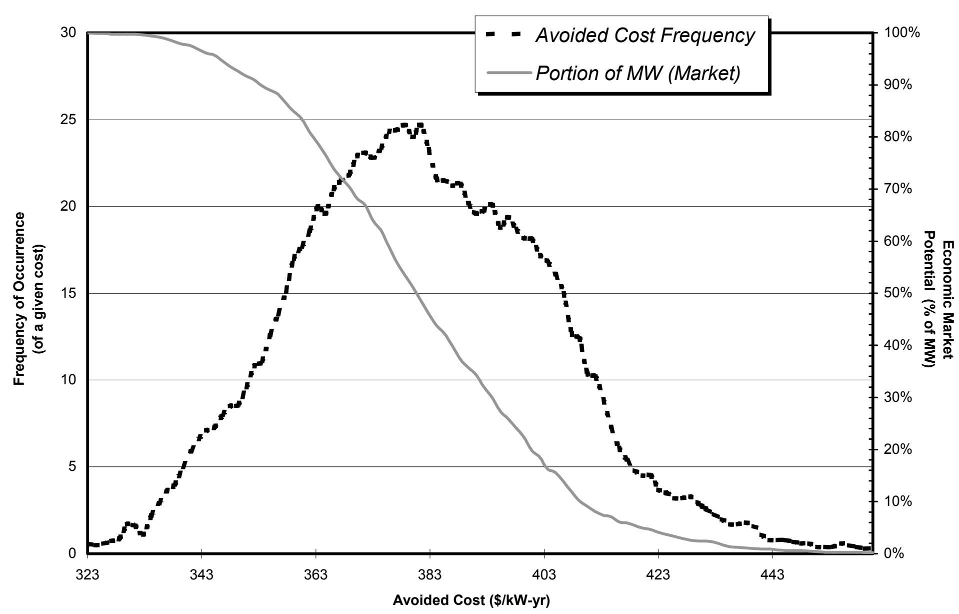

Figure 8. Value Mountains, Base Load, for DGs located at Feeder Locations, Based on National Average Costs

Figure 9 shows a load duration curve for the combined central station loads of the Cape and Martha's Vineyard, created from hourly NSTAR 2000 data. As is typical even in this aggregate view, the peaks are infrequent but severe. If a distributed generation resource were used for just the highest 200 hours to clip the peak, about 80 MW could be installed, clipping about 15% of the peak. No feeder level load data was available, but each feeder is almost certainly more peaky than the sum of the feeders. Thus it would be expected that 200 hours of DG operation would be able to cut well in excess of 15% of the feeder peaks.

In general, distribution feeder loads tend to be much more "peaky" than the aggregate load of the entire utility. Almost by definition, the load diversity of any individual feeder is lower than the utility as a whole. Quite often only 25 hours of operation per year is sufficient to meet 10% of the peak on a feeder.

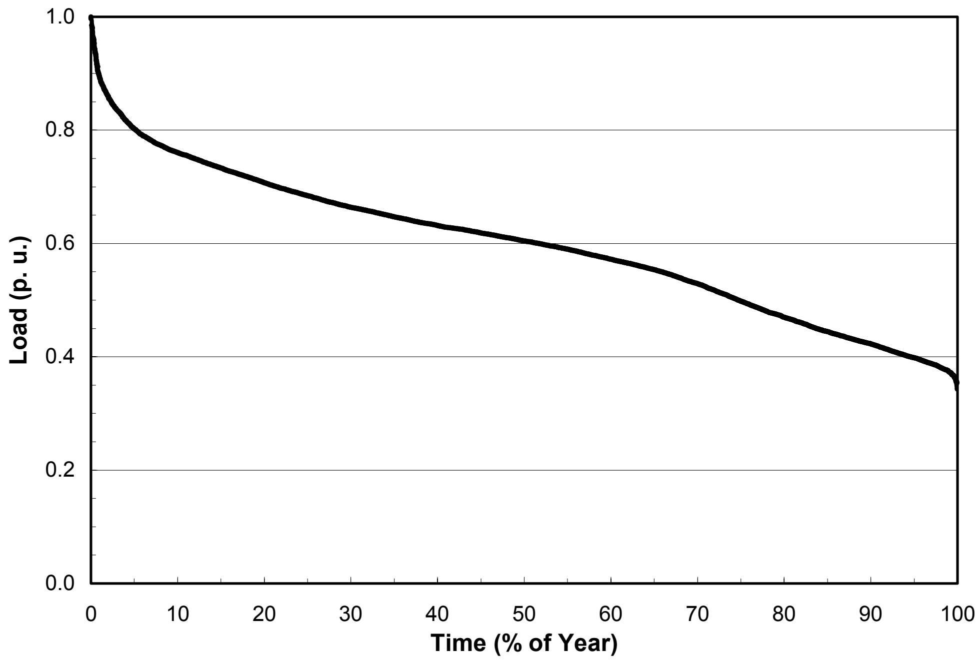

Figure 9. 2000 Load Duration Curve for the Cape Light Compact Communities

From a central-station generation point of view, often a loss of load probability approach is taken to estimate the value of the highest peaks in a year. The vast majority of the capacity value of central-station asset is accrued during the top dozen hours of a year, although this varies from year to year and utility to utility.

Hence the 200 hr/yr assumption appears conservative, if the utility can successfully operate the distributed generation unit during these peaks. But what would be the impact of alternate assumptions on the analysis presented here?

The baseload analysis is not impacted at all by this variable since it is assumed that the distributed generation is operated almost all of the hours of the year. The peaking results will look slightly better with short hours of operation and poorer with longer hours of operation per year to cut these peaks.

During these peak operation hours, the distributed generation incurs fuel costs and operations and maintenance costs, which are counterbalanced by the value of the energy produced. There is no additional capacity value earned by operating more than the 200 hours.

Using the baseline assumption of 200 hours per year, assuming a year 2005 microturbine (with a heat rate of 13,540 Btu/kWh, a fuel cost of 7.55 $/MMBtu, and an operations and maintenance cost of one cent per kWh), the operating costs would be 22.4 $/kW-yr. From Table 2 it can be seen that the energy value of this peaker operation is 19.8 $/kW-yr. On the margin the utility would lose a tiny amount (2.6 $/kW-yr) by operating 200 hours per year as a capacity device, a very small number compared to the total value of that capacity, approximately 62 $/kW-yr.

Using more hours per year for pure peaking needs only makes the economics worse. Using less hours per year, say 100, would roughly make the economics better by 1.3 $/kW-yr, a very small effect. Better heat rates (such as are assumed in 2010 and 2015) will eventually swing this variable into encouraging more hours of operation per year, as is evidenced by the baseload markets looking marginally viable in the out-years.

Section 4. Results

Summary Results

Description

The B/C ratio criterion previously described is used as the primary figure of merit when evaluating the financial merits of using DGs. Evaluations are performed for peaking and baseload applications; for each case, the DG may be located at either the distribution substation or on the distribution feeder, closer to customer loads (see Figure 10).

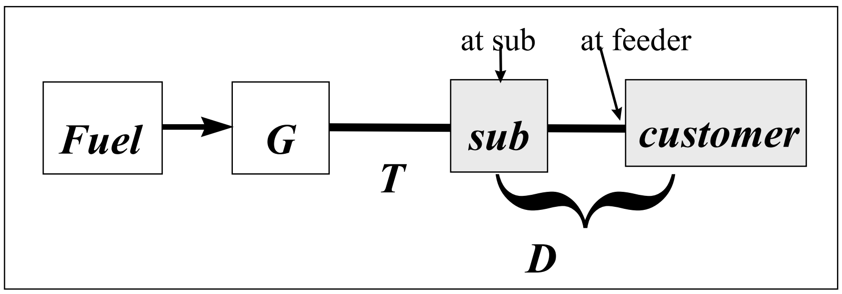

Figure 10. Evaluation Nodes for Distributed Generation

Peaking Mode Distributed Generation Operation

As shown in Figures 11 and 12, there are no DGs for peaking applications that have a B/C ratio exceeding one, for any of the years evaluated. The natural gas engine is the most cost-effective option in 2005, with a B/C ratio of 0.43 at substation locations and 0.46 at feeder locations, and also in 2010, with B/C ratios of 0.53 and 0.56 at substation and feeder, respectively. In 2015 the most cost-effective option is the advanced fuel cell with B/C ratios of 0.72 and 0.76 at substation and feeder, respectively.

Baseload Mode Distributed Generation Operation

As shown in Figures 13 and 14, there are two cases for which DGs have a B/C ratio exceeding one. Both occur in 2015 and at substation locations: the advanced fuel cell has a B/C ratio of about 1.22 and the microturbine has a B/C ratio of about 1.1.

In general, baseload markets are more attractive economically than peaking markets, because the heat rate (efficiency) of the DG comes into play in proportion to the greater baseload operating hours, compared to peak applications.

B/C ratios at feeder locations were substantially below one in all years, for all DGs. The primary reason for this is that the natural gas fuel price assumed for feeder locations (retail delivery price) is much higher than the price assumed at substation locations (city gate price) (please see Section 2 for details). While feeder locations have greater potential benefits due to higher avoided T&D costs, this effect cannot overcome the impacts of higher fuel costs.

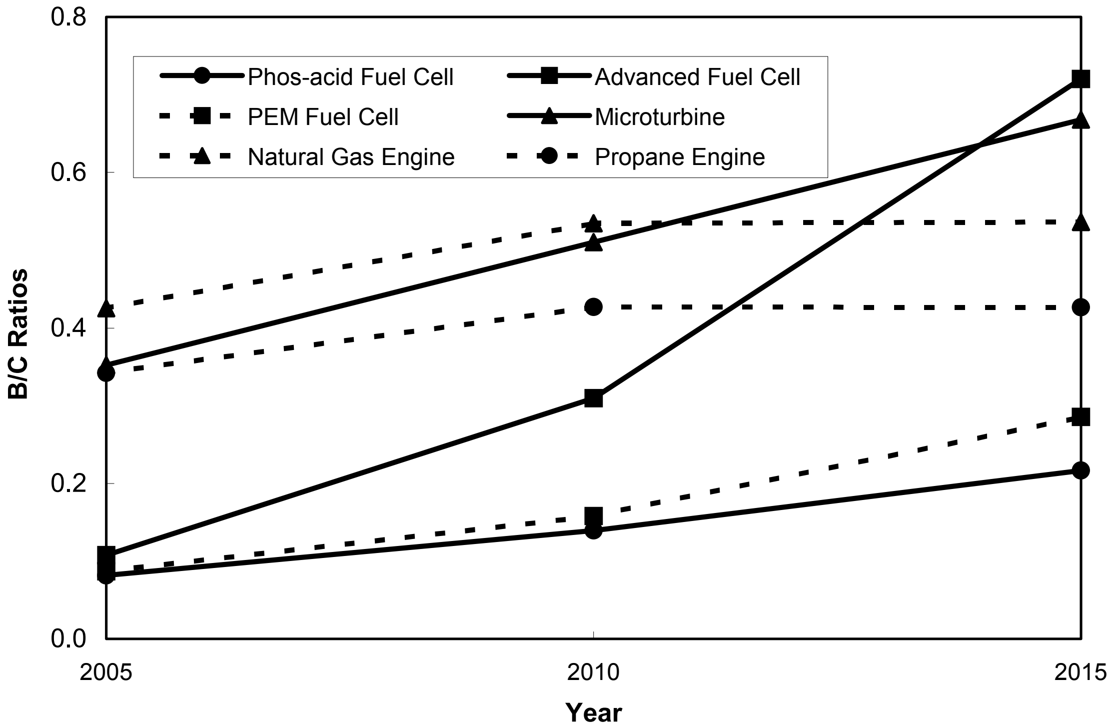

Figure 11. B/C Ratios, Peak Load, @ Substation

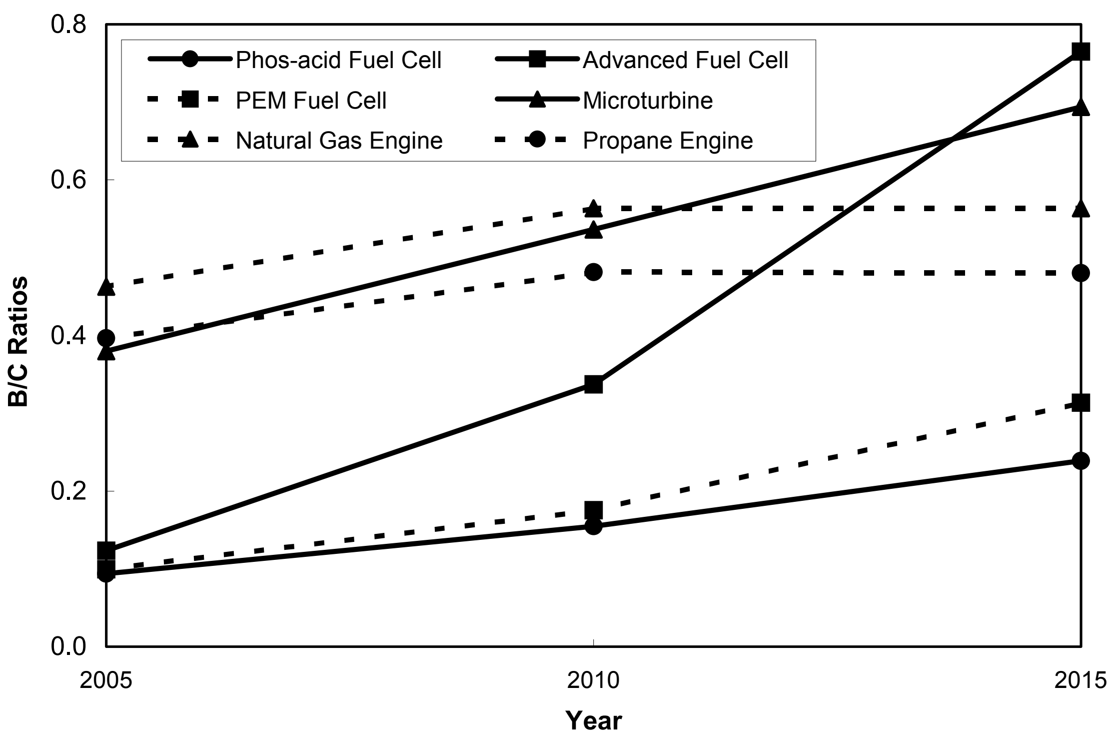

Figure 12. B/C Ratios, Peak Load, @ Feeder Locations

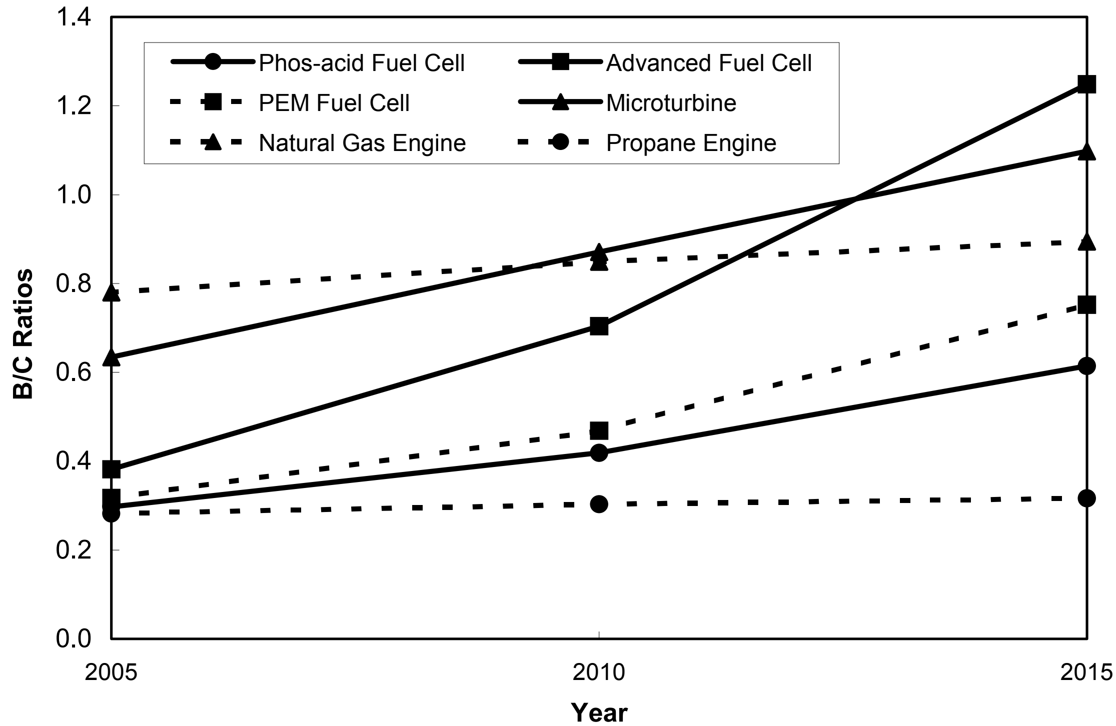

Figure 13. B/C Ratios, Baseload, @ Substation

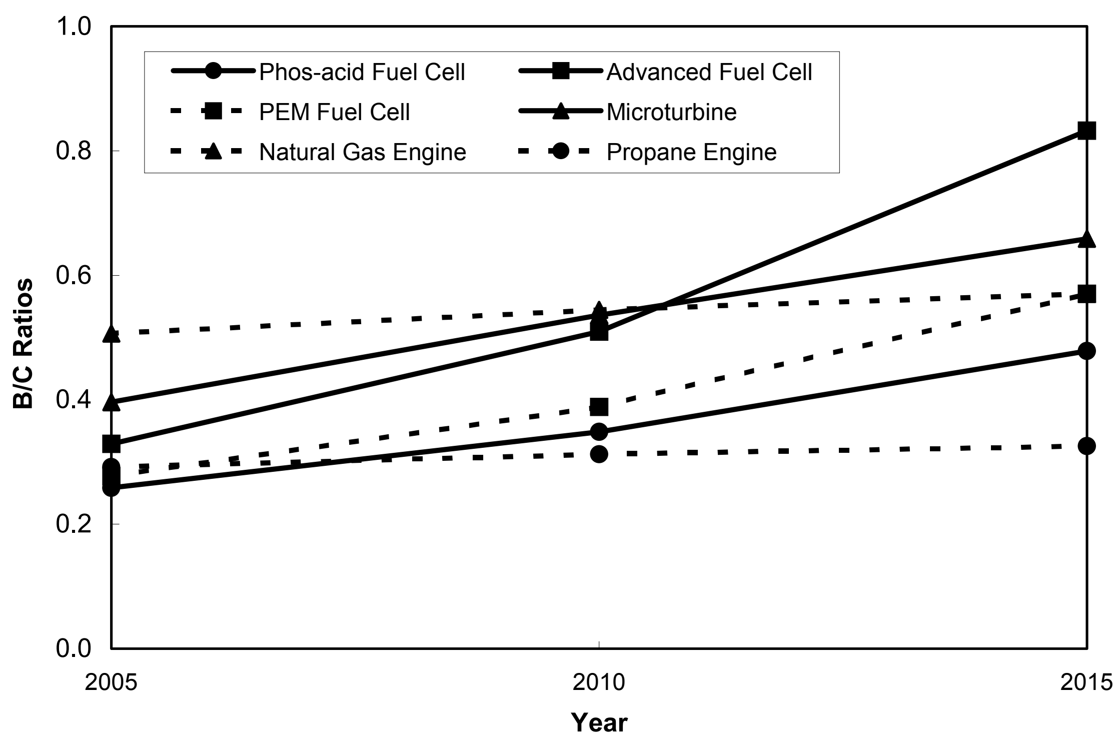

Figure 14. B/C Ratios, Baseload, @ Feeder Locations

Detailed Results

Description

Detailed results for all DG technologies in peaking applications are shown in Tables 11 through 16, and results for baseload applications are shown in Tables 17 through 22. Each table displays results in three columns for the years 2005, 2010 and 2015. For each year the results include:

1. annual DG cost for both substation and feeder locations;
2. benefit/cost (B/C) ratio for both substation and feeder locations;
3. break-even distribution cost for both substation and feeder locations; and
4. CO_2 and NO_X emissions offsets – the percentage difference between estimated DG emissions and average NEPOOL emissions (a negative value means that the DG emissions are less than NEPOOL's by the given percentage)

For example, the first two lines of Table 11 show that in 2005 the annual cost to own and operate a phosphoric-acid fuel cell is 655 $/kW-yr for substation locations and 662 $/kW-yr for feeder locations. Lines 3 and 4 show that the B/C ratio is only 0.08 at substations and 0.09 at feeders, consistent with the high technology cost of the fuel cell. The break-even distribution cost for this case is 604 $/kW-yr, for both locations (lines 5 and 6). (Since the B/C ratio is very low, a very high distribution cost would be required to bring that ratio up to 1.0. Here, a distribution cost of over 600 $/kW-yr is the break-even point for phosphoric-acid fuel cells; finding such a high-cost distribution system location is highly unlikely.) Lastly, estimated CO_2 and NO_X emissions for the DG are 8.6 % and 96.3% lower, respectively, than the estimated emissions from NEPOOL.

Detailed Results, Peak Load

Table 11. Detailed Results for Phosphoric-acid Fuel Cells for Peak Load Applications

Peak Load	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	655	484	312
Annual Cost @ Feeder ($/kW-year)	662	491	319
B/C @ Substation	.08	.14	.22
B/C @ Feeder	.09	.15	.24
Break-even Distribution Cost @ Substation ($/kW-year)	604	418	247
Break-even Distribution Cost @ Feeder ($/kW-year)	604	419	247
Increase/Decrease CO_2	-8.6%	-14.7%	-20.0%
Increase/Decrease NOx	-96.3%	-96.6%	-96.7%

Table 12. Detailed Results for Advanced Fuel Cells for Peak Load Applications

Peak Load	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	497	218	94
Annual Cost @ Feeder ($/kW-year)	502	225	100
B/C @ Substation	.11	.31	.72
B/C @ Feeder	.12	.34	.76
Break-even Distribution Cost @ Substation ($/kW-year)	445	153	28
Break-even Distribution Cost @ Feeder ($/kW-year)	445	154	28
Increase/Decrease CO_2	+2.2%	0.0%	-25.3%
Increase/Decrease NOx	-93.9%	-93.9%	-95.4%

Table 13. Detailed Results for PEM Fuel Cells for Peak Load Applications

Peak Load	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	617	427	237
Annual Cost @ Feeder ($/kW-year)	623	433	243
B/C @ Substation	.09	.16	.29
B/C Onsite	.10	.18	.31
Break-even Distribution Cost @ Substation ($/kW-year)	566	362	171
Break-even Distribution Cost @ Feeder ($/kW-year)	566	362	171
Increase/Decrease CO_2	+2.2%	-4.2%	-9.5%
Increase/Decrease NOx	-96.3%	-96.6%	-96.7%

Table 14. Detailed Results for Microturbines for Peak Load Applications

Peak Load	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	152	132	101
Annual Cost @ Feeder ($/kW-year)	163	142	110
B/C @ Substation	.35	.51	.67
B/C @ Feeder	.38	.54	.69
Break-even Distribution Cost @ Substation ($/kW-year)	101	67	36
Break-even Distribution Cost @ Feeder ($/kW-year)	106	70	38
Increase/Decrease CO_2	+28.0%	0.0%	-12.6%
Increase/Decrease NOx	-39.6%	-91.4%	-92.5%

Table 15. Detailed Results for Natural Gas Engines for Peak Load Applications

Peak Load	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	126	126	126
Annual Cost @ Feeder ($/kW-year)	134	135	135
B/C @ Substation	.43	.53	.54
B/C @ Feeder	.46	.56	.56
Break-even Distribution Cost @ Substation ($/kW-year)	74	61	61
Break-even Distribution Cost @ Feeder ($/kW-year)	76	63	63
Increase/Decrease CO_2	-9.7%	-11.6%	-11.6%
Increase/Decrease NOx	-72.2%	-72.2%	-72.2%

Table 16. Detailed Results for Propane Fueled Engines for Peak Load Applications

Peak Load	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	157	158	159
Annual Cost @ Feeder ($/kW-year)	157	158	159
B/C @ Substation	.34	.43	.43
B/C @ Feeder	.40	.48	.48
Break-even Distribution Cost @ Substation ($/kW-year)	105	93	93
Break-even Distribution Cost @ Feeder ($/kW-year)	99	86	87
Increase/Decrease CO_2	-9.7%	-11.6%	-11.6%
Increase/Decrease NOx	-72.2%	-72.2%	-72.2%

Detailed Results, Base Load

Table 17. Detailed Results for Phosphoric-acid Fuel Cell for Baseload Applications

Baseload	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	814	641	467
Annual Cost @ Feeder ($/kW-year)	970	796	617
B/C @ Substation	.30	.42	.61
B/C @ Feeder	.26	.35	.48
Break-even Distribution Cost @ Substation ($/kW-year)	574	375	182
Break-even Distribution Cost @ Feeder ($/kW-year)	723	523	326
Increase/Decrease CO_2	-16.1%	-16.3%	-26.9%
Increase/Decrease NOx	-95.3%	-95.6%	-95.7%

Table 18. Detailed Results for Advanced Fuel Cells for Baseload Applications

Baseload	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	634	381	229
Annual Cost @ Feeder ($/kW-year)	762	544	355
B/C @ Substation	.38	.70	**1.25**
B/C @ Feeder	.33	.51	.83
Break-even Distribution Cost @ Substation ($/kW-year)	394	115	n/a
Break-even Distribution Cost @ Feeder ($/kW-year)	515	271	64
Increase/Decrease CO_2	-6.2%	-1.9%	-31.7%
Increase/Decrease NOx	-92.1%	-92.1%	-94.1%

Table 19. Detailed Results for PEM Fuel Cells for Baseload Applications

Baseload	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	764	573	381
Annual Cost @ Feeder ($/kW-year)	904	713	517
B/C @ Substation	.32	.47	.75
B/C @ Feeder	.28	.39	.57
Break-even Distribution Cost @ Substation ($/kW-year)	524	307	97
Break-even Distribution Cost @ Feeder ($/kW-year)	658	440	227
Increase/Decrease CO_2	-6.2%	-6.0%	-17.3%
Increase/Decrease NOx	-95.3%	-95.6%	-95.7%

Table 20. Detailed Results for Microturbines for Baseload Applications

Baseload	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	382	308	261
Annual Cost @ Feeder ($/kW-year)	633	517	448
B/C @ Substation	.63	.87	**1.10**
B/C @ Feeder	.40	.54	.66
Break-even Distribution Cost @ Substation ($/kW-year)	142	42	n/a
Break-even Distribution Cost @ Feeder ($/kW-year)	386	244	157
Increase/Decrease CO_2	+17.5%	-1.9%	-20.2%
Increase/Decrease NOx	-22.3%	-88.9%	-90.3%

Table 21. Detailed Results for Natural Gas Engines for Baseload Applications

Baseload	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	310	316	320
Annual Cost @ Feeder ($/kW-year)	495	509	518
B/C @ Substation	.78	.85	.89
B/C @ Feeder	.51	.54	.57
Break-even Distribution Cost @ Substation ($/kW-year)	70	50	36
Break-even Distribution Cost @ Feeder ($/kW-year)	249	236	227
Increase/Decrease CO_2	-17.1%	-13.2%	-19.2%
Increase/Decrease NOx	-64.3%	-64.3%	-64.3%

Table 22. Detailed Results for Propane Fueled Engines for Baseload Applications

Baseload	2005	2010	2015
Annual Cost @ Substation ($/kW-year)	858	887	906
Annual Cost @ Feeder ($/kW-year)	858	887	906
B/C @ Substation	.28	.30	.32
B/C @ Feeder	.29	.31	.33
Break-even Distribution Cost @ Substation ($/kW-year)	618	620	621
Break-even Distribution Cost @ Feeder ($/kW-year)	612	614	615
Increase/Decrease CO_2	-17.1%	-13.2%	-19.2%
Increase/Decrease NOx	-64.3%	-64.3%	-64.3%

Section 5. Conclusions

Distributed generation is an emerging option for utilities. However, based on T&D system costs currently anticipated by NSTAR and provided for this study, as of this writing DG does not appear to be a cost-effective utility alternative. However, should conditions change, DG may indeed be a cost-effective option in some situations; specifically, if:

f) regional electricity supply prices increase significantly,

g) transmission congestion charges become a significant cost factor,

h) transmission or distribution upgrade costs are higher than costs assumed for this study (i.e., are similar to the national average), or

i) localized service reliability decreases.

j) a fixed charge rate lower than 0.15 can be used for DG (e.g., due to depreciation rules equivalent to those for transmission and distribution, and/or better familiarity with DG investments)

Utility Peaking Distributed Generators

Certainly, the first analytical task involved in evaluating the potential of DG for peaking applications from the utility perspective is to compare the cost of peaking DG to the near-term benefits, which include the estimated costs of transmission and distribution upgrade projects that are currently scheduled to be built.

In NSTAR's case, these transmission and distribution upgrades are either few or very low-cost. This is most likely because either the transmission and distribution system is robust and has a significant amount of unused capacity, or the scheduled upgrades are small or inexpensive projects, such as adding new tap changers or reconfiguring circuits and not the construction of extensive new facilities. The result of these extremely low T&D costs is unfavorable near-term economics for DG competing to serve peak load.

It would be a mistake, however, to end the analysis at that point. Unused capacity will be steadily consumed by load growth, and inexpensive T&D fixes will eventually be exhausted. Transmission and distribution upgrade projects in the future will almost certainly require more significant capital outlays than the costs assumed for this study. Therefore, it is appropriate to consider the use of DG under circumstances that are more typical of historical utility industry experience with T&D costs, and which could very likely occur.

Consider an example in which transmission access charges are assumed to be the same as the national average (12.1 $/kW-yr) as transmission capacity becomes tight, and distribution projects needed to serve new peak load cost an average of 30 $/kW-yr (a somewhat typical value for distribution upgrade costs).

In this alternative scenario, the economic prospects for DGs used in peaking applications at feeder locations would be improved, based on the benefit/cost ratios as shown in

Figure 15, and compared to those in Figure 12. In particular, both the advanced fuel cell and the microturbine are cost-effective in 2015 for this application.

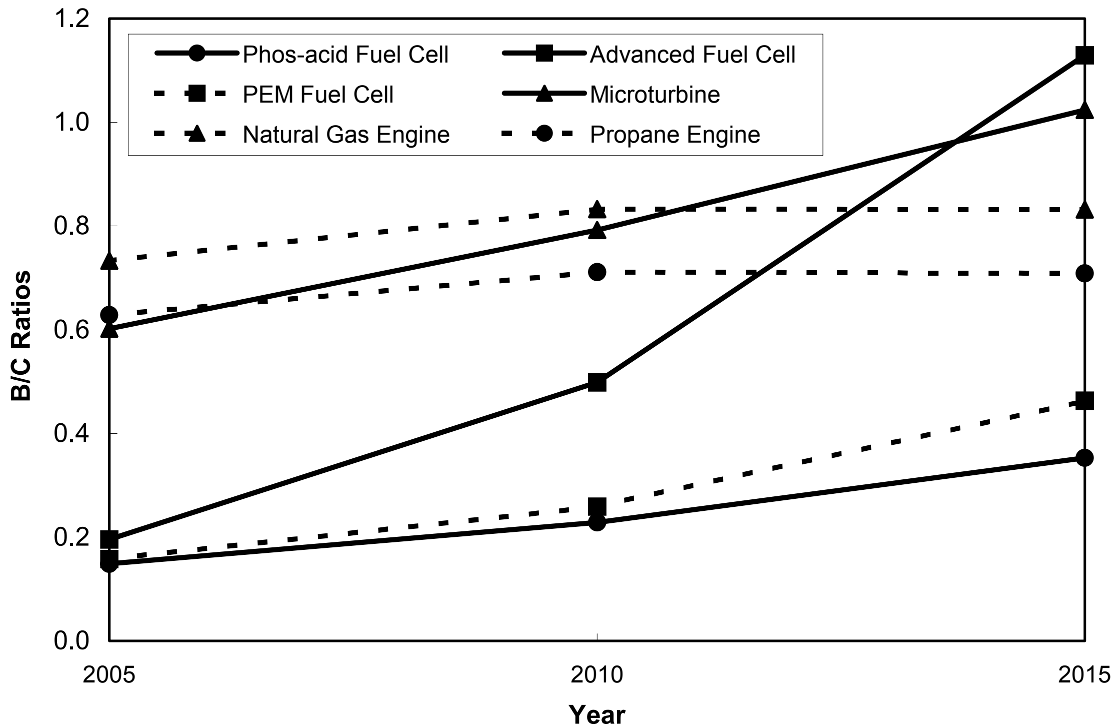

Figure 15. B/C Ratios, Peak Load Operation, at a Feeder Location, Assuming National Average T&D Costs

Utility Baseload Distributed Generators

Based on the results of the baseload analysis, the authors conclude that utility-owned DGs will have a difficult time competing with the grid for baseload/energy applications. Assuming that the values used for utility avoided cost are derived correctly, the only way that this will change is for DG technology cost (installed plant cost and variable maintenance cost) and performance (fuel efficiency) to improve, or for T&D avoided costs to increase.

When assuming the T&D cost values from the previous example – 30 $/kW-yr for distribution and 12.1 $/kW-yr for transmission – the prospects for DGs used for baseload duty cycle (as an energy resource) improve, as shown in Figure 16 (compare B/C ratios in Figure 16 to the B/C ratios shown in Figure 13).

Therefore, despite relatively low T&D upgrade costs reported by NSTAR in the immediate future, it is still important to evaluate DG as an important option for the longer term, when capacity may become tighter and T&D infrastructure will become more expensive.

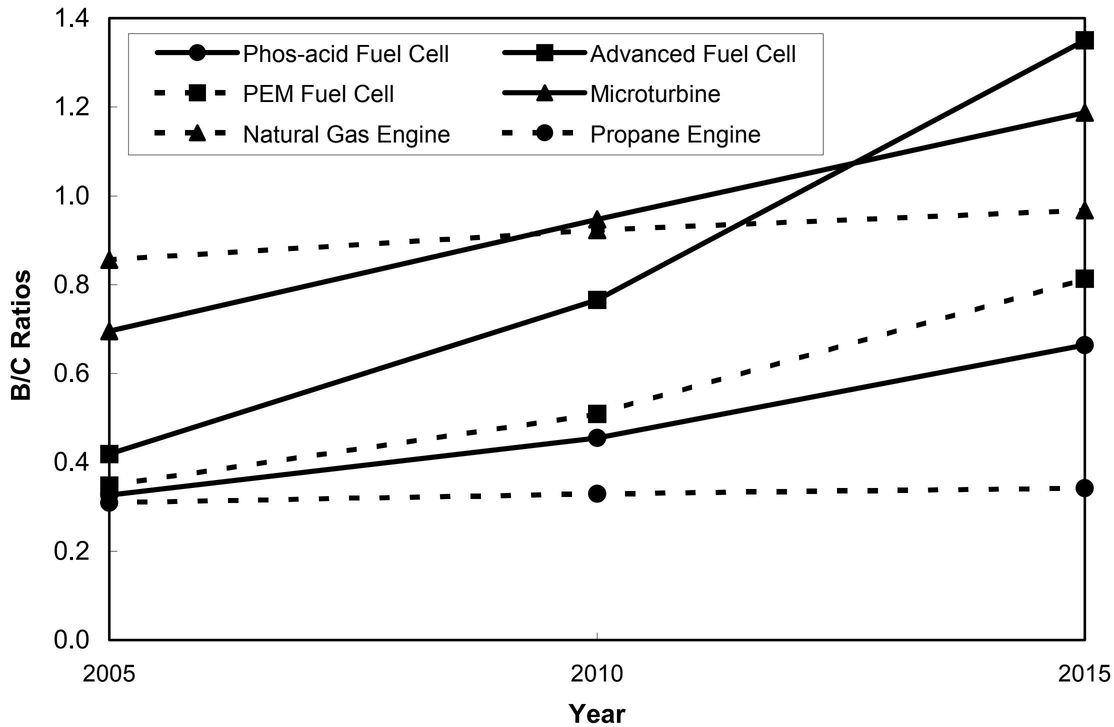

Figure 16. B/C Ratios, Baseload Operation, at a Substation, Assuming National Average T&D Costs

Comparing the Compact to National Average DG Benefits

When comparing DGs to the value mountains in Section 3 that reflect national average capacity and energy costs, the prospects for DGs appear improved over the previous results that used current NSTAR costs. This is especially true for baseload DGs at substations. Table 23 shows the total annual costs for the DGs used in this analysis. Figure 17 is the value mountain developed using annual average data for substation locations. As described in Section 3, the solid curve shows how much of the available market a DG is cost-effective for, based on its annual cost.

Table 23. Total Annual Cost, Baseload DGs, Substation Locations

($/kW-year)	2005	2010	2015
Phos-acid Fuel Cell	814	641	467
Advanced Fuel Cell	634	381	229
PEM Fuel Cell	764	573	381
Microturbine	382	308	261
Natural Gas Engine	310	316	320
Propane Engine	858	887	906

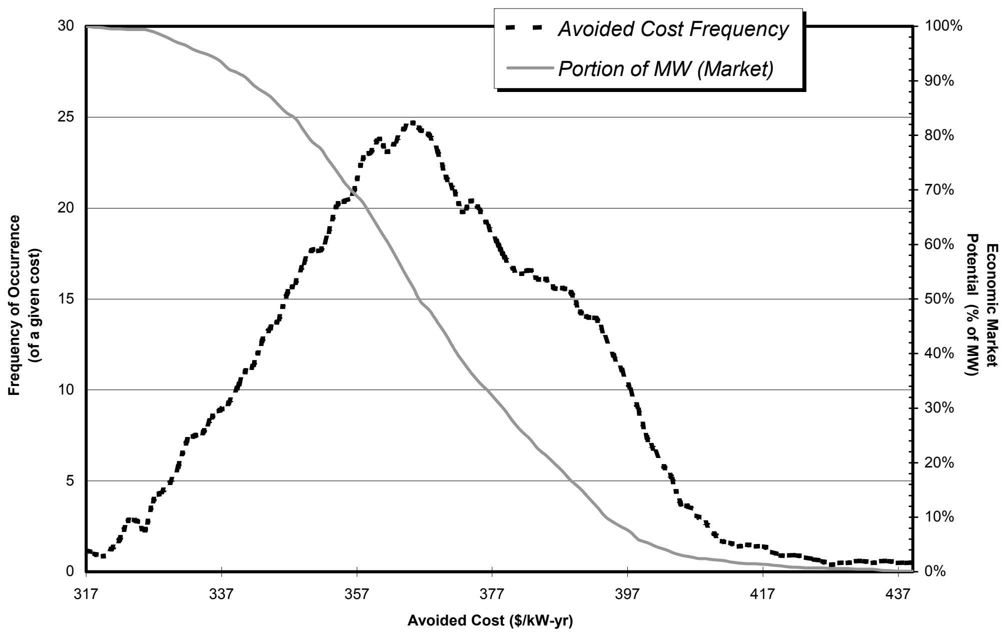

Figure 17. Value Mountains, Base Load, Substation Locations, Assuming National Average T&D Costs

As an example, consider the natural gas engine. From Table 23, the total cost to own and operate the DG in 2005 is 310 $/kW-yr; from Figure 17 it is seen that the natural gas engine is cost-effective for <u>all</u> the available market. Microturbines, at 382 $/kW-yr, are cost-effective for about 25% of the market. In 2010 the microturbine ($308 $/kW-yr) is now cost-effective for all market, and advanced fuel cells come down in cost to the point ($381 $/kW-yr) where they are competitive for about 25% of the market. In 2015 the advanced fuel cell is cost-effective for all of the market, and the PEM fuel cell at $381 $/kW-yr has 25% market share.

Readers are reminded that calculations at the substation are made assuming relatively low “city gate” (wholesale) natural gas prices, whereas fuel prices assumed for feeder locations are the retail gas prices paid by larger commercial and industrial end-users. If the price for gas is lower at feeder locations then many of those locations could also be served with cost-effective DG.

Propane fueled engines are not likely to compete as baseload resources, given the relatively high cost of propane fuel.

Emissions Impacts

In most cases DGs reduce the overall air emissions of CO_2 and NO_X, relative to the amounts that would otherwise be produced from energy from the grid. The primary reason for this is the fact that new generation in New England must meet NO_X emission limits of 1.5 lb/MWh, and in many cases they are not only much lower than this, but also lower than the NEPOOL average. This is especially true in 2015, when the economically superior advanced fuel cell, which has extremely low emissions, dominates the markets.

In this study, DGs were compared to the fleet average emissions for central power plants. If DGs are compared to a modern combined cycle plant whose efficiency exceeds 48% and whose NO_X emissions are less than five parts per million (0.16 lb/MWh), the result would be different (NEPOOL average marginal emission rate assumed for this study is 0.7 lb/MWh of NO_X [Ref. 4]).

This study did not address local emissions and air quality rules as they might affect the practicality of using DGs. As air emission and environmental regulations evolve, air emissions from DGs will become a key challenge. DGs seem destined to be more and more difficult to site and to permit, even if emissions are lower than those for the "avoided" central generation resource. Local concerns may be important factors, even if DGs contribute to regional benefits.

Recommendations

The DG option should be included in the planning process for transmission and distribution expansion. In particular, a process in which transmission and distribution loading conditions and cost estimates for likely system upgrades are evaluated systematically, identifying system "hot spots," would allow identification of high-value situations for which DG may be cost-effective.

Other distributed resource options, including distributed energy storage and geographically targeted energy efficiency and demand side management measures, could be considered as potential cost-effective alternatives to utility infrastructure projects. If these technologies are installed downstream from an overloaded or nearly overloaded distribution node, the benefits can be of the same magnitude as those associated with electric supply (e.g., reduced generation capacity needs and fuel use, T&D losses and air emissions).

Emerging energy storage technology (primarily batteries) may be an important cost-effective alternative to DG, especially if noise and/or air emissions are a key consideration.

Renting or leasing distributed generation or storage equipment may be a viable option. By renting, financial and operating risks are minimized and flexibility is maximized. If the DG is needed for only a few months per year (e.g., for June through September to serve the summer peak), then the annual cost may be lower than if the DG is owned. In fact, because a small amount of distributed resources (of any type) can defer transmission and/or distribution upgrades that are relatively large, such single-year deployments of distributed resources may be quite cost-effective.

Consider a simple example: a 9 MVA system is nearly overloaded. The load growth rate is 2.5%. The load growth for the next year is approximately 9 MVA * 2.5% = 225 kVA. The system distribution equipment will be upgraded to 12 MVA. The upgrade will cost

$30/kW-year, or $90,000 for one year (revenue requirements). If a distributed resource whose rating is 225 kVA or greater is installed downstream from where the upgrade is needed, then the cost avoided is 90,000 ÷ 225 kVA = $400/kW-yr of distributed resource capacity.

Note that this benefit from the distributed resource accrues for just one year of service. Benefits from and technical viability of using distributed resources in subsequent years must be evaluated annually.

Unique issues shape prospects for DG on Martha's Vineyard. Martha's Vineyard is supplied by an underwater transmission cable and is served by a radial supply system with no alternate supply lines. In this study, Martha's Vineyard was treated in same manner as the Cape; however, additional analysis would be possible if refined information concerning Martha's Vineyard is available. No natural gas is available on Martha's Vineyard; however, liquefied natural gas (LNG) could be investigated as an option, especially for peaking applications that don't require large amounts of fuel storage.

Appendix A: DG Technology Cost & Performance Data

Fuel Cells

Year	Tech-nology ID	Size Range kW	Capital Cost $/kW	Installed Cost $/kW	Co-gen? Y/N	Heat Rate (HHV) Btu/kWh	Variable O&M $/kWh	Fixed O&M $/kW-yr	NO_X Emissions ppm	NO_X Emissions lb/MWh	CO_2 Emissions lb/Mwh	Model / Type
2005	FC-1A	200	3000	4250	N	8,420	0.01	10.0	0.9	0.033	850	ONSI PC-25 / Phos-Acid
	FC-1B	200	3500	5000	Y	8,420	0.01	10.0	0.9	0.033	850	ONSI PC-25 / Phos-Acid
	FC-2A	250	3000	4000	N	7,575	0.01	10.0	1.0	0.033	950	Ballard / PEM
	FC-3A	250	2800	3200	N	6,890	0.01	10.0	1.8	0.055	950	FCEL / MCFC
2010	FC-1C	200	2250	3125	N	8,000	0.01	7.5	0.9	0.031	808	ONSI PC-25 / Phos-Acid
	FC-1D	200	2625	3750	Y	8,000	0.01	7.5	0.9	0.031	808	ONSI PC-25 / Phos-Acid
	FC-2B	250	2000	2750	N	7,230	0.01	7.5	1.0	0.031	907	Ballard / PEM
	FC-3B	250	2150	2500	N	6,770	0.01	7.5	1.8	0.054	933	FCEL / MCFC
	FC-4A	100	1000	1350	N	8,420	0.01	7.5	1.5	0.055	950	Siemens / SOFC
	FC-4B	100	1350	1900	Y	8,420	0.01	7.5	1.5	0.055	950	Siemens / SOFC
2015	FC-1E	300	1500	2000	N	7,575	0.01	5.0	0.9	0.030	765	ONSI PC-25 / Phos-Acid
	FC-1F	300	1750	2500	Y	7,575	0.01	5.0	0.9	0.030	765	ONSI PC-25 / Phos-Acid
	FC-2C	250	1000	1500	N	6,890	0.01	5.0	1.0	0.030	864	Ballard / PEM
	FC-3C	1,000	1500	1800	N	6,650	0.01	5.0	1.8	0.053	917	FCEL / MCFC
	FC-4C	500	400	550	N	6,315	0.01	5.0	1.5	0.041	713	Siemens / SOFC
	FC-4D	500	650	1000	Y	6,315	0.01	5.0	1.5	0.041	713	Siemens / SOFC

Notes:

1) Capital costs represent production units, not early production or prototypes.

2) Installed costs are all-inclusive (excluding finance costs): labor, materials, engineering, permitting, overhead, metering and instrumentation, etc.

3) Natural gas fuel is assumed, unless otherwise specified. All fuel cells should be operable on landfill gas and oilfield gas, with a small additional capital cost for fuel filtering/processing. Due to limited experience in the field, no definite numbers are available for these additional costs, but they should be small (~5% or less) in relation to total installed cost. The landfill gas and oilfield gas applications include these costs.

4) Variable O&M costs primarily represent fuel cell stack replacement costs.

5) Fixed O&M costs represent labor and materials for routine maintenance.

6) All fuel cells include reformers for producing hydrogen from natural gas. Cost, heat rate and NO_X data include reformer data as applicable.

7) Costs are given in constant 2003 dollars.

Microturbines

Year	Tech-nology ID	Size Range kW	Capital Cost $/kW	Installed Cost $/kW	Co-gen? Y/N	Heat Rate (HHV) Btu/kWh	Variable O&M $/kWh	NOx Emissions ppm	NOx Emissions lb/MWh	CO_2 Emissions lb/MWh	Model/Type	NOx Reduction Method(s)
2005	M-1A	60	817	940	N	13,540	0.010	9.1	0.544	1188	Capstone C60	Lean-premix combustion
	M-1B	60	950	1093	Y	13,540	0.010	9.1	0.544	1188	Capstone C60	Lean-premix combustion
	M-2A	30	1057	1290	N	13,985	0.010	9.0	0.558	1227	Capstone C30 HP[1]	Lean-premix combustion
	M-2B	30	1323	1575	Y	13,985	0.010	9.0	0.558	1227	Capstone C30 HP[1]	Lean-premix combustion
	M-3A	28	1295	1540	N	15,205	0.010	9.1	0.611	1334	Capstone C30 LP	Lean-premix combustion
	M-3B	28	1550	1845	Y	15,205	0.010	9.1	0.611	1334	Capstone C30 LP	Lean-premix combustion
	M-4A	30	1110	1345	N	14,540	0.010	9.1	0.584	1276	Capstone C30 Biogas	Lean-premix combustion
	M-4B	30	1375	1610	Y	14,540	0.010	9.1	0.584	1276	Capstone C30 Biogas[2]	Lean-premix combustion
	M-5A	30	980	1162	N	13,985	0.010	9.0	0.558	1227	Capstone C30 OFG[3]	Lean-premix combustion
	M-5B	30	1010	1202	Y	13,985	0.010	9.0	0.558	1227	Capstone C30 OFG[3]	Lean-premix combustion
	M-6A	29	1395	1635	N	15,205	0.010	31.3	2.110	1334	Capstone C30 LF[4]	Lean-premix combustion
	M-6B	29	1670	1910	Y	15,205	0.010	31.3	2.110	1334	Capstone C30 LF[4]	Lean-premix combustion
2010	M-1C	60	700	825	N	10,820	0.0047	1.6	0.078	950	Capstone C60	DOE research target
	M-1D	60	825	945	Y	10,820	0.0047	1.6	0.078	950	Capstone C60	DOE research target
2015	M-1E	60	500	625	N	9,435	0.0047	1.9	0.078	828	Capstone C60	DOE research target
	M-1F	60	625	715	Y	9,435	0.0047	1.9	0.078	828	Capstone C60	DOE research target

[1] Using propane fuel.
[2] CHP probably not available at most landfill sites; costs provided for reference, if CHP is feasible, and include the extra equipment needed for processing the landfill gas.
[3] Provided without standard casing and packaging; assumed to be installed in industrial environment.
[4] Using diesel fuel.

Notes:
1) Capital costs represent production units, not early production or prototypes.
2) Installed costs are all-inclusive (excluding finance costs): labor, materials, engineering, permitting, overhead, etc.
3) Natural gas fuel is assumed, unless otherwise specified.
4) Costs are given in constant 2003 dollars.
5) All combustion turbine data for 2005 are assumed to be valid in subsequent years.

Natural Gas and Propane Engines

Tech-nology ID	Size Range kW	Capital Cost $/kW	Installed Cost $/kW	Co-gen? Y/N	Heat Rate (HHV) Btu/kWh	Variable O&M $/kWh	NOx Emissions g/hp-hr	NOx Emissions lb/MWh	CO_2 Emissions lb/MWh	Model/Type	NOx Reduction Method(s)
NG-1A	200-1000	500	700	N	11,500	0.010	5.00	14.78	970	Caterpillar 14-69L	Factory air/fuel ratio system
NG-1B	800-1000	500	700	N	11,500	0.010	0.54	1.60	970	Caterpillar 34-69L (LFG)	Factory lean burn technology
NG-2A	500-1000	675	1050	N	11,500	0.014	0.20	0.59	970	Caterpillar 34-69L	SCR
NG-2B	500-1000	675	1050	N	11,500	0.014	0.20	0.59	970	Caterpillar 34-69L (OFG)	SCR
NG-2C	500-1000	750	1100	N	11,500	0.014	0.10	0.30	970	Caterpillar 34-69L	SCR
NG-3	50-750	300	430	N	13,000	0.0092	0.84	2.49	1097	Cummins	Single catalyst
NG-4A	330-1750	400	550	N	9,970	0.0092	0.80	2.37	841	Cummins QSK/QSV	Lean burn
NG-4B	330-1750	550	670	Y	9,970	0.0097	0.80	2.37	841	Cummins QSK/QSV	Lean burn
NG-4C	330-1750	600	780	N	9,970	0.0110	0.08	0.25	841	Cummins QSK/QSV	90% open-loop SCR + oxidation catalyst
NG-4D	330-1750	750	870	Y	9,970	0.0115	0.08	0.25	841	Cummins QSK/QSV	90% open-loop SCR + oxidation catalyst
NG-4E	330-1750	450	610	N	9,970	0.0110	0.50	1.48	841	Cummins QSK/QSV (LFG)	Lean burn; or rich burn + catalyst
NG-4F	330-1750	600	720	Y	9,970	0.0115	0.50	1.48	841	Cummins QSK/QSV (LFG)*	Lean burn; or rich burn + catalyst
NG-4G	330-1750	400	550	N	9,970	0.0092	0.80	2.37	841	Cummins QSK/QSV (OFG)	Lean burn
NG-4H	330-1750	550	670	Y	9,970	0.0097	0.80	2.37	841	Cummins QSK/QSV (OFG)	Lean burn

* CHP probably not available at most landfill sites; costs provided for reference, if CHP is feasible, and include the extra equipment needed for processing the landfill gas.

Notes:
1) Capital costs represent production units, not early production or prototypes.
2) Installed costs are all-inclusive (excluding finance costs): labor, materials, engineering, permitting, overhead, etc.
3) Propane gas fuel is assumed, unless otherwise specified.
4) Costs are given in constant 2003 dollars.
5) Natural gas engine data are valid for all years.

References

1. Conference call with NSTAR staff (Dave Dishaw, Charlie Salomone, et. al.) and project manager Scott Ridley, December 23, 2002; followed by written communication dated January 13, 2003, from J. David Dishaw to Scott Ridley, containing, among other data, NSTAR's anticipated capital expenditures for transmission and distribution, and forecast peak load growth. Annualized costs for transmission and distribution upgrades were derived by DUA by dividing the anticipated capital expenditures by the MW of peak load growth and multiplying by the utility fixed charge rate of 0.13 assumed for this study.

2. Pupp, Roger; Woo, C.-K.: *Costs of Service Disruptions to Electricity Customers,* The Analysis Group, Inc., January 1991.

3. *Economic Market Potential for Utility-Owned Distributed Generation*, Edison Electric Institute, October 2001, p. vii.

4. Ozone Transport Commission, *The OTC Emissions reduction Workbook 2.1: Description and User's Manual,* prepared by Synapse Energy Economics, Table 2.4: Emission Rates from New England Power Plants, December 2002.