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Valuation of Renewable and Distributed Resources: Implications for the Integrated Resource Planning Process

1013037

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1013037

Technical Update, June 2007

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CITATIONS

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This document describes research sponsored by the Electric Power Research Institute (EPRI) and Hawaiian Electric Company.

This publication is a corporate document that should be cited in the literature in the following manner:

Valuation of Renewable and Distributed Resources: Implications for the Integrated Resource Planning. EPRI, Palo Alto, CA, Hawaiian Electric Company, Inc., Honolulu, HI, Rocky Mountain Institute, Snowmass, CO, Henry Luce Foundation, New York, NY, and Hewlett Foundation, Menlo Park, CA: 2007. 1013037.

ABSTRACT

Over the last two decades, traditional integrated resource planning (IRP) has proven to be a valuable tool for evaluating the tradeoffs between supply-side generation and demand-side efficiency resources. However, there has been increasing focus on the incorporation of renewable, distributed, and demand-side resources into utility planning, which requires new methodologies to assess the value of these resources. Traditional IRP is generation-centric and typically fails to take into account the operational performance and costs and benefits of the distribution system. Traditional IRP takes a narrow view of reliability as loss of load probabilities and can neglect the more subtle issues of power quality. Traditional IRP rarely quantifies the risk tradeoffs between fossil and renewable resources.

In support of the integrated resource plans of Hawaiian Electric Company (HECO) and its subsidiary companies Maui Electric Company (MECO) and Hawaii Electric Light Company (HELCO), EPRI with leadership from Rocky Mountain Institute (RMI) conducted a series of workshops. These workshops provided information to HECO staff on RMI's methodologies to integrate risk/benefit analysis of energy resources into the integrated resource planning process. HECO seeks practical methods for their IRP practitioners to integrate these issues into current and future IRP processes. RMI has codified its insights into incorporating renewable, distributed, and demand-side resources into the integrated planning process with its Energy Resource Investment Strategy (ERIS) methodology. This report documents the details of the workshops presented to the HECO utilities.

ACKNOWLEDGEMENTS

EPRI and The HECO utilities would like to sincerely thank Rocky Mountain Institute for sharing and making available their views on this matter. In addition, thank you to the Henry Luce Foundation and the Hewlett Foundation for their contributions.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
PREFACE

The evaluation of renewable energy and distributed generation resources within integrated resource planning (IRP) requires the consideration of many factors and poses an analytical challenge to the electric utility. This is even more difficult on small isolated island electric systems.

For example, capacity value for intermittent resources such as wind and photovoltaic has been raised in resource planning since assigning capacity value to intermittent resources may improve their overall cost-effectiveness. Capacity payments for an intermittent resource were debated before the Hawaii Public Utilities Commission in Docket No. 00-0135 (Apollo Energy Corporation). In Decision & Order No. 18568, dated May 30, 2001, the Commission stated that capacity payments for the Apollo (windfarm) were not warranted. The Commission found that Hawaii Electric Light Company (HELCO) would not be able to avoid or defer construction of firm generating units, and that Apollo was not under a continual obligation to supply power to HELCO upon demand.

Under certain circumstances, intermittent resources may improve system reliability. On the other hand, intermittent resources generally do not allow the utility to defer or avoid firm capacity additions, and do not allow the utility to build less firm capacity. As-available energy suppliers do not have an obligation to deliver power in the amount needed and at the time needed.

Some have advocated the concept of Effective Load Carrying Capability (ELCC). A resource's ELCC value would be based on the probability of the as-available resource being available to serve load during the critical load periods. ELCC is a probabilistic measure of the "equivalent capacity" or "effective" amount of load carrying capability that is added to a generating system when one or more generating units is added. ELCC is determined through a probabilistic analysis of the relationship between a generating system's load and the Loss of Load Probability (LOLP).

LOLP is a probabilistic measure of the risk that the demand on a generating system will not be met due to random and sometimes multiple outages of generating units on the system. LOLP is dependent upon the number of available generating units within the generating system, the size and forced outage rates of each generating unit, and the demand on the generating system.

Hawaiian Electric Company (HECO) acknowledges that the ELCC methodology will produce a non-zero ELCC for intermittent as-available resources. However, an increase in reliability is not the same as having firm capacity. There are many significant differences between firm capacity and an increase in reliability (which can be equated to an ELCC for intermittent as-available resources).

The HECO utilities cannot be expected to meet a portion of their obligation to provide firm power to customers based on receiving highly variable output from an intermittent resource. While the ELCC method may appear to produce an equivalent firm capacity, the fact is that the output from intermittent resources is highly variable and capacity cannot necessarily be provided by the as-available resource in the amount required and at the time required by customers of the HECO utilities.

With regards to distributed generation resources, the nature of distributed generation makes it difficult to analyze in an IRP process. The IRP process analyzes resources at the system level prior to the identification of specific projects. In addition, an individual distributed generation project is generally too small to impact the timing of central station units or transmission line timing. For these reasons, distributed generation must be considered on a generic basis without consideration of site-specific project impacts. In order to complete a fair evaluation, an aggregate forecast of distributed generation resources must be developed for use in the IRP analyses.

The methods used to evaluate renewable energy and distributed generation resources in the electric utility industry are constantly evolving. HECO and its subsidiaries Hawaii Electric Light Company and Maui Electric Company seek to better understand alternative methods for evaluating such resources through the series of workshops with leadership from Rocky Mountain Institute as documented in this report. The methodologies and conclusions presented in this report are strictly that of Rocky Mountain Institute.

2
INTRODUCTION

As we enter the 21st century, renewable and distributed power resources are destined to provide an ever-increasing share of the electricity supply. These resources are profoundly different from the centralized nuclear and fossil-fuel-fired units that have dominated the last eighty years of electric generation. Taken together, these technologies can provide electric power services with higher quality and reliability, at lower cost, and with less environmental impact than conventional generation resources. In short, they represent a suite of disruptive technologies that will ultimately revolutionize the industry.

This revolution is not in the distant future. It has already arrived. Competition in power generation has begun to impose greater market discipline, such that utilities can no longer build hugely expensive nuclear and coal-fired plants with full confidence of recovering capital costs. Central steam-turbine generation plants stopped getting more efficient in the 1960s, stopped getting cheaper in the 1970s, stopped getting bigger in the 1980s, and stopped getting built in the 1990s. Worldwide, by the end of 2004, distributed generation and renewable energy had more installed capacity than nuclear power, the other major competitor to centralized fossil-fuel generation. In 2004, decentralized cogeneration and renewable power added 6.6 times as much worldwide net capacity, and 5.6 times as much annual electricity production, as nuclear power added. By the end of 2004, these competitors' global installed capacity totaled roughly 411 GW —12 percent more capacity than global nuclear plants' 366 GW —and produced roughly 94 percent as much electricity. The projected growth rates for renewable and distributed power far exceed nuclear power (see Figure 2-1).

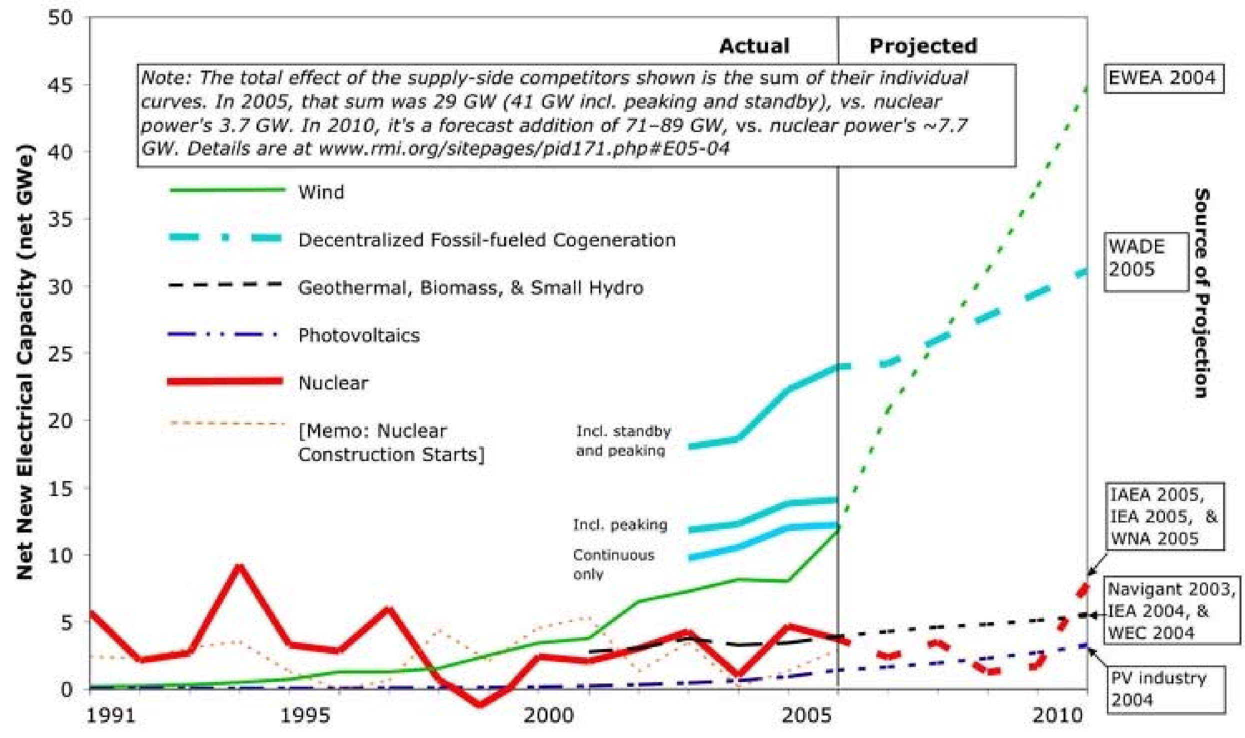

Figure 2-1
Global Additiona of Electrical Generating by Year and Technology: 1990–2005 Actual and 2006–2010 Projected[1]

The utility industry is beginning to seriously consider these alternatives and work is needed to understand how to correctly value both their costs and benefits as penetration increases. The valuation task is more challenging than most utility planners realize for several reasons:

- Risk mitigation benefits must be quantitatively valued. Risk mitigation includes not only fossil-fuel risk, but also reliability risk and the risk of over (or under) estimating demand growth. Techniques for quantitatively evaluating risk mitigation can be found in financial theory, and must now be applied to the planning of electric power systems;
- Grid-side benefits and costs should be explicitly considered within an integrated resource planning process (IRP). The grid-side benefits from distributed resources include deferral of distribution (and sometimes transmission) capacity additions as well as operational benefits from placing power generation closer to the loads they serve. Conversely, intermittent renewable power often imposes operational costs at each time scale (regulation, load-following, and unit commitment) and can require new transmission lines to move the power from remote locations;

[1] Rocky Mountain Institute. (2006). *The Rise of Micropower*. Accessible at www.rmi.org/sitepages/pid171.php#E05-04

- The reliability benefit of intermittent renewable resources must be explicitly recognized as the amount of conventional generation capacity that can be displaced due to the addition of a particular portfolio of renewable assets. For a particular reliability level (loss-of-load probability, or LOLP), the additional load that can be served by a set of generation assets is the effective load-carrying capability (ELCC). This metric serves as the starting point for understanding capacity displacement;

- The portfolio benefits of combinations of renewable and distributed resources need to be defined, rather than being evaluated as independent individual units, due to the potential covariance between these resources. The combination of renewable and distributed resources often creates synergies that are unseen if each is looked at in isolation;

- Customer-side benefits, particularly the avoidance of business interruption from increased reliability, must be recognized; and

- Benefits and costs are dynamic, not static. They change with penetration rate, and there are often diminishing returns to the addition of increasing amounts of intermittent renewable resources.

The implications of correctly valuing these resources are profound. The incorporation of the appropriate capacity credit for intermittent renewable resources will often provide the economic justification for building additional wind resources. Conversely, failure to incorporate the appropriate capacity credit for intermittent renewable resources may mean that we are overbuilding generation capacity at a rate of roughly 10–20 percent the amount of renewable resources on the system. How big a problem is that? Consider that the renewable power industry has been adding about 13 gigawatts (GW) of capacity every year. In 2004, global capacity additions were 8 GW of wind, 4 GW of geothermal/small hydro/biomass/wastes, and 1 GW of photovoltaic, but the intermittent resources—wind and photovoltaic power—did not typically receive capacity credit. Thus, in 2004 alone, the global electric utility industry potentially overbuilt 1.8 GW. Wind capacity is expected to triple in the next four years, likely increasing the magnitude of the problem. Most new wind development is in Europe, which aims to get 22 percent of its electricity from renewable power by 2010 and has taken the lead on defining methodologies for evaluating the benefits and costs of intermittent renewables.

When correctly valued, distributed resources are often two to three times *less* expensive than large-scale centralized resources, even if the busbar costs are similar. In Rocky Mountain Institute's book *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size* (2002), we presented the first comprehensive analysis of how making electrical resources the right size can minimize their costs and risks and capture unexpected sources of profit and advantage. The book outlined 207 ways in which making electrical resources (generators, storage, or efficiency) the right size for their task can boost their economic value, typically by about three to five fold, though the exact value is site- and technology-sensitive.

The increase is due to three factors that will be discussed further in this paper:

- **Financial economics**: modern tools for financial risk management reveal a significant gain in value for renewable sources as fossil fuel prices and supply volatility increase. For all modular resources, properly counting the reduced financial risks of small, fast, portable resources versus central generation plants increases value as demand uncertainty increases. Collectively, the risk management benefits can increase the value of distributed generation by two- to three-fold;

- **Electrical engineering**: lower grid costs, smaller line losses, longer equipment life, and more graceful handling of failures can increase the value of a distributed resource by two- to three-fold—even more if the decentralized generating project is located in an area with a congested grid or if the customer requires high power-quality or reliability; and

- **Customer-side benefits**: dozens of other benefits may combine to increase the value of distributed generation resources, typically by about two-fold—more if heat produced as a byproduct of electricity generation is recaptured for industrial processes or space heating.

In interconnected utility systems in the United States, many of the operational costs and benefits discussed above can be evaluated based on the prevailing power markets in a particular region. For example, ISO-New England and the Pennsylvania-Jersey-Maryland Interconnection (PJM) explicitly value capacity and several ancillary services. Thus, the analytic task is to correctly understand the impacts of intermittent generation, then use the market to evaluate the economic benefits or costs, and finally to apply financial theory to correctly account for risk or uncertainty.

This is not the case for geographically-isolated power systems that are not interconnected, including the utilities within the Hawaiian Electric Industries (HEI) system.[2] In these systems, theoretical benefits or costs of renewable or distributed resources are not continuous functions. In isolated systems, there must be physical assets, either on the supply or demand side, that are collectively capable of providing the necessary power-services reliability. Thus, if intermittent renewable resources impose operational costs on a particular time scale, there must be a physical asset dedicated to managing the combined variations of supply and demand. Further, even though the correlation between an intermittent renewable resource and peak load means that system reliability is improved, the net benefit in terms of capacity credit must be defined by the set of renewable and other assets (such as storage or demand response) required to displace conventional power generation capacity.

This report explores the underlying theory and practical methodologies for the valuation of renewable and distributed resources. The theoretical basis is presented first to acquaint the reader with the underlying rationale for the approach to valuing these resources. We then present the practical methodologies that can be used to estimate these benefits on real utility systems. In several cases, spreadsheet-based tools have been developed that can be used to apply these methodologies. Where there are differences between interconnected systems and isolated systems, potential adjustments are discussed.

[2] The HEI system includes the Hawaiian Electric Company (HECO), the Maui Electric Company (MECO), and the Hawaiian Electric Light Company (HELCO).

Finally, an overview is provided regarding how these techniques can be incorporated into the integrated resource planning process (IRP). Much of this work is drawn from Rocky Mountain Institute's publication *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size* (2002), and from research across the United States and Europe.

3
FUNDAMENTALS OF RENEWABLE RELIABILITY

One of the primary goals of utilities is maintaining the reliability of the electric system. One implication of this goal is the notion that the reliability of any individual generator is only important in the larger context of system reliability. This insight also recognizes that all generators, both conventional and intermittent, have some probability of failure. That probability of failure is, of course, due to different causes. The forced outages of conventional generators result from unplanned mechanical failures, whereas the effective "forced outages" of intermittent generators are due to the risk of "fuel" (i.e., wind or sun) availability. These two factors lead to the conclusion that, when evaluating the reliability of intermittent renewable generators, we must evaluate them for the contribution they make to overall system reliability rather than the reliability of an individual renewable generator.

To properly understand the value of intermittent generators in terms of system reliability, though, it is critical to return to first principles and understand how intermittent generators can contribute to system reliability. This knowledge is, in turn, based on an understanding of how both system demand and renewable power output are impacted by the weather. In some systems, load and renewable output are frequently driven by the same underlying cause. For example, in many warm regions where cooling loads peak in the early afternoon, a solar generator's output is generally at its highest level. Thus, if load and intermittent output peak at the same times, the intermittent generator likely contributes substantially to system reliability.

With this fundamental understanding in hand, the next step is to analyze the statistical properties of the intermittent resource that define its availability during the utility's peak period. Often, the intermittent resource's capacity factor during peak periods is used as an approximation of reliability contribution. However, more sophisticated techniques exist and are discussed next.

First, one of the key insights that can be gleaned from these basic statistical analyses is the extent of covariation between existing or potential renewable generators. Like modern financial portfolio theory, considering renewable generators together as a portfolio should have the effect of reducing the overall portfolio variability. Portfolio variability is less than the simple sum of individual generator variabilities due to either geographical dispersion of generators or the varying output patterns of different types of renewables.

Once a combined renewables portfolio output has been determined, this output stream can be incorporated into existing utility production-cost and reliability models that then evaluate the *net increase* in total variability (of load plus renewables) due to the addition of renewable generators. This process also determines the amount of conventional capacity that can be deferred or displaced due to the addition of renewable generators. This amount of capacity is the effective load carrying capability (ELCC), or capacity credit, of the renewable generators. The ELCC methodology is well established both in the United States and Europe, where results indicate both a decreasing capacity credit and increasing cost of balancing energy as renewable penetration increases.

Thus far, we have discussed the methodology for determining the benefits of renewable generators. No analysis is complete, though, without determining both the benefits and costs. Thus, it is critical to define the operational costs of renewable integration, including additional reserves needed in each time scale, as well as the cost impacts to conventional resources due to increased demand for ramping.[3] These costs are non-zero but, in studies conducted around the country, they are generally found to be low.[4] Especially critical to isolated systems such as those found on islands is the potential to "firm" intermittent generation through storage or demand response. Creating a portfolio of intermittent generators and firming technologies can allow for a direct cost comparison to conventional resources, thereby highlighting the hedging value of renewable resources against fossil-fuel price volatility. The following sections and chapters delve into these insights in more detail.

Meteorological Drivers of Load and Generation

The process of assessing renewable reliability contributions begins with first principles by understanding how both system demand and renewable output are impacted by the weather. The first step is to identify what meteorological conditions cause peak power demand in the electric utility's service territory. The second consideration is whether underlying drivers of power output for particular renewable resources are correlated to the meteorological conditions that affect load. If so, what are the meteorological cycles that affect these relationships (i.e., daily, seasonal, etc.)? Lastly, the relevant wind regimes at the specific sites serving the system and how they interact within a portfolio must be identified.

The correlation between weather and power demand is especially evident when we examine power demand according to end use. In many systems, peak load is directly linked to weather patterns through heating, ventilation, and air conditioning (HVAC) load, which is driven primarily by temperature and humidity (see California utility system example in Figure 3-1).

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[3] Some operational costs are likely difficult to estimate, for example, residual system frequency deviations and increased risk of load shedding.
[4] For systems with small spinning reserves, the cost may be higher due to the potential need to add ramping capability.

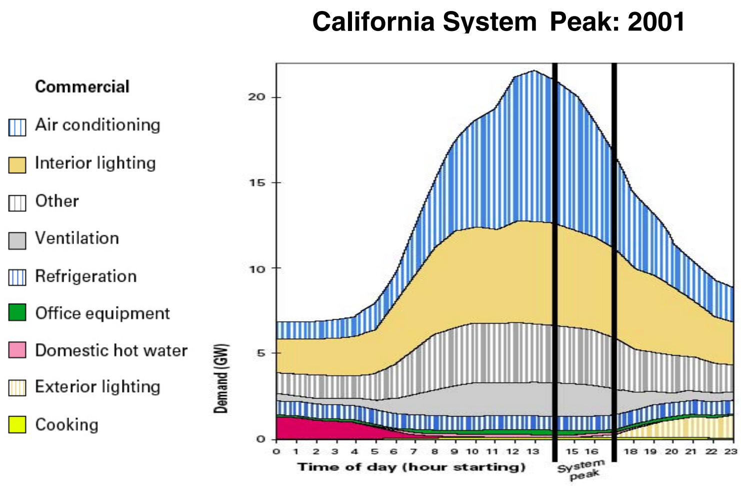

Figure 3-1
End-Use Structure of 2001 California Summer Peak-Day Loadshape for the Commerical Sector[5]

Hawaii also provides an excellent example of the relationship between peak load and weather patterns. There, new development and a growing afternoon HVAC demand has the potential to change the timing of the peak load. Historically the peak occurred in the evening, when demand for residential water heating was highest. As air conditioning penetration grows and load-management programs become effective, the weather-dependent air conditioning load fraction will be increasingly important in defining the peak.

Intermittent renewable generators are, by definition, driven by the weather. The question is simply whether the weather patterns driving renewable resources are the same patterns driving load. Tidal and solar resources are perhaps most obviously correlated to distinct weather patterns. The tides are driven by the most reliable weather pattern known, and the fluctuations in the tides can be predicted well into the future. Insolation is also driven by a well-known and regular weather pattern—the sun. Insolation is only less reliable than tidal action because of interference from clouds. Because solar-power production is driven by the sun, which also typically drives temperature, and thus load, in many systems, there is reason to believe in a significant correlation between solar output and load. This concept is depicted in Figure 3-2, which shows the general correlation between solar output and load in the California system.

[5] Brown, R. and Koomey, J. (2002) Electricity Use in California: Past Trends and Present Usage Patterns. *Energy Policy.* LBL-47992.

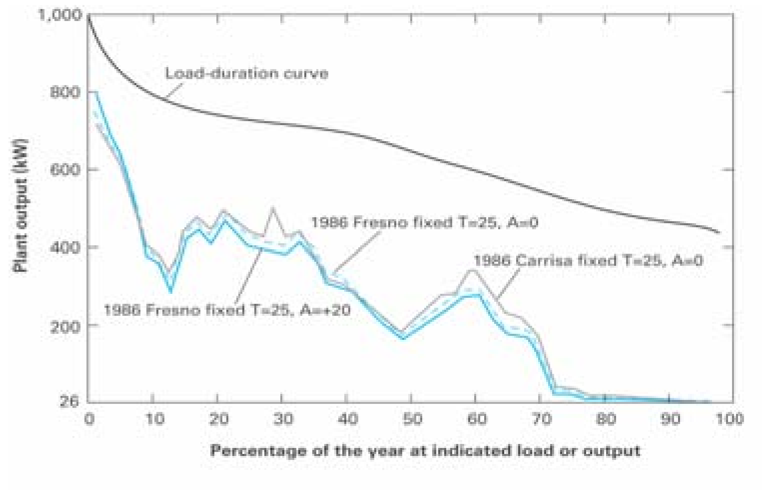

Figure 3-2
Photovoltaics Well Match PG&E's Annual Load-Duration Curve[6]

While this idea of weather-driven peak coincidence is relatively easy to determine for renewables such as tidal, solar, and even hydropower, wind is significantly more complicated. There are three primary wind regimes that affect Hawaii, and indeed, most systems: trade, convection, and frontal. Trade winds are seasonal and highly reliable, but they are primarily driven by pressure, not temperature (which, as discussed above, is a significant driver of power demand in many systems). However, since the trades are very reliable, wind power from the trades has the potential to contribute to system reliability. Convection winds follow a daily cycle based on land and sea temperature differentials. This combination of daily trends and temperature relations means there is a significant possibility of coincidence with daily patterns in power demand. Finally, frontal winds are driven by storms and are therefore erratic and unlikely to be able to support reliable wind output in most places.

A major consideration—besides whether the wind will be there—is, on a macro scale, whether it will be there when it is needed. Thus the goal becomes identifying sites with good wind speeds that are temporally coincident with peak power demand, such as the one shown in Figure 3-3.

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[6] Shugar, D. *et al.* (1992). *Benefits of Distributed Generation in PG&E's Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation*. Pacific Gas & Electric.

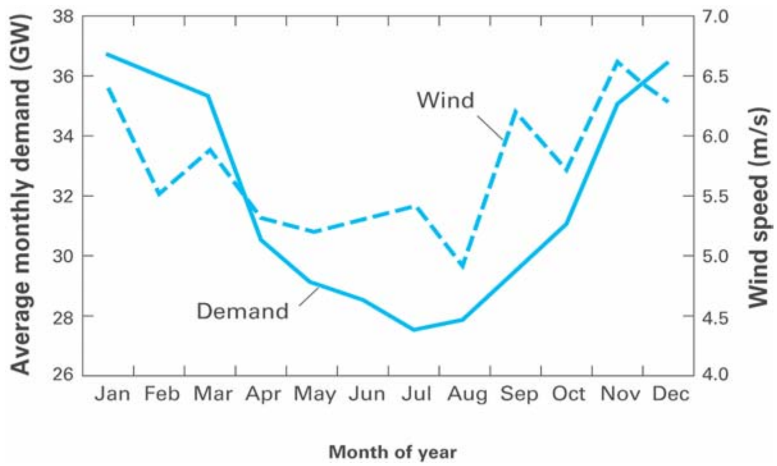

Figure 3-3
Correlation of Wind and Electricity Demand in England[7]

Algorithm for Evaluating Contribution to Reliability

After obtaining a rough approximation of the relationships between the weather, intermittent generation and power demand, we introduce several statistical methods to be used as screening tools when evaluating the correlation and peak coincidence of renewable output and load. Oftentimes, aggregating renewable resources into a portfolio for analysis results in a reduction in the portfolio variability due to negative covariance or geographic dispersion of resources. These analyses are discussed in the next chapter.

In this process it is important to define the total variation of the system, incorporating both load and renewable variability. It is the *net* increase in system variability due to the addition of renewable generators that matters. This net variability is captured by incorporating the output of a portfolio of renewable generators into a utility's production-cost or reliability model, as is discussed in Chapter 4. For planning purposes, it is valuable to determine the equivalent capacity benefit of a renewable generator. The expected locations of renewable resources can be used in dispatch models to evaluate unit commitment, and in transmission models to determine grid implications.

The integration of renewable generators necessitates reserves at each time scale (seconds, minutes, and hours) and may also incur costs on conventional plants due to potential increases in demand for ramping capability. It is also necessary to factor in the costs of storage or demand response to firm intermittent renewables, thereby allowing for a direct calculation of the net benefit of renewables as a hedge against volatile fossil fuel prices. These methods are discussed in Chapter 5.

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[7] Thresher, R. (1996). *Wind as a Distributed Resource*. Electric Power Research Institute 2nd DR Conference.

Results from U.S. and European Studies

Studies from both the United States and Europe support of the conclusion that renewables have non-zero capacity benefits to a power system. As an example of the value of weather-driven peak coincidence, California's 2004 *RPS (Renewable Portfolio Standard) Integration Study*[8] found solar provided a significant reliability contribution in the form of an expected load carrying capacity (ELCC) greater than 80 percent (see Figure 3-4). Again, this is because both solar output and peak load in California are ultimately driven by the sun. Geothermal also has a high capacity credit, not due to any coincidence with load, but because geothermal is essentially a fuel-based renewable that behaves much like a conventional resource (i.e., geothermal is not intermittent). Three wind farms—Altamont, San Gorgonio, and Tehachapi—have capacity credits on the order of 22 percent. This lower number represents the fact that wind is not directly linked to load, but still shows some correlation.

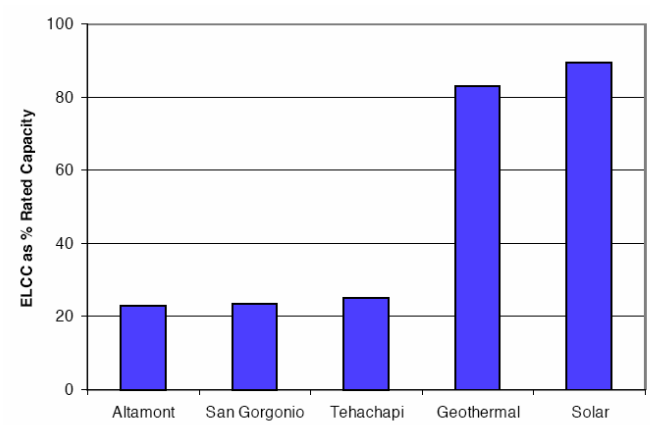

Figure 3-4
California's 2004 RPS Integration Study using the ELCC Method to Compare Renewables to a Gas Benchmark Unit[9]

[8] California Wind Energy Collaborative. (2004) *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis, Phase III: Recommendations for Implementation*. California Energy Commission.
[9] Milligan, M. and Porter, K. (2005). *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. Windpower 2005 Conference.

Additional U.S. studies consistently show a positive reliability value for intermittent renewables such as wind (see Figure 3-5).

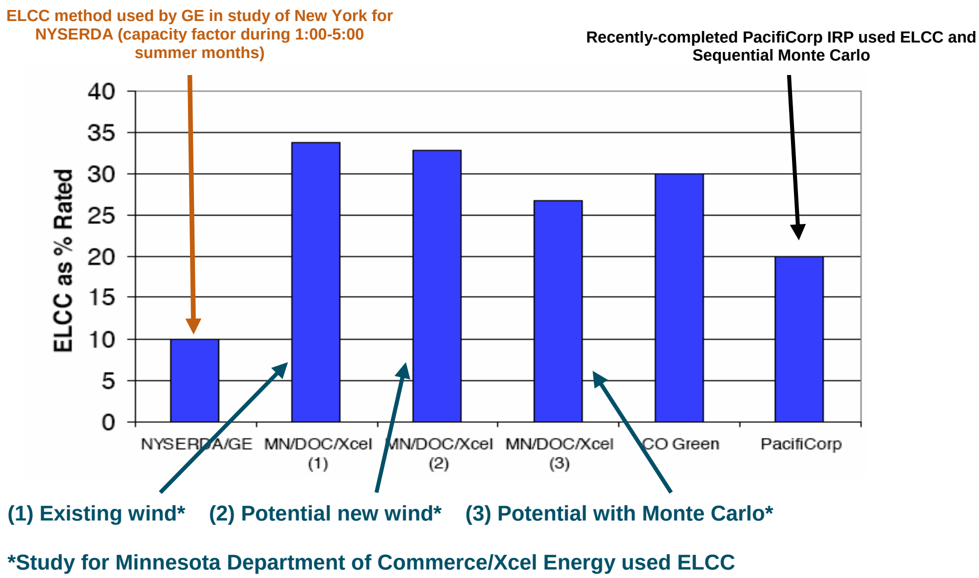

Figure 3-5
ELCC Comparison for Renewables throughout the U.S.[10]

It is also important to understand how capacity credit changes as the penetration of intermittent generation within a system increases, since it is reasonable to assume that variability will increase as the total rated wind capacity increases. Combining the results of several U.S. and European studies, including discrete analyses of strictly parameterized scenarios and analyses across a range of penetration rates, reveals notable trends in both the benefits and costs of renewable resources. As shown in Figure 3-6, many studies found that the marginal reliability contribution of intermittent renewables decreases as the penetration rate rises.

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[10] *Id.*

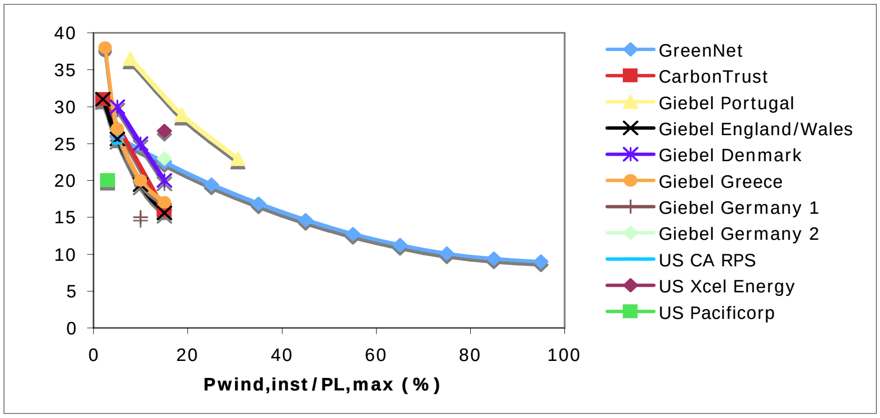

Figure 3-6
Reliability Credit as a Function of Wind Penetration[11]

Accordingly, it is also reasonable to assume that operational integration costs would increase as capacity credit decreases.

Implications

The combination of these two trends—decreasing reliability contribution and increasing marginal integration costs—suggests that some optimum renewable penetration rate exists where the marginal reliability benefit equals the marginal integration cost. This implies that the importance of forecasting and storage rises with increasing intermittent renewable penetration rates. Since forecasting addresses the predictability of intermittent generation, more accurate forecasting can lead to significant economic value. As Christian Nabe[12] describes,

> "If wind prediction were too pessimistic and produced electricity was abundant, prices on the balance market are lower than spot market prices which results in a loss of revenue. If predictions were too optimistic and wind energy falls short of sold capacity, energy has to be purchased from the balance market at any price to meet the contract obligations which means a loss as well."

[11] Auer, H. *et al.* (2004) *The GreenNet Project: Costs and Technical Constraints of RES-E Grid Integration*. www.GreenNet.at; The Carbon Trust & DTI. (2003) *Renewables Network Impact Study: Annex 4.*; Commission of the European Communities. (1992) *Wind Power Penetration Study* (Case Studies for Portugal, the UK CEGB System, Denmark, Greece, and Germany). EUR 14245 EN, EUR 14247 EN, EUR 14248 EN, EUR 14252 EN, EUR 14249 EN, (Brussels/Luxembourg); Jarass, L. (1981) *Strom aus Wind: Integration einer regenerativen*

[12] Nabe, C. (2000) *Capacity Credits for Wind Energy in Deregulated Electricity Markets – Limitation and Extensions*. Technische Universitat Berlin, Institute of Technology and Management, Division of Energy Economics and Management.

In Hawaii the consequences of inaccurate forecasting are even more severe. The utilities in Hawaii do not have the option of buying electricity from a neighbor or market, so if predictions are too optimistic and there are not adequate reserves on the system, the utility will not be able to meet customer demand. Storage at different timescales can also be an important tool in managing unpredictable variation in output and in capturing excess power generation during off-peak periods. Each of these tools aids in reaching the optimum penetration level without sacrificing reliability benefits or paying unnecessary costs.

Both the theory and empirical results discussed above suggest that intermittent renewables do contribute to the reliability of a power system. While this contribution depends on the correlation of weather to both load and power output, the inherent variability of weather—and therefore renewable power output—does not preclude its consideration as a reliable power generator.[13] After all, conventional power generators also suffer from variability in that there is a non-zero probability of failure for any given unit. The marginal value of intermittent renewables initially rises due to the portfolio effect, which smoothes some variability in output. However, the reliability value of intermittent renewables declines with increasing penetration rates. We note that system integration costs are utility-specific and depend on the existing system configuration and reserves, but also that they tend to rise with increasing penetration rates. Combining renewables with forecasting, to mitigate the unpredictability of weather, as well as with quick generation and storage, allows the utility to increase and fine-tune its renewable penetration rate with less risk of sacrificing reliability benefits associated with renewable generation.

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[13] On small systems such as HELCO and MECO with small amounts of regulating reserves, the ability to regulate system frequency, regulate voltage, and and support the grid through fault conditions need to also be examined. In contrast, run-of-river hydro has less reliability impact and although it is not dispatchable, it has higher predictability and less variability.

4

PORTFOLIO COVARIANCE AND CORRELATION TO PEAK

As mentioned in the previous chapter, after examining the relationship of both renewable power output and power demand caused by the weather, the next step is to assess the potential correlation and covariance between renewable power output and load, and between different renewable generators. We are primarily interested in the impact of renewable generation during peak hours, when capacity is most valuable.

Covariance with Load

There are several simple statistical analyses that can be performed in order to understand an intermittent generator's covariance with load. The first simple analysis looks for observable trends in monthly average renewable power output (or wind speed) and monthly average load. As can be seen in the figure below, an ideal situation is characterized by high wind speeds producing, obviously, high wind power output that is concurrent with high power demand (see Figure 4-1).

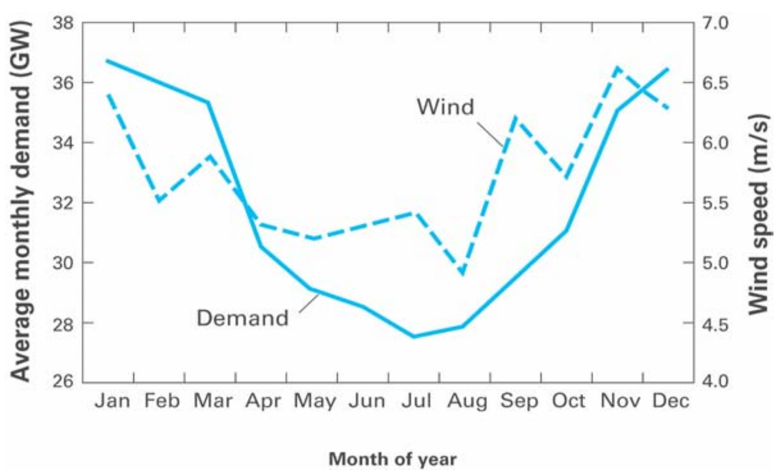

Figure 4-1
Correlation of Wind and Electricity Demand in England[14]

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[14] Thresher, R. (1996) *Wind as a Distributed Resource*. Electric Power Research Institute 2nd DR Conference.

Monthly scatterplots of hourly load versus hourly renewable power output (see Figure 4-2) can provide a more consolidated view of the covariance between these two variables. Data points clustered in the upper right quadrant of the chart suggest positive covariance dominates the dataset. Clustering in the upper left or lower right quadrants suggests negative covariance, which is unfavorable for renewable reliability credit. Clustering in the lower left quadrant suggests little covariance in peak periods but is not specifically detrimental to system reliability—the renewable output is just not as valuable.

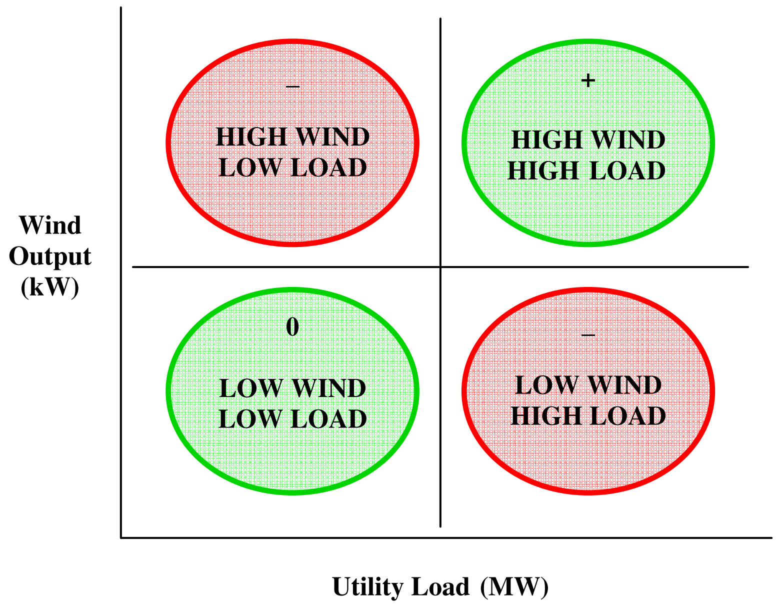

Figure 4-2
Stylized Scatterplot of Renewable Power Output versus Utility Load

The covariation between load and renewable power can be calculated on shorter time scales as well. On a daily basis, a large positive covariance (or a correlation close to one) is desirable because it indicates that load and renewable output vary together—when there is high load demand there is likely to be high renewable power available. Of course, daily correlation values in the annual peak period are of the most interest, and should be the focus of this analysis.

Finally, a least-squares method can be used to fit a Weibull distribution to actual wind speed data for each of the twenty-four hours in a day. From this fitted distribution, it is possible to determine the minimum wind speed that is likely to occur for each hour consistent with some desired confidence level (for example, 95 percent confident of getting at least a particular wind speed). Ideally, Fitted Weibull distributions should be normally distributed around higher wind speeds (see Figure 4-3). Splitting the series according to hour allows a utility to again focus on the peak periods and assess expectations for wind speed. Additionally, we can determine the probability of experiencing wind speeds below the cutoff speed for a specific turbine.

As can be seen in the following figure, an afternoon peaking utility would be satisfied with this set of distributions because wind speeds in the afternoon tend to be high and are very rarely below the wind turbines cut-in wind speed. However, an evening-peaking utility would find this set of distributions less attractive, since wind speeds in the evening are lower and have a non-insignificant probability of producing zero power.

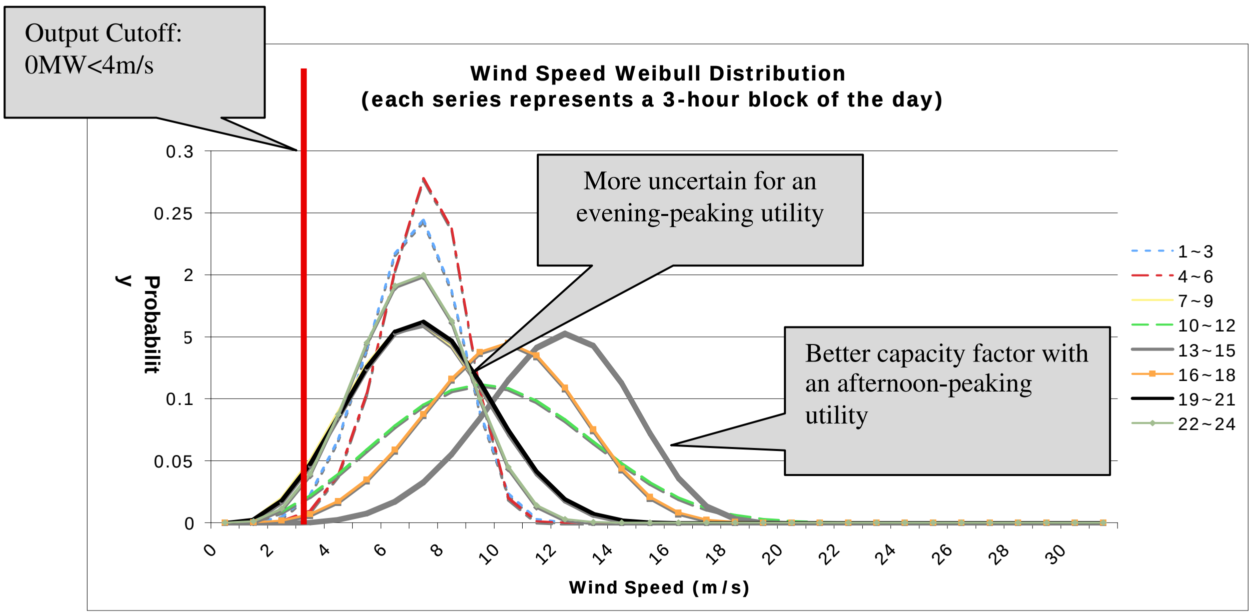

Figure 4-3
Wind Speed Weibull Distribution

Peak Coincidence

There are two peak periods of primary interest: daily peak and annual peak. As a descriptor of daily correlation to peak power demand, we identify the capacity factor for the renewable resource in the peak hours of each day (that is, the peak one, three, or five hours of the day). We define capacity factor as the ratio of average observed output to maximum possible output. This analysis allows us to identify the frequency of observing zero for a capacity factor as well as the average capacity factor over a given period. The higher the expected capacity factor, the more power expected from the renewable resource during peak periods.

Analyzing capacity factor in annual peak periods can provide approximations of effective load carrying capability (ELCC) for a renewable generator. ELCC is a measure of reliability defined in terms of megawatts, and estimating ELCC for generators that are not perfectly reliable—and as discussed previously, no generator is perfectly reliable—can be quite complex and may incur a significant cost in terms of data collection, analysis, expertise, and computer time since it often requires reliability models and generating data from conventional power plants. Simplified methods of approximating ELCC have been developed but increased simplicity can imply a sacrifice in accuracy. Four basic simplified methodologies have emerged[15]:

1. Calculate capacity factor in top load hours;
2. Calculate capacity factor in weighted top load hours;
3. Calculate capacity factor in top loss-of-load probability (LOLP) hours; and
4. Calculate capacity factor in weighted top LOLP hours.

Loss-of-Load Probability hours and top load hours differ primarily due to hydro resources, which often have seasonal trends in availability. Since our model was developed with the Hawaiian utilities in mind and these utilities have minimal hydro resources in the power mix, we discuss only the first two calculations.[16] To find the capacity factor in the top load hours, the model first must sort the load data in descending order and then identify the user-specified percentage of hours (e.g., top 1 percent, 5 percent, etc.). The model then applies the following formula:

$$CF = \frac{\frac{1}{h}\sum_{i=1}^{h} p_i}{p_{\max}},$$

Where *CF* is the capacity factor, *h* is the total number of hours included, p_i is the renewable power output associated with a given hour (*i*), and p_{max} is the maximum possible renewable power output. To arrive at an approximation of ELCC, simply multiply the capacity factor by the generator's rated capacity. This approach generally underestimates the true ELCC, however, because it counts each hour within the specified top percentage equally. In reality, it is more valuable to have demand in the top-most load hour met than in any lower hour; this also holds true for subsequent load hours. Therefore, the method that calculates capacity factor in the weighted top load hours is more accurate. This method applies the following two formulae to the user-specified top percentage of hours:

$$CF_{weight} = \frac{\sum_{i=1}^{h} p_i w_i}{p_{\max}} \text{ and } w_i = \frac{l_i}{\sum_{i=1}^{h} l_i},$$

[15] Development of these methodologies has been largely conducted by Michael Milligan. See for example: Milligan, M. and Parsons, B. (1997) *A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators*. National Renewable Energy Laboratory. NREL/CP-440-22591.; Milligan, M. *et al.* (2005) *Determining the Capacity Value of Wind: A Survey of Methods and Implementation*. National Renewable Energy Laboratory. NREL/CP-500-38062.

[16] The exception is HELCO, which has 15 MW of hydro, representing a significant source of energy for its system size.

Where CF_{weight} is the weighted capacity factor, h is the total number of hours included, p_i is the renewable power output associated with a given hour (i), p_{max} is the maximum possible renewable power output, w_i is the weight associated with a given hour, and l_i is the load associated with a given hour. In this way, the highest load hours are given more importance in determining the capacity factor.

After performing their own analyses using the more rigorous ELCC methods and the simplified methods, Milligan and Parsons[17] recommend using the more complex ELCC methods and a full complement of reliability models. They recognize, however, that there may be instances where this is impossible. Based on the performance of the simplified methodologies in terms of root-mean-square error statistics, Milligan and Parsons suggest using the risk-hour methods before the load-hour methods because the risk-hour procedure incorporates information from a reliability model. However, they cite the load-hour methods as providing a "reasonable approximation" if data and technological capabilities are limited.

Portfolio Approach

After analyzing an intermittent generator's covariance with load and correlation to peak, the next step is to analyze whether intermittent generators exhibit any covariance with *each other*. That is, what are the impacts to reliability of considering several intermittent generators together as a portfolio?

Conventional wisdom holds that capacity credit is given to an individual generator based on the individual generator's characteristics.[18] This philosophy generally leads to the assumption that wind farms have little or no capacity value because the degree of variability of the resource is so high at each individual site.[19]

Modern financial portfolio theory, though, offers a different way of looking at the world. A financial portfolio consists of a combination of individual stocks.[20] Developed by Harry Markowitz in 1952, modern portfolio theory enables the creation of minimum-variance portfolios for a given level of expected return.[21] This theory is based on diversification—the lower the correlation between the individual assets that make up the portfolio, the lower the portfolio variance (risk).[22]

Take, for example, a simple two-stock portfolio with the characteristics shown in Table 4-1.

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[17] Milligan, M. and Parsons, B. (1997). *A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators*. National Renewable Energy Laboratory. NREL/CP-440-22591.
[18] Milligan, M. (2002). *Modeling Utility-Scale Wind Power Plants Part 2: Capacity Credit. National Renewable Energy Laboratory.* NREL/TP-500-29701.
[19] Kirby, B. *et al.* (2004). *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis, Phase III: Recommendations for Implementation.* California Energy Commission.
[20] Alexander, C. (1996). *Handbook of Risk Management and Analysis*. John Wiley & Sons.
[21] *Id.*
[22] *Id.*

Table 4-1
Simple Two-Stock Example

Stock	% in Portfolio	Expected Return (%)	Expected Standard Deviation (%)
Stock 1	65	10	31.5
Stock 2	35	20	58.5
Total Expected	100	(0.65*10) + (0.35*20) = 13.5	?

Non-portfolio thinking would hold that the total expected standard deviation should be the weighted average of the standard deviations of the two individual stocks. This approach leads to a portfolio standard deviation of 41 percent. However, that assumes *incorrectly* that stocks exhibit perfectly positive correlation, which is highly unlikely. Instead, it is critical to account for the covariation of stocks. Including this covariation in the portfolio standard deviation calculation leads to a portfolio standard deviation of 31.7 percent, significantly lower than the weighted average of 41 percent. The point of this example is that the covariation of stocks, derived from the fact that stocks do not generally move in perfect lock-step, means that a portfolio of stocks has a smaller standard deviation than simply the average of the individual stocks.

In Figure 4-4, the curved line illustrates how expected return and standard deviation change as you hold different combinations of two stocks. This is known as the portfolio efficient frontier, and was also developed in the 1950s by Markowitz. Portfolios below the curve are not efficient, because a greater return could be achieved for the same risk. Portfolios above the line are impossible. Portfolios on the line represent the portfolio with the highest return for a given risk level, and involve different quantities of each stock.

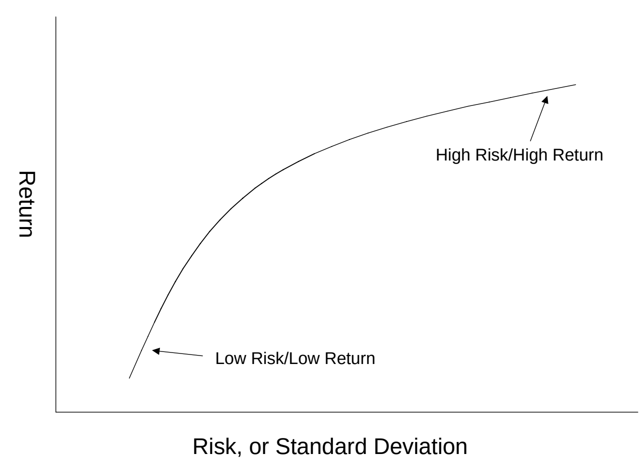

Figure 4-4
Portfolio Efficient Frontier

Financial portfolio theory can be easily applied to energy resources. In this context, a renewable portfolio could comprise either multiple renewable resources (e.g., wind, solar, etc.) or a single renewable resource that is geographically dispersed. When using portfolio theory to analyze the reliability impacts of renewables, there are two time frames of interest. If using this type of analysis by itself, it is helpful to look at portfolio impacts during the utility's annual peak period. However, if using this type of analysis as part of a larger reliability analysis (e.g., ELCC), the portfolio should be analyzed for the entire year in order to provide appropriate input data for further analysis. Finally, it is important to recognize that portfolio analysis can be used to value existing resources *and* as a tool to plan for future resource additions.

Portfolio diversification is discussed here as applied to wind power. Due to topography and meteorology, winds in different geographic locations are often not correlated while sometimes they are negatively correlated.[23] By blending individual sites together into a portfolio, the overall risk, or variability, of portfolio power production should be reduced.

Take, for example, three geographically dispersed wind farms as described in Table 4-2.[24] It shows each wind farm's average power output and the total site variability for each 1.65 MW turbine at that site for the utility's annual peak period.

Table 4-2
Three Wind Farms Average Power Output and Total Site Variability

Site	Mean (kW)	Total Variability
Site 1	870	220,000
Site 2	950	400,000
Site 3	650	320,000

As can be seen in the following site probability distributions (Figure 4-5),[25] power outputs are not normally distributed because the power conversion function is non linear. So while wind speeds might appear normally distributed, we should not expect power outputs to be. Because wind turbines have a cut-in wind speed of about 4 meters per second (m/s), all speeds below that produce zero power output, and there can therefore be a higher probability of getting zero power. Likewise, once the wind speed reaches roughly 13 m/s, the turbine produces a constant power output of 1650 kW, and thus there is a higher probability of producing the maximum power output.

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[23] Milligan, M. (2002) *Modeling Utility-Scale Wind Power Plants Part 2: Capacity Credit*. National Renewable Energy Laboratory. NREL/TP-500-29701.
[24] The following discussion is adapted from Hansen, L. (2004). Can Wind be a 'Firm' Resource? A North Carolina Case Study. *Duke Environmental Law & Policy Forum*. Data is based on measurements from three sites in North Carolina.
[25] *Id.*

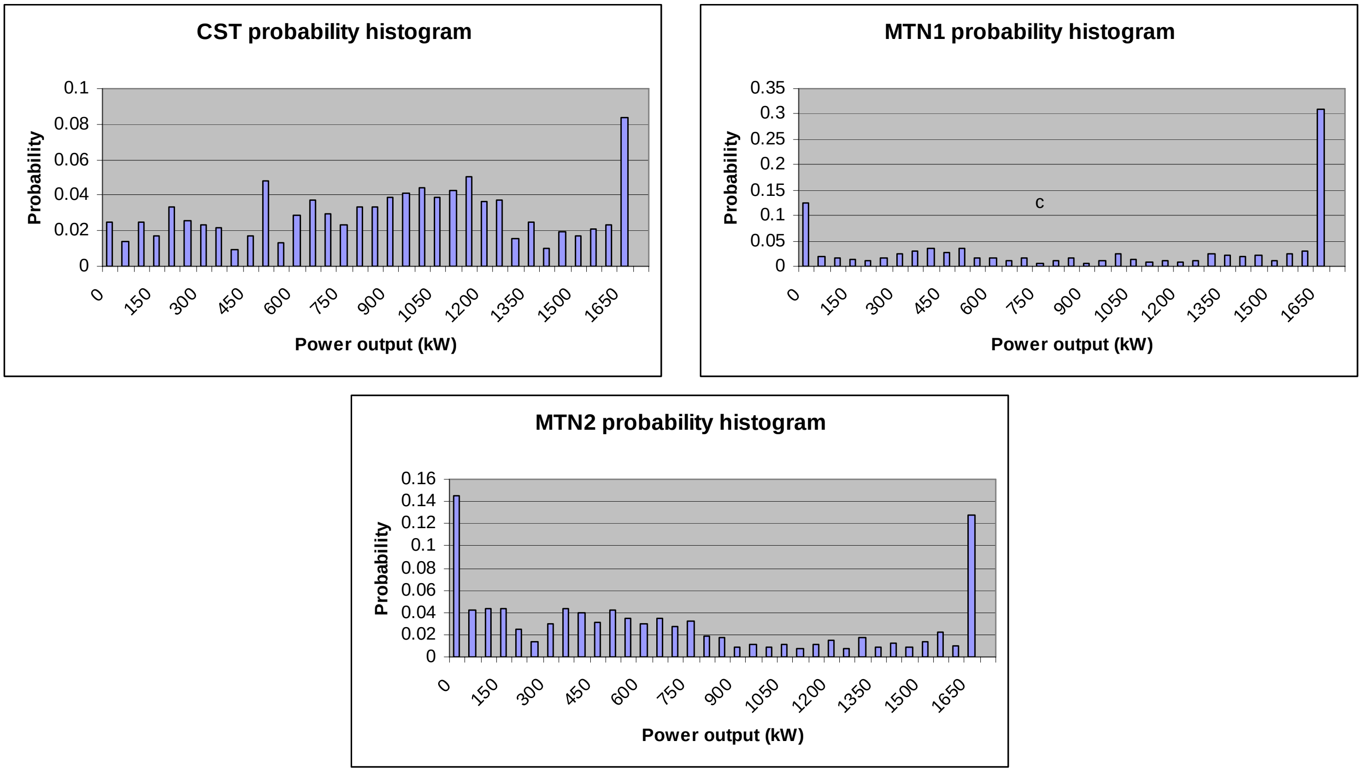

Figure 4-5
Site Probability Distributions

As expected, the power outputs of turbines at these three sites during the annual peak period exhibit extremely high variability. At each of the three sites, there is generally less than a 5 percent probability of getting any particular power output other than zero or the maximum.

Because the power distributions are not normally distributed, the standard deviations reported here for each site are not equivalent to standard deviations in normally distributed functions. However, the standard deviation still serves as a valuable indicator of variability.

High variability, as seen here, is often the primary concern cited by electric utilities. The question here is whether geographically distributing wind generation effectively raises the capacity value of the system by decreasing this variability. Geographical distributions of wind resources have been considered in other studies, although not, as yet, in great detail. In 2002, Eric Hirst, a consultant for the Bonneville Power Administration (BPA), suggested that the variability of the output of wind generation at dispersed locations would be less than the variability of co-located wind generation.[26] Hirst found that the standard deviation of the total

[26] Hirst, E. (2002). *Integrating Wind Energy with the BPA Power System: Preliminary Study*. Power Business Line, Bonneville Power Administration.

output of five dispersed wind farms would have been 30 percent lower than the standard deviation had they been co-located.[27]

The first step in determining the value of geographical dispersion for this portfolio is to determine whether the three sites exhibit any covariance. That is, are large power output values at one site associated with large power output values at another site (positive covariance), are the power output values unrelated (covariance near zero), or are large power output values at one site associated with small power output values at another site (negative covariance)?

A covariance matrix was generated for the annual peak period (see Figure 4-6), according to the formula:

$$\text{cov}(x,y) = 1/n^{*}\Sigma\,(x_i - \mu_x)(y_i - \mu_y)$$

x, y = data series
n = number of data points
μ = data series average
I = data point

Annual Peak Covariance Matrix

	Site 1	Site 2	Site 3
Site 1		— -24631	— -18026
Site 2	— -24631		+ 115744
Site 3	— -18026	+ 115744	

Figure 4-6
Annual Peak Covariance Matrix

[27] *Id.*

As can be seen in the above matrix, there is some degree of negative covariance between the three sites. Specifically, Sites 1 and 2 and Sites 1 and 3 exhibit negative covariance during the annual peak, while Sites 2 and 3 exhibit positive covariance. Positive covariance between Sites 2 and 3 is not particularly surprising, since they are geographically closer to one another than to Site 1 and therefore likely share some topographical and meteorological characteristics.

The simplest application of modern portfolio theory is to an existing portfolio of resources. In this case, simply calculate the combined output and variation, according to the following equations:

$$P_{total} = \overline{p_1} s_1 + \overline{p_2} s_2$$
$$V_{total} = v_1 s_1 + v_2 s_2 + 2\mathrm{cov}(v_1, v_2)$$

where P_{total} is the portfolio output, V_{total} is the portfolio variance, p_i is the individual site output, v_i is the individual site variance, and s_i is the share at each site.

With more than two sites, simply add terms for the covariation between all combinations of sites.

The more complex, but potentially more useful, application is in designing a new portfolio or new additions to an existing portfolio. In this case, new additions can be optimally sited to minimize portfolio variability. The value of this negative covariance in reducing system variability is determined by running an optimization model to determine the mix of generation at each site that would yield the collective minimum variability.

This optimization problem minimizes the portfolio variability by changing the share of wind at each site, subject to several constraints, according to the following form:

minimize: $s'\Omega s$

by changing: s

subject to: $0 \le s \le 1$

$s'i = 1$

$s'\mu \ge \mu_{min}$

where:

$$\Omega = \text{covariance matrix} = \begin{bmatrix} \sigma_1^2 & \sigma_{12} & \sigma_{13} \\ \sigma_{21} & \sigma_2^2 & \sigma_{23} \\ \sigma_{31} & \sigma_{32} & \sigma_3^2 \end{bmatrix}$$

s = shares vector = $\begin{bmatrix} s_1 \\ s_2 \\ s_3 \end{bmatrix}$

i = $\begin{bmatrix} 1 \\ 1 \\ 1 \end{bmatrix}$

μ = mean output vector = $\begin{bmatrix} \mu_1 \\ \mu_2 \\ \mu_3 \end{bmatrix}$

μ_{min} = specified minimum portfolio weighted power output

Variance is not independent of average—as portfolio average power output increases, variance increases. While minimal variability in power output is desirable, some higher level of variability might be acceptable in order to achieve a higher average output. The decision to accept a higher level of variability is based on the individual risk preferences of the wind developer and utility, and the comparative value of energy and capacity payments. If capacity is more valuable, a developer may choose a portfolio with a lower output and correspondingly lower variance. However, if energy is more valuable, a developer may choose a portfolio with a higher mean output and variance, thereby giving up possible capacity payments.

The following graph describes the mean-variance efficient frontier for the annual peak period (see Figure 4-7). Different mean portfolio outputs are associated with different portfolios of wind (i.e., a different percentage of the total wind capacity at each site).

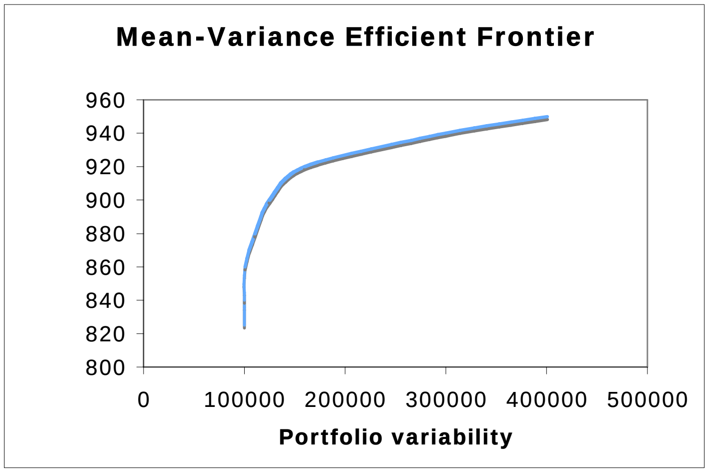

Figure 4-7
Annual Peak Mean-Variance Efficient Frontier

During this period, Site 2 has the highest mean output of the three sites. Therefore, the point (952, 387000) represents the portfolio with 100 percent of the wind turbines at Site 2. As wind is added at the other two sites, portfolio variance decreases, but so does mean portfolio output, according to the above mean-variance frontier. This analysis is focused on the potential for capacity credit, so the portfolio that has the absolute lowest variability is shown below in Table 4-3.

Table 4-3
Annual Peak Portfolio

Site 1 Share (%)	Site 2 Share (%)	Site 3 Share (%)	Mean Power Output (kW)	Standard Deviation (kW)
52	21	27	830	315

Shares at each site are given as percentages because shares are independent of the total amount of wind. For example, if a developer wanted to install a total of ten wind turbines, this portfolio would require five be installed at Site 1, two at Site 2, and three at Site 3. If twenty wind turbines were desired, ten would be installed at Site 1, four at Site 2, and six at Site 3.

The Figure 4-8 depicts the probability histogram for this lowest variance portfolio during the annual peak period. It represents the weighted average of the probabilities of the three individual sites during this time period. Aggregation of the three individual sites results in a distribution substantially closer to normal.

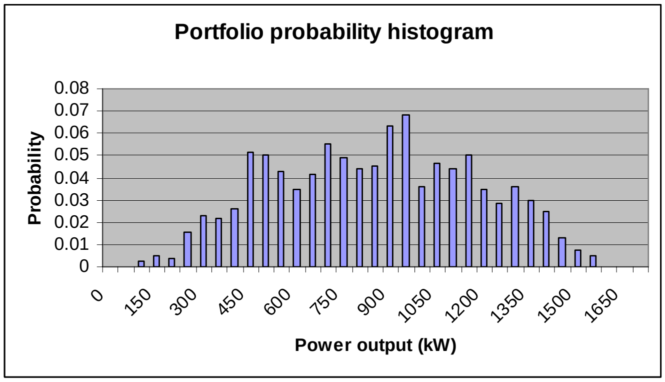

Figure 4-8
Portfolio Probability Histogram

As can be seen in Table 4-4, the standard deviation of the combined output is substantially less than any of the three individual sites. This result occurs because, as shown by the largely negative covariance between sites, the sites are geographically dispersed and therefore the wind at each site is not entirely correlated. The variation at one site to some degree cancels the variation at another site.

Table 4-4
Site and Portfolio Average Output and Standard Deviation

Site	Average Output (kW)	Standard Deviation (kW)
1	870	470
2	950	630
3	650	570
Portfolio	830	310

While this smaller variability is good, the absolute magnitude of the variability is still quite large. The capacity credit given to fossil-fuel power plants is less than rated capacity, because there is always some probability, no matter how small, that the plant will fail and therefore not be available when needed.[28] Therefore, wind should be given capacity credit for the power output generated with 95 percent confidence. In a normal distribution, this level is represented by the mean power output minus 1.645 standard deviations.[29]

[28] Milligan, M. (2002). *Modeling Utility-Scale Wind Power Plants Part 2: Capacity Credit*. National Renewable Energy Laboratory. NREL/TP-500-29701.
[29] Pearson, E. and Hartley, H. (eds.). (1966). *The Biometrika Tables for Statisticians*. (Vol. 1, 3d ed.) Biometrika.

Because the lowest variability portfolio distributions for the annual peak period are not precisely normally distributed, the 95 percent-level was calculated by using a histogram of power output, and then determining the capacity value that resulted in a 0.95 cumulative probability. Based on this methodology, this portfolio contributes 340 kW of capacity credit during the annual peak period.

The mean-variance frontier for the annual peak period is relatively flat until roughly 900 kW mean portfolio output, at which point variance rises sharply. It is likely that a developer would prefer a portfolio at this point because while the mean portfolio output is substantially higher than the minimum, variance is only slightly higher.

The benefits of developing a portfolio of different renewable resources or of geographically dispersed renewable resources are clear, and should be taken into consideration when analyzing the reliability impacts of renewables on an electric system.[30]

[30] Of course, if different wind sites exhibit positive covariance, variability impacts could be magnified. Regardless, the impacts of portfolio covariance should be analyzed, as either result is useful.

5
METHODS OF MEASURING RELIABILITY IMPACT

Effective Load Carrying Capability

Evaluating the reliability value of intermittent generators is more complicated than evaluating the reliability for conventional generators—but not impossible. There are analytical methods for correctly accounting for the value that intermittent generators provide to system reliability—because after all, *system* reliability should be the goal, not individual plant reliability. System reliability as discussed here is measured probabilistically by nearly all electric utilities as Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE), which will be discussed in more detail in the following section. Capacity credit, as discussed here, is the capacity a given generator adds to the electrical system as compared to a fossil-fuel-based conventional generator that would add the same level of system reliability. In other words, for intermittent generators, capacity credit is equal to the amount of conventional generation that could be displaced by the intermittent generator.

There are several methods currently being used by utilities to measure capacity credit, but the most common is effective load carrying capability (ELCC). ELCC is a way to measure a power plant's capacity contributions based on its influence on overall system reliability, and is based on traditional utility reliability analysis in conjunction with statistical methods drawn from a large established literature in both the United States and Europe.

Nearly all electric utilities measure reliability probabilistically using Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE). LOLP is defined as the probability that enough generators will fail in any given hour that load cannot be met, and is therefore a value between zero and one. This probabilistic measure recognizes that there is always some small probability that even a conventional generator will not be available (e.g., be on forced-outage). LOLE is represented as the sum of LOLP values over a given time period, and is often expressed as days per year, days per 10 years, or hours per year. A typical value is 1 day in 10 years.

Values of LOLP are calculated by using an existing utility reliability model with hourly loads and generator characteristics such as capacity and forced-outage rates (FOR). For each hour, a capacity table is calculated that shows levels of generation and associated outage probabilities, and unavailable generation and associated probabilities.

As exerpted from Milligan, the usual formulation of annual LOLE, based on hourly LOLP values, is shown below.[31]

$$LOLE = \sum_{i=1}^{N} P(C_i < L_i)$$

where *P()* denotes the probability function, *N* is the number of hours in the year, C_i represents the available capacity in hour *i*, and L_i is the hourly utility load. To calculate the additional reliability that results from adding wind generators, we can write *LOLE'* for the LOLE after intermittent capacity is added to the system as:

$$LOLE' = \sum_{i=1}^{N} P[(C_i + W_i) < L_i]$$

where W_i is the power output from the intermittent generator during hour *i*. This equation can be rewritten to include several intermittent generators as:

$$LOLE' = \sum_{i=1}^{N} P[(C_i + \sum_{j=1}^{N_w} W_{i,j}) < L_i]$$

where N_w is the number of intermittent sites in the analysis, *j* indexes N_w, and $W_{i,j}$ is the intermittent power output at hour *i* from site *j*. The ELCC of the system is the load that can be supplied at a specified level of risk of loss of load.

$$\sum_{i=1}^{N} P(C_i < L_i) = \sum_{i=1}^{N} P[(C_i + \sum_{j=1}^{N_w} W_{i,j}) < (L_i + E_i)]$$

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[31] Milligan, M. (2002). *Modeling Utility-Scale Wind Power Plants Part 2: Capacity Credit*. National Renewable Energy Laboratory. NREL/TP-500-29701.

Calculating the ELCC of the intermittent generator amounts to finding the values E_i, for which this equation says that the increase in available capacity can support E_i more MW of load at the same reliability level than the original load that could be supplied with C_i MW of capacity."

The advantages of calculating ELCC in this way is that it can be applied to any type of generator, and therefore does not penalize or reward any particular type of generator.

Characterization of Intermittent Generators in Production-Cost Models

Whereas conventional generators have forced-outages based on mechanical failure, intermittent renewables have forced outages based on "fuel" availability. Because traditional utility production-cost models are not designed to recognize and accurately incorporate intermittent generators into the model, the intermittent generator must be made to mimic a conventional generator. There are several methods available that allow renewables to mimic conventional generators. These methods fall into two broad categories: demand-side and supply-side, and the discussion of both is based on Milligan.[32]

Choosing to treat an intermittent generator as a demand-side resource means that the intermittent output is considered to be a negative load. The three methods for defining intermittent resources as supply-side resources include:

- Sliding Window estimate for Effective Forced Outage Rate;
- Stochastic Multi-block method; and
- State Transition Matrix method.

Load Modifier Method

On the demand-side, an intermittent generator can be modeled as a load modifier. In this case, the intermittent power production is simply subtracted from the load before conventional supply-side resources are dispatched.

The advantage of this approach is that it takes the hourly variability of intermittent power into account. However, the stochastic nature of the wind resource, and therefore the reliability impact, is underestimated, since the historical data is treated as certain.[33] However, when used in a post-facto analysis aimed at giving capacity payments to intermittent generators for capacity in some previous time period, this analysis is very robust. This type of post-facto analysis is currently being used by both PJM and the California electric system.

Supply-Side Approaches

As a supply-side resource, the intermittent generator is economically dispatched along with conventional generators. Since economic dispatch is based on the marginal operating costs of generators, intermittent renewable generators that have zero fuel cost should be dispatched first.

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[32] Milligan, M. (2000). *Modeling Utility-Scale Wind Power Plants Part 1: Economics*. National Renewable Energy Laboratory. NREL/TP-500-27514.
[33] *Id.*

Including the intermittent generator in the LOLP calculation in this way should result in a more accurate reliability impact answer.[34]

An important note that will be discussed later in more detail is that for an intermittent renewable generator to be accurately modeled as a supply-side resource, there must be sufficient power output data to allow for a robust statistical evaluation of the likelihood of power being produced in any particular hour. Typically, at least three years of historical hourly data is needed, and preferably more.

Effective Forced-Outage Rate and Sliding Window Approximation

As the forced-outage rate of a generating unit increases, its ELCC decreases.[35] However, even for very high forced-outage rate, the ELCC is not zero. A simple, although basic, method of determining an intermittent generator's capacity credit is to estimate an "effective" forced-outage rate as (1- capacity factor) during top load hours.

A more accurate method could be the Sliding Window approximation, which is a method under development by the National Renewable Energy Laboratory,[36] and is a variation on the effective forced-outage rate approach. Under this method, a "window" is a set number of consecutive hours, and the effective forced-outage rate is (1- capacity factor) during those hours. The window then slides over one hour and calculates the effective forced-outage rate again.[37] In essence, this is a more sophisticated approach because it accounts for variation over time.

Stochastic Multi-Block Method

A more sophisticated approach is the Stochastic Multi-block Method. In some reliability models, generators are characterized by several "blocks," or output levels, each with a different heat rate and forced-outage rate. According to Milligan, in this approach, "the intermittent resource is modeled as if it were a conventional, multi-block thermal unit, with each block having its own availability (or conversely, its own forced-outage rate)".[38]

In this instance, intermittent output must first be transformed into a probability distribution. The intermittent output can then be modeled as a series of discrete generation levels for each hour of the day in a given month. In other words, a total of 24 distributions are created for each month of the year. This information is then fed into a load-duration curve production-cost model as a series of time-varying probabilities for the month.[39]

The problem with this approach is that it tends to smooth the actual variations. Further, not all production-cost models have the capability to vary forced-outage rates for a single generator. The advantage, however, is that this method presents a more accurate representation of reliability

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[34] *Id.*
[35] Milligan, M. (2005). *Capacity Credit for Wind*. National Renewable Energy Laboratory, Utility Short Course.
[36] *Id.*
[37] *Id.*
[38] Milligan, M. (2000). *Modeling Utility-Scale Wind Power Plants Part 1: Economics*. National Renewable Energy Laboratory. NREL/TP-500-27514.
[39] *Id.*

than the load-modifier approach. It fits well with many planning models and can vary monthly, as well as capture time-of-day variations.

State Transition Matrix Method

A state transition matrix (STM) captures the time-varying properties of wind speed, recognizing that the probability of a particular wind speed occurring during any hour depends only on the wind speed in the previous hour. This is known mathematically as a Markov model, and is a form of conditional probability. It can be expanded to include the previous two hours, which allows the model to account for trends in wind speeds.[40]

Similar to the Stochastic Multi-block Method, the STM is a series of probability distributions. One distribution is calculated for each wind speed or power output level to define the probability of changing to all other wind speeds or power outputs. This method recognizes that wind speeds generally change gradually, except during stormy periods.[41]

This method has several potential shortcomings. Many production-cost models are incapable of analyzing STMs. Of those that are, some may only allow for a single STM per year, which is not sufficient to capture the variation of intermittent generation. It might be possible to get around this obstacle by breaking an intermittent generator into twelve “separate” plants, each only available for one month. STMs can be constructed outside of the production-cost model, but this can be expensive. The advantages of this method are that it handles the stochastic nature of the intermittent resource, and picks up the hourly transition between states.

The choice of characterization method is in large part based on the particular characteristics of the production-cost model being used. In addition, the purpose of the capacity credit analysis must be considered. If the utility is interested in capacity planning, a supply-side approach is more appropriate, since these methods more accurately capture the stochastic nature of the intermittent resource. However, if the utility is interested in making payments for past reliability contributions, the demand-side load-modifer approach is more appropriate.

A step-by-step guide to ELCC calculation can be found in the California Energy Commission’s Renewable Portfolio Standard Phase 3 report.[42]

Other Methods

Several utilities have developed methods of valuing capacity credit different from ELCC. Often, these methods are approximations used to avoid the computationally complicated ELCC calculation. Most of these methods involve determining the wind power output for a specified time period.

For example, one method takes the capacity credit to be the median wind power output during the peak four hours of a month, and then recalculates this value each month. Another method is to calculate the 85th percentile wind power output during the top 10 percent of load hours during each month, and then take that value as capacity credit. This method also recalculates capacity

[40] *Id.*
[41] *Id.*
[42] Kirby, B. *et al.* (2004). *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis, Phase III: Recommendations for Implementation*. California Energy Commission.

credit each month. Finally, capacity credit can be taken as the capacity factor during some percentage of top load hours.[43]

Properties of a Good Metric

Milligan has identified eight characteristics of a good capacity credit metric[44]:

- Is equitable in the way all generators (conventional and intermittent) are treated;
  - Horizontal equity: two generators with identical (similar) reliability properties should be treated identically (similarly), and
  - Vertical equity: a generator with higher reliability/ability to deliver on peak should have higher capacity value than generator that is not able to consistently deliver;
- Is based on accepted reliability theory and practice;
- Reflects the risk-reduction contribution of any generator;
- Captures the importance of load shape;
- Reflects delivery pattern relative to load shape;
- Mathematically consistent;
- Is data driven; and
- Is simple.

While the ELCC method is not transparent or simple, it is preferable to both the median value during peak and the 85th percentile in top load-hours methods.

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[43] Methods for calculating capacity credit at utilities around the United States are summarized in: Milligan, M. and Porter, K. (2005). *Determining the Capacity Factor of Wind: A Survey of Methods and Implementation*. Windpower 2005 Conference.
[44] *Id.*

6
OPERATIONAL ISSUES

The Intermittency Issue

The fundamental characteristic of renewable resources like wind and solar that distinguishes them from conventional resources is that they are intermittent. In this context, intermittency is a combination of two factors: variability and predictability. Using wind power as an example, variability refers to the fact that the wind does not always blow at a constant speed, and therefore the quantity of power being produced changes frequently. Predictability, on the other hand, refers to our inability to know the pattern of variability beforehand.

Predictability is important because if we could perfectly predict the quantity of power a wind turbine would produce, and when, there would be no direct system penalty incurred by wind power generation (unless, of course, the variability of the wind exceeded the total underlying flexibility of other generating units in the system). With perfect predictability, the system operator would commit the required other generating resources on the system, and intermittent renewable power would be the functional equivalent of a reduction in load. We do not, however, live in that perfect world.

In practice, the moment-to-moment operation of a power system with high levels of intermittent renewable generation is challenging because the system operator must balance generation and demand while maintaining power quality and low costs without violating system constraints. The additional variability occurs at all timescales, from seconds to hours. This additional variability produced by intermittent resources must be evaluated within the context of the random behavior of consumers that create variations in power demand.

Studies from the United States and Europe have shown that on the time scale of seconds and minutes, the output of intermittent renewables does not significantly change from its prior state, with the exception of during storms and other wind-related events.[45] Thus the prediction error in these time scales is far less than the prediction error in load forecasts. However, as the time scale increases to hours and days, the forecast error can increase to be significantly greater than the load forecast error. When this occurs, costs resulting from additional unit commitment or energy balancing between systems can be expected. Not surprisingly, energy balancing costs are primarily due to forecasting errors.[46]

These issues are magnified in smaller isolated systems. Very often these systems have relatively little in the way of regulating reserves and load-following ramping capability compared with larger, interconnected systems. Therefore, intermittent variation can create frequency deviations in the seconds-to-minutes timescale that can only be addressed by adding regulating reserves. This is done by using either supply-side assets, like storage or diesel generators, or demand-side

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[45] Milligan, M. (2000). *Modeling Utility-Scale Wind Power Plants Part 1: Economics*. National Renewable Energy Laboratory. NREL/TP-500-27514.
[46] E.ON. (2004). Presentation for Meeting with Tohoku Electric Power Co., Inc.

assets, such as responsive load. Longer-range prediction errors create an even greater problem of ensuring that the right units to be committed are available (e.g., not on maintenance), and that the lead-time in committing steam units is factored into the situation.

In general, variability and unpredictability lead to several operational issues that are specific to intermittent resources. These operational considerations include impacts at each time scale, as shown in Figure 6-1.[47]

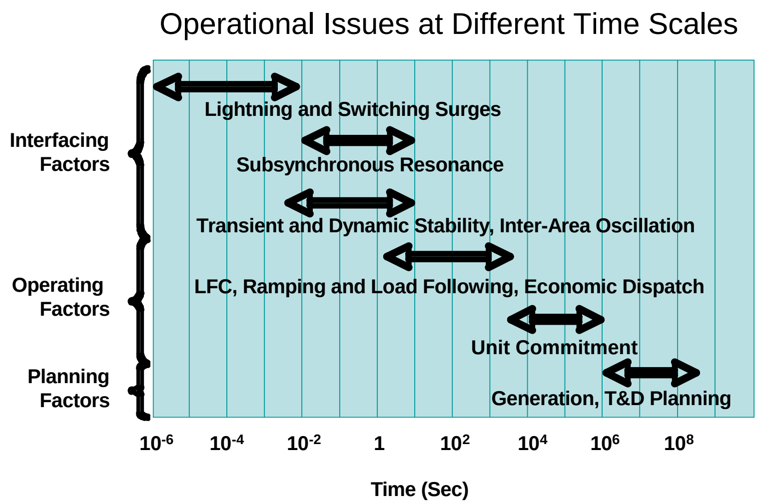

Figure 6-1
Operational Issues at Different Time Scales

Transient stability, or fault ride-through, means that the intermittent resource must be able to continue to operate during and after a fault on the electrical system itself. It can take between a few hundred milliseconds and two seconds to clear the faults. The renewable resources should be equipped with under-voltage ride-through capability for their expected output to avoid either turbine acceleration and over speed, which could damage the equipment. Also, when equipped with under-voltage ride-through capability, the renewable resources can avoid having their generator tripping off line, which can force the utility to either bring on new generation or shed load. This issue is generally addressed by the interconnection requirements of the utility and the equipment upgrades from the renewable generation manufacturers.

[47] Wan, Y. and Parsons, B. (1993). *Factors Relevant to Utility Integration of Intermittent Renewable Technologies*. National Renewable Energy Laboratory.

From a system perspective, the operational considerations of primary concern are those in a time scale of greater than one second. Frequency regulation is the most important operation issue given the increase and decrease of generation output over seconds or minutes. In interconnected systems, the imbalance between load and generation results in energy balancing costs between systems. Conventional generators include governor droop control so that they can decrease power output in the event of an increase in system frequency. Generation output can be increased (ramped up) in the event of a decrease in system frequency. Clearly, intermittent renewable generators, such as river hydro, wind, and photovoltaic power, do not have the ability to change their output as system frequency changes. In fact, their fluctuating output can be the cause of imbalances that push the system frequency outside the control limits.

This issue can be addressed through a combination of two mitigation approaches. The first is for the utility to create limits on the allowable change in output during specified periods for the renewable power plant (typically related to increases in power production). In this instance, excess power would have to be spilled. The second is to provide the adequate reserves on the appropriate time scale to address the problem, and account for the costs of doing so. We address the second approach in this paper.

Different types of reserves are appropriate for different time scales. These types of reserves include:

- **Regulation:** Fluctuations in the seconds-to-minutes time frame are addressed by automated generation control;
- **Load Following/Energy Imbalance:** Variability in the minutes-to-hours time frame is addressed by ramping the capabilities of the generation mix. A combination of spinning reserves, quick-ramping units, and quick-start units are typically used; and
- **Unit Commitment:** Day-ahead commitment of generation units from secondary reserves.

In general, additional reserves will be needed to cover these operational issues when (1) the system would be unable to meet its loss of load probability (LOLP) reliability targets given the variability increase due to the intermittent resource, (2) ramping requirements for intermittent resources exceed system ramping capabilities, or (3) regulation requirements exceed available AGC. The economic implications include not only the direct cost to conventional generators but also the cost of additional operating reserves or storage to address these operational issues. But how significant are these costs in practice?

Most utilities have found that intermittent generation has little impact on regulatory requirements. There are likely several reasons for this. First, with the exception of storms, intermittent output tends to shift gradually as discussed earlier. Second, fluctuation of intermittent power generation within the seconds time frame is within the same range of load fluctuations. As wind penetration increases, however, additional regulation capacity is likely to be required, albeit at a low cost (<$1/MWh).

The impact on load-following resources is based on the combined increase in variability from intermittent output *and* load. That is, what matters is the system variability rather than an independent generator's variability. Recent studies by NREL bear this out. When the combined impact of variability due to wind and demand are evaluated, the overall variance is less than previously estimated by looking at wind alone. Eric Hirst of Oak Ridge National Laboratory describes a methodology for defining the increase in combined variance due to the intermittency of a renewable resource, such as wind.

Forecast error can increase the demand for load-following reserves by requiring increased ramping capability. On the other hand, geographical distribution of intermittent generators can decrease the demand for load-following reserves by capturing any negative resource covariance between geographical locations.

Once the additional variability inherent in, say, wind, is defined, this should be compared against the ramping capability (up and down) of the system during each hour of the year. If the additional ramping requirement is within the system ramping capability, no new generation is required (though there are still operational costs imposed on system). If the ramping requirement exceeds the ramping capability, then additional assets will be needed in order to integrate the wind resources.

Even if no new generation is needed, European studies have found intermittent generators can significantly impact the operation of resources that provide load-following reserves by increasing the number of start-ups for load-following plants.[48] Because start-ups have higher equivalent operating hours than regular generators, as well as higher initial fuel costs, this increases the operations and maintenance costs. Interestingly, the ramping duty of baseload plants increases as intermittent renewable penetration increases because these plants are called on for ramping when the mid-merit plants have been backed down. Again, the fuel and operating costs of this duty cycle are higher than during normal operations.

To compensate for intermittency, load-following resources have higher startup and lower operating efficiencies, particularly when penetration rates exceed 10 percent.[49] However, is the cost of these operating impacts significant enough to dissuade higher penetrations of wind?

In studies around the country, interconnected utilities have found that the cost of these reserves due to the addition of intermittent resources has been relatively low—between $2 and $6 per megawatt-hour (see Table 6-1).[50, 51] While measurable, this cost is equivalent to the cost of including carbon dioxide emissions credits at $8/ton for gas-fired power plans, and far less than the cost of hedging gas volatility.

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[48] ESB National Grid. (2004). *Impact of Wind Power Generation In Ireland On Operation of Conventional Plant.*

[49] *Id.*

[50] Adapted from Smith, J. *et al*. (2004). *Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date*. National Renewable Energy Laboratory. NREL/CP-500-35946.

[51] This low cost could be due to large spinning reserves already maintained on the system and low cost of energy sources (i.e., hydro, nuclear), which do not apply to HELCO.

Table 6-1
Operational Costs on Regulation, Load Following, and Unit Commitment Time Scales

Study	Relative Wind Penetration (%)	Regulation ($/MWh)	Load Following ($/MWh)	Unit Commitment ($/MWh)	Total ($/MWh)
WE Energies II	29	1.02	0.15	1.75	2.92
PacifiCorp	20	0	2.50	3.0	5.50
Great Rivers II	16.6	—	—	—	4.53
BPA	7	0.19	0.28	1.06Š1.80	1.47Š2.27
Great Rivers I	4.3	—	—	—	3.19
WE Energies I	4	1.12	0.09	0.69	1.90
CA RPS Phase I	4	0.17	N/A	N/A	N/A
UWIG/Xcel	3.5	0	0.41	1.44	1.85
Hirst	0.06Š0.12	0.05Š0.30	0.07Š2.80	N/A	N/A

In isolated small-scale systems, the costs are likely to be higher. First, as previously mentioned, there are fewer regulating and ramping reserves available. Hence at higher intermittent renewable penetrations, there is a greater likelihood of additional new capacity being added to address the intermittency problem. This will clearly increase costs when allocated against the renewable power production that caused the problem. Second, an additional operational issue for small, isolated systems is the minimum load requirement for the fossil-fueled steam units. In general, steam units are not entirely turned off during the evening off-peak, but turned down to match the off-peak load. This is done to avoid the high costs of reheating the steam boilers to supercritical temperatures. When intermittent resource generation during off-peak hours rises to the point at which the steam units would need to be turned off, it will generally be more economic to curtail the renewable generation. This action lowers the capacity factor of the renewable generator and can effectively raise its costs by 10 to 15 percent, depending of the degree of curtailment.

It is important to understand the key drivers of operational costs so that one can see how these costs change from region to region and utility to utility. Four primary drivers of operational cost are:

- ***Geographical dispersion of wind power*:** As the geographic spread of wind farms increases, the wind speeds become less correlated, smoothing output fluctuations, and lowering forecast errors by 30 to 50 percent;

- ***Forecasting accuracy of wind power output*:**[52] Unit commitment is typically a day ahead. Hours ahead forecast errors are now very low (<5 to 7 percent). Forecast error for next day ahead averages 10 to 14 percent; advanced algorithms can reduce this to 6 to 8 percent.

- ***Load following capability of generation mix*:** Increasing the mix of load-following units (gas turbines, hydro, storage, etc.) improves the ability of the system to respond to variation in output because these units can compensate better than baseload steam units; and

- ***Interconnection with other grids*:** Interconnection increases the ability to match supply and demand effectively.

Potential strategies to mitigate both variability and unpredictability have been developed. Unpredictability can be best addressed through improvements in persistence, meteorological, and climate-based forecasting models. Variability can be addressed by increasing the mix of quick-start/fast-ramp units in the utility's generation mix, adding electricity storage, or utilizing demand response to compensate for intermittent generation variability. On a very short time-scale (less than one second), variability can be addressed by capacitors or power electronics.

Forecasting Models

Solar and tidal power are fairly straightforward to predict because both the sun and the tides have extremely regular cycles. Solar power output is changed by weather patterns that can be predicted reasonably well. Wind power, however, is much more complex to predict, since winds are driven by many factors. Therefore, this section will focus primarily on forecasting wind power output.

There are three types of wind forecasting models. They are:

- Persistence models: Persistence models set future prediction at the most recent current level; they are typically used for short time-frames (on the order of 15–60 minutes);

- Meteorological models: Meteorological models are physical or statistical models predicting wind based on atmospheric data, from one day to a week ahead; and

- Climate-based models: Climate-based models are statistically-based models predicting wind through the use of climate data, from a week to a year ahead.

These three types of models are based on two techniques:

- Physical models, which use physical considerations to estimate local wind speeds before using model output statistics; and

- Statistical models, which combine all explanatory variables to calculate wind power directly.

[52] While wind forecasting will likely help reduce the operational cost of integrating wind, it is less likely to help with the second-to-second and minute-to-minute fluctuations in wind and maintaining system frequency.

The current most accurate models include both physical and statistical techniques. Meteorological models currently in use around the world include eWind (U.S.), WindLogics (U.S.), Zephyr/WPPT (Denmark), Wind Power Management System (Germany), and Sipreolico (Spain).

Through continued improvement, these models are now reasonably accurate. Persistence modeling is generally accurate for one to three hours ahead, after which more sophisticated techniques, such as meteorological models, are needed. As shown in Figure 6-2, the magnitude of error increases over time. However the error within the entire EoN control zone is smaller than the errors of either the coast or inland zones, highlighting the value of geographical dispersion across different wind regimes.[53]

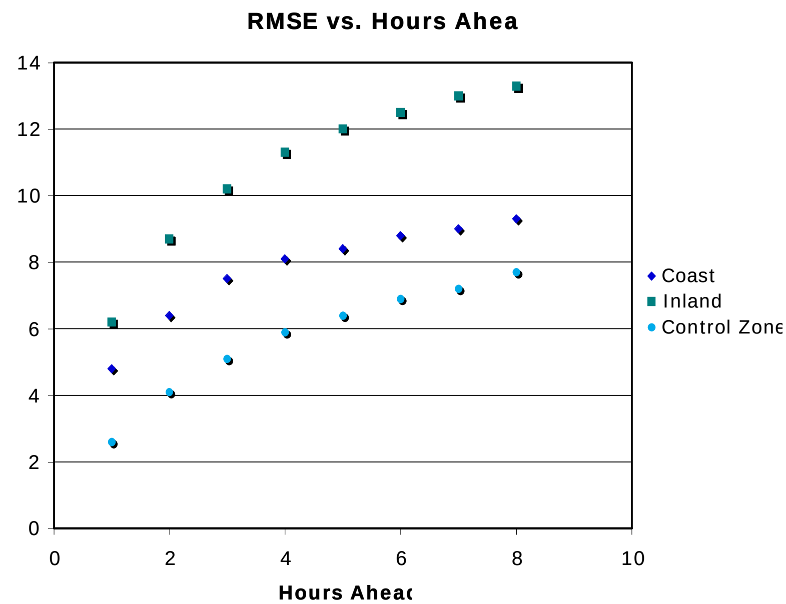

Figure 6-2
Root Mean Square Error versus Forecast Hours Ahead

[53] Rohrig, K. *Online Monitoring and Prediction of Wind Power in German Transmission System Operation Centres*. Institut fur Solare Energieversorgungstechnik e. V.

Meteorological models, typically used for day-ahead forecasting typically have errors of plus or minus 10 percent for 85 percent of forecasts (Figure 6-3).[54]

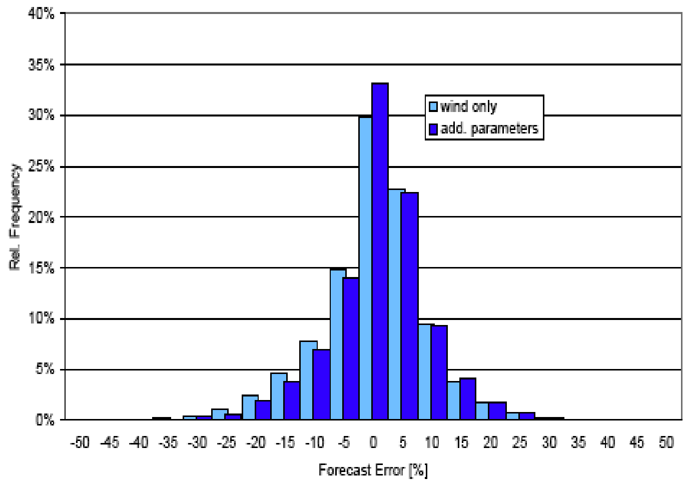

Figure 6-3
Forecast Error Frequency Distribution

Energy Storage

Bulk energy storage technologies represent a range of physical assets that can provide a variety of different storage and output capabilities. These technologies can take several forms, as detailed in Figure 6-4.

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[54] *Id.*

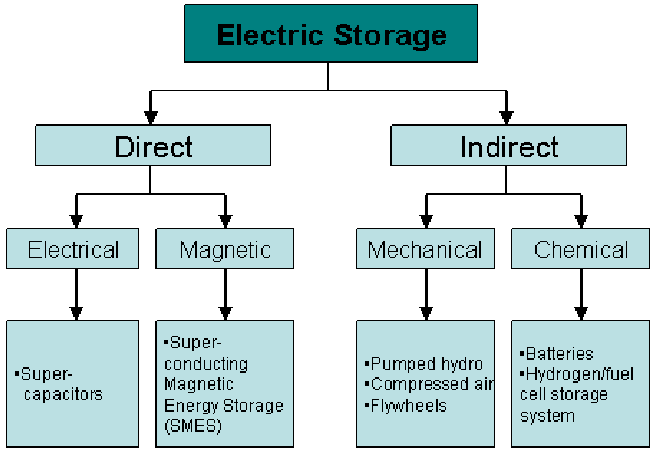

Figure 6-4
Bulk Energy Storage Technologies

The storage services and related requirements that can address the problems created by intermittent renewable power include:

- Regulating reserves: seconds or less;
- Frequency regulation: seconds to minutes;
- Voltage regulation: seconds or less;
- Increase minimum load: minutes and hours;
- Energy shifting: hours; and
- Peak-clipping: minutes and hours.

Different storage technologies are appropriate for different types of storage needs.[55] A combination of storage technologies will often be needed. For example, batteries can provide a full range of storage services, but are especially appropriate for regulating reserves and frequency regulation. However, batteries are quite expensive, often several thousand dollars per kilowatt. Pump storage is far less expensive and is an ideal technology for energy shifting, peak clipping, and increasing minimum load. However, pump storage is unable to provide the rapid response needed for regulating reserves and may not always be suitable for frequency regulation. As a distributed resource, the location of energy storage technology on the grid is particularly important for maximizing its overall value.

[55] Mariyappan, J. *et al.* (2004). GreenNet Interim Meeting presentation. (Brussels).

The potential value of energy storage at the utility scale can be seen in the Bonneville Power Administration's (BPA) hydropower firming service.[56] BPA is using its large hydro resource to absorb the variance of wind power. BPA is offering two distinct services: its Network Wind Integration Service, and its Storage and Shaping Service. Through its Network Wind Integration Service, BPA effectively promises to fully utilize available wind power output and thereby offset output that it otherwise would have been required to provide. BPA recognizes that the reliability of wind generation can be tenuous and therefore holds enough generation capacity to fully back up the wind resources. In this way, BPA ensures that it will always be able to make up any difference between the customer's load and available wind output. BPA charges a $4.50 per MWh fee for all scheduled energy that it integrates into the system. For customers interested in purchasing the power generated by wind resources but unwilling or unable to manage its hour-to-hour variability, BPA provides storage and shaping services. Using the federal hydro system as a storage unit, BPA accepts the hourly output of wind projects and stores this energy over the period of a week. The following week the energy is redistributed to BPA's customers in flat peak and off-peak blocks. These storage and shaping services are being sold for $6 per MWh. In essence, this is what it costs to eliminate the predictability error.

In isolated, smaller-scale systems, energy storage technologies can enable the use of significantly more renewable resources. A recent HELCO study found that 20 MW of battery storage could provide enough regulating reserve to accommodate 30 MW of additional wind on a 150-MW system that already has nearly 12 MW of wind.[57] In other words, adding energy storage equal to 10 percent of system capacity would enable intermittent generation to rise to over 20 percent of system capacity (and total renewables to increase to 35 percent). Thus, for these isolated systems, a combination of intermittent renewables and storage can create the portfolio of assets necessary to displace new fossil-fuel capacity by "firming" the wind power.

"Firming" wind power (or other intermittent resources) with storage can provide a means to address risk preferences regarding fossil fuels (see Figure 6-5). Consider the following example of what it would take to displace 21 MW of conventional fossil-fuel capacity. Let's assume the correlation between the 21-MW wind farm and the utility's peak load would result in a capacity credit of 20 percent using the ELCC method discussed in earlier chapters. However, since this is an isolated system, no capacity can be displaced until the portfolio of wind and storage assets are assembled that would provide the same suite of energy services as electric generation capacity. Thus, we add another 17 MW of pump storage and 2 MW of battery storage to provide regulating energy. If we add up all the costs of the system, we can define the total costs for providing 80 GWh of firmed energy, with an equivalent capacity of 21 MW.

With this combination of assets, we can back down the number of fossil fuel units required—in this case a 21-MW combustion turbine running on fuel oil. We first displace the capital and fixed operating and maintenance costs. What remains are the variable costs, predominantly fuel costs. We reduce the amount of energy displaced during the hours the combustion turbine would have run (roughly a 20 percent capacity factor) using the higher heat rate of 10,970 Btus per kWh, and then displace the remaining energy based on the thermal efficiency of the next unit in the dispatch stack, a combined-cycle unit with a heat rate of 7,890 Btus per kWh. We can now vary the fuel price input until the costs of the displaced fossil-fuel unit precisely equal the costs of the

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[56] Bonneville Power Administration. (2004). *BPA Wind Integration Services*.
[57] Hawaiian Electric Light Company. (2004). *HELCO Operational Issues: Bulk Energy Storage.*

wind-storage hybrid combination. In this example, the fuel costs are the equivalent of $24 per barrel. In other words, the firmed wind system is the equivalent of a 15-year contract on oil at $24 per barrel, a clearly advantageous hedge.

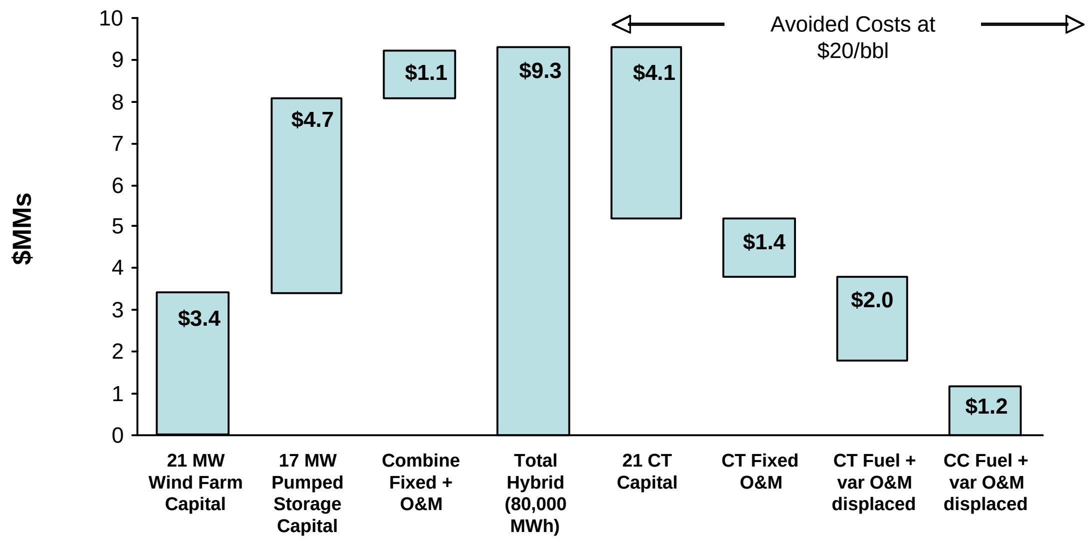

Figure 6-5
Wind Plant Comparison versus Fuel Oil Combustion Turbine Plant

Note: Wind plant: capacity @43%, 20% capacity credit, 14% of output curtailed. Storage @80% of power output, pumped hydro storage costs of $2,435/kW, fixed O&M price of $42.61/kW-yr, and transmission charges of 0.3c/kWh. CT plant: capital cost of $1,612/kW, 20% capacity factor, 10970 BTU/kW heat rate and $66/kW-yr of O&M charges. Mid peak energy at CC heat rate of 7,980 btu/kwh

The same analysis can be conducted for interconnected systems using gas prices. Using the same methodology, but this time buying the regulating energy requirements from the market, and using demand response as a less expensive form of virtual storage, the wind-demand response hybrid can be the equivalent of a 15-year contract for natural gas at a cost of $4/MMBtu (se Figure 6-6).

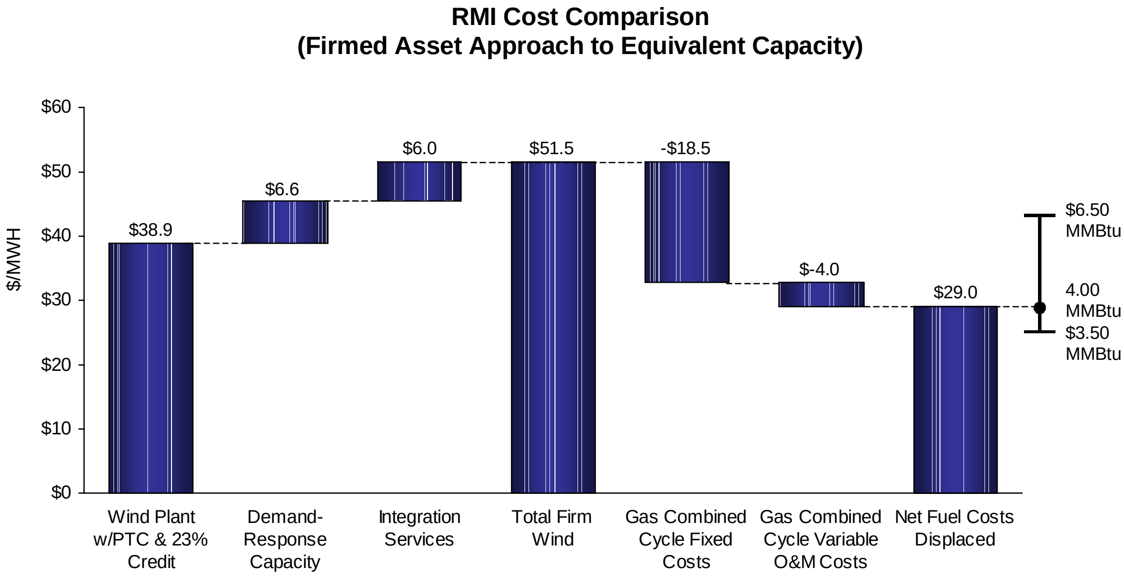

Figure 6-6
Wind Plant Comparison versus Natural Gas Combined-Cycle Plant

Demand Response

Demand response (DR) programs have the potential to serve as "virtual" energy storage.[58] Demand Response programs have typically been used for interrupting loads during system emergencies. However, DR can also be used more frequently to manage intermittent variability without interrupting the service that power provides. These load-flexing programs adapt to building HVAC and lighting systems' schedules without causing building temperatures to rise beyond a certain set point. This type of program produces immediate, measurable reductions in load, and can they can be designed as open-ended programs with customers. The cost of demand response varies considerably with the type of building, the existing equipment, and the required incentives. In general, though, the cost of demand response varies from roughly $30 per kW-year for commercial buildings with energy management systems to about $50 per kW-year for residential air conditioning control.[59] In either case, DR is cheaper than development of a peaking combustion turbine. The implication is that load management should be designed to be a more active part of the approach for total system management.

[58] Kirby, B. (2003). *Spinning Reserve From Responsive Loads*. Oak Ridge National Laboratory. ORNL/TM-2003/19.
[59] Costs based on RMI analysis.

Conclusions

It is clear that the incremental cost of ancillary services attributable to intermittent resources increases with penetration levels, while reliability value (capacity credit) decreases. This is due to the uncertainty and variability in the wind plant output, with the greatest uncertainty in the unit-commitment time frame. Though additional reserve generation may be needed to compensate for wind variation, the amount is far less than an equal amount of dispatchable fossil-fuel generation and modest relative to the size of the wind plant. The cost of required reserves is significantly lower when the combined variations in load and geographically-dispersed wind plant outputs are considered, as opposed to when the variations in a single wind farm are considered alone. Improving the accuracy of wind forecasts will result in lower cost of load-following ramping reserves and unnecessary unit commitment. Additional conventional generation may need to be added as penetration rates increase. Finally, physical and virtual storage can provide technical solutions to these problems, at a cost that may well be justified on many utility systems, particularly if off-peak renewable generation would otherwise be curtailed. The tradeoff between reliability and diversification benefits and added costs must be reconciled through the utility planning process.

7

UNDERSTANDING THE VALUE OF DISTRIBUTED RESOURCES AND GRID BENEFITS

Increased demands on the nation's electrical power systems and incidences of electricity shortages, power quality problems, and electricity price spikes have incited many utilities to seek other sources of high-quality, reliable electricity. Distributed generation resources—that is, small-scale power generation sources located close to electricity demand—provide an alternative to or an enhancement of the traditional electric power grid.

As utilities continue to shift away from long-lead-time, centralized power plants and include more distributed generation assets in their electricity portfolios, it is increasingly important to achieve a thorough understanding of the qualitative and quantitative benefits of these decentralized alternatives. The following two chapters aim to provide an understanding of the economic value created by distributed resources and the methodologies and techniques used to capture this value in the utility system.

How Do Distributed Resources Create Value?

In *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, RMI demonstrated how some 207 typically overlooked benefits can make distributed resources up to five times more valuable than previously thought. These 207 benefits have been consolidated into seven major themes that describe the value that distributed resources offer:

1) **Lower Supply Costs: Generation Capacity and Reserves. "**Distributed generation," or load management, reduces a utility's system peak, thus utilities will have lower capacity requirements including reserve margin adjustment. Further, the total reserve margin required for any given utility system decreases as unit size diminishes.
2) **Lower Supply Costs: Energy.** Distributed generation resources reduce the cost of supply by:
   a. Avoiding energy costs and associated losses;
   b. Demanding elasticity: responding to price signals or system operators during times of peak demand to clip demand and lower power market price and volatility;
   c. Achieving higher thermal efficiencies than centralized generation plants (e.g., combined heat and power);
   d. Shaping load to lower supply portfolio management costs; and
   e. Shifting load to lower-cost energy time periods.
3) **Lower Supply Costs: Grid Value.** Distributed resources can provide substantial cost savings if enough of them are sited where and when they can defer pending investments in utility distribution capacity. Thus, utilities should be able to avoid marginal distribution capacity costs if distributed resources are implemented on a concentrated basis that defers investment.

4) **Ancillary Services Value.** Certain distributed resources can provide a variety of ancillary services if the utility is able to control, measure, and verify their impacts. These include spinning reserves, non-spinning reserves, frequency control, voltage regulation, and reactive power.

5) **Customer Reliability.** By providing an independent power source near the customer load, distributed generation can improve the reliability of electric service to critical customer loads. Premium reliability can have a very high value in such sensitive industries as data management and semiconductor fabrication, as well as many more-conventional businesses.

6) **Risk Management: Planning Flexibility and Option Value.** Small scale, modular resources with short lead times can provide added value by offering the ability to put in place just as much generating capacity as is needed to meet load. The value derived from this increased flexibility is based on shorter lead times and the reduced risk of overbuilding, which reduce financial cost and risk. Because of the potential for staged investment, distributed resources can be a real option to manage the risk from future price spikes or load-growth uncertainty.

7) **System Diversity and Resilience.** The inherent characteristics of distributed resources—close proximity to load, modularity, quick response time—can make disruptions local, brief, and unlikely. In addition, by blunting the effect of deliberate disruptions, distributed resources reduce the motivation to cause such disruptions in the first place. In an increasingly insecure world, this security benefit is becoming increasingly valuable.

Lower Supply Costs: Capacity and Reserve

The process for defining generation capacity requirements and reserve margin for any utility system using central generation units and transmission lines is well understood. The utility industry has less understanding of how to fully value the capacity benefits of distributed resources. This is because distributed generation has two effects: 1) smaller scale units lower the total requirement for reserve margin due to their greater pooled reliability, and 2) any given distributed resource reduces peak demand plus reserve margin.

A distributed resource reduces the demand at the point of consumption, lowering load. This avoids not only the generation to serve it, but also the reserve margin.[60] Therefore, the effective capacity benefit of the distributed resource is not only the generation capacity it provides but also the reserve margin it offsets, or MW x (1 + reserve margin).

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[60] Reserve margin is meant to cope with all sources of uncertainty in the supply/demand balance—severe weather, unusual customer activities, plant outages, transmission faults, or scheduled maintenance.

The size of the reserve margin is not fixed; rather it is a function of the relative size and reliability of its generation units and its interconnections. Thus, the amount of reserve margin required could vary by several fold, depending upon the scale of each unit relative to the whole system, the number of units, and the reliability of each unit. The amount of capacity needed to achieve system reliability decreases with relative unit size and vice versa. Put another way, larger units need more reserve to make up for their potential loss. Unless that loss is so unlikely that the unit's forced outage probability is comparable to the desired system loss-of-load probability, the potential loss of the unit will degrade system reliability, so backup is absolutely required. The only question is how much. In short, when a big generating unit dies, it's like having an elephant die in your living room. You need a second elephant, equally big, to haul the carcass away. Those standby elephants are expensive and eat a lot.

Thus, "larger units impose a more substantial burden of reserve capacity on the system."[61] How much so? The canonical formulation was for decades, and still qualitatively remains, that of the 1958 graph (Figure 7-1), typical of U.S. utility systems and unit reliabilities of that era.[62]

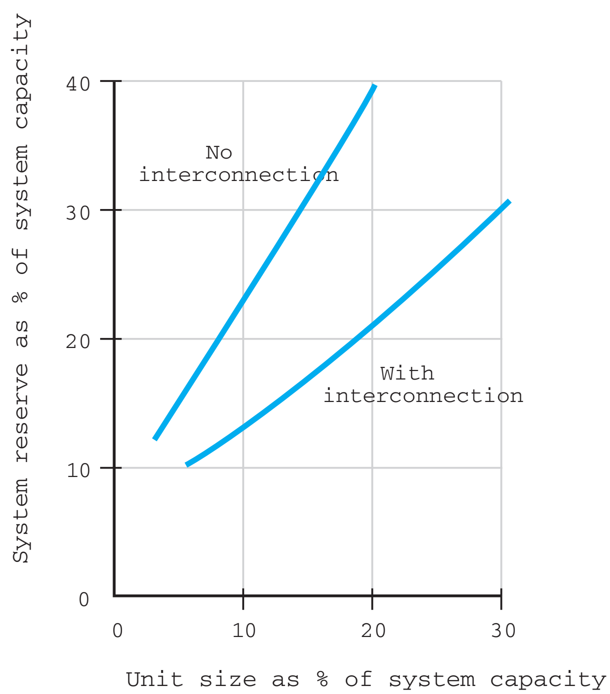

Figure 7-1
1958 Graph of Typical U.S. Utility Systems and Unit Reliabilities of that Era

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[61] Ford, A. and Flaim, T. (1979). *An Economic and Environmental Analysis of Large and Small Electric Power Stations in the Rocky Mountain West.* Los Alamos National Laboratory.
[62] Galloway C.D. and Kirchmayer, LK. (1958). *Comment*. Transactions of the American Institute of Electrical Engineers 39:1142-1144, fig. 4-3. Cited in Ford, A. and Flaim, T. (1979). *An Economic and Environmental Analysis of Large and Small electric Power Stations in the Rocky Mountain West.* Los Alamos National Laboratory.

To achieve the same *reliably available* supply, small units permit a given amount of large-plant capacity to be replaced by a smaller amount of small-unit capacity because multiple small units are far less likely to fail simultaneously than a single large unit. Therefore, less of the installed capacity is likely to be unavailable when needed. Why? The uncertainty of the output decreases with the number of units due to their independent failure rates and the central limit theorem of statistics. In essence, since each unit's likelihood of failure is independent of other units' failure rates, and each distributed generation unit has a bionomial failure rate, the sum of those units is subject to the central limit theorem (see Figure 7-2).

This has a number of ramifications. First, a large number of distributed generators will have an approximately normal distribution of output. Second, the standard deviation of the output will decrease significantly (by the square root of N). Third, the relative risk, which is the ratio of standard deviation to mean, will decrease with increasing n. As explained in more detail in the following chapter, at a threshold level of 50 plants, the output is smoothed considerably.

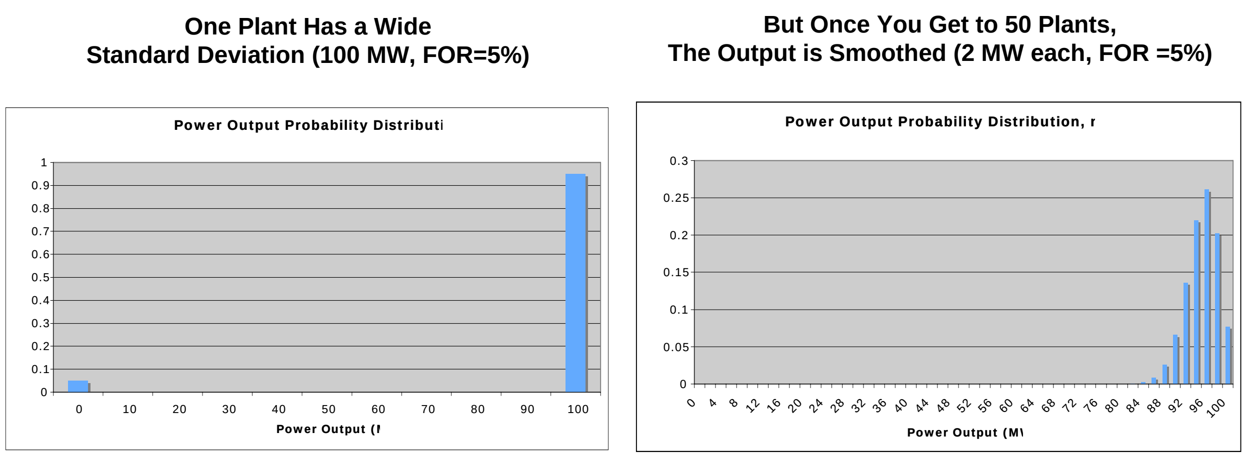

Figure 7-2
Deviation of One Plant versus Fifty

The question then arises as to whether smaller distributed units are less reliable then their central generation counterparts. By taking into account the availability and the forced outage rate of distributed generation units relative to larger generation units, this question can be answered. While national-scale data is available from manufacturers, local operational data of customer-owned distributed generation must be collected by the local utility.

While the actual availability of distributed generation resources is equipment-specific, high technical availability is an inherent per-unit attribute of many distributed generation systems. Distributed generators tend to endure less extreme technical conditions (temperature, pressure, chemistry, etc.) than large plants, so they tend not to incur the inherent reliability problems of more exotic materials pushed closer to their limits. In addition, distributed resources such as photovoltaics and end-use efficiency can have a further availability advantage—few and generally brief scheduled or forced maintenance intervals.

For comparison, all U.S. fossil-fueled power stations of all sizes during 1989–93 averaged only 85 percent available (those in the GW range did worse)[63]; nuclear, 73 percent; gas-turbine, 90 percent; combined-cycle, 88 percent; and even hydropower, 91 percent.[64]

It is worth noting that the benefits of smaller scale outweigh concerns over lower mechanical reliability. For example, even if distributed generation had a 2 percent greater forced-outage rate, smaller units would require substantially less capacity (for example, 24 distributed units would require 10 percent less capacity than 12 centralized units (see Figure 7-3). Thus, on isolated grid systems, even if distributed generation has higher forced-outage rates, the required capacity may be lower. As a utility seeks to meet new load growth, smaller utility-dispatched distributed generation can provide more reliability for less capacity.

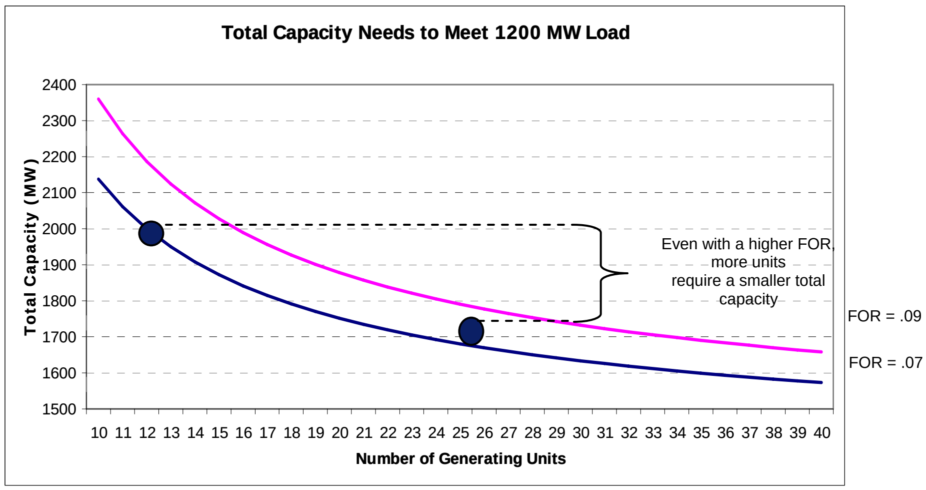

Figure 7-3
Total Capacity Needs to Meet 1200 MW Load

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[63] Not corrected for annual or seasonal deratings, but those equivalent availabilities are even worse, by about three percentage points for the steam plants, five for gas turbines, and seven for combined-cycle.
[64] North American Electric Reliability Council. (1995). *Generating Availability Report 1990–1994*. www.nerc.com/~filez/gar.html.

Lower Supply Costs: Energy

Displaced Energy Cost and Losses

Obviously, distributed resources avoid the variable costs of producing energy during the hours that the distributed resource is either producing or, in the case of efficiency and demand response, avoiding having to produce the energy at all. Since the energy savings occur at the point of end use, grid losses are also avoided. It is important to note that average grid losses understate the value of distributed resources. Peak grid losses (10–14 percent) are typically double system average grid losses (typically 4–7 percent). Therefore, the correct calculation of avoided energy costs includes both the marginal cost of energy and marginal system energy losses for each hour that the distributed resource produces or avoids energy production, not just the average.

Distributed resources reduce grid losses in four main ways:

- Shorter haul length from the more localized (less remote) source to the load, hence less resistivity, or electrical resistance per unit of cross-sectional area and length;
- Lower current if the resource is end-use efficiency or local generation that reduces required net inflow from the grid, hence less carried current;
- Effective increases in conductor cross-section per unit of current if an unchanged conductor is carrying less current, hence less resistivity; and
- Less conductor and transformer heating if current is reduced by more efficient use, by load management or peak-shaving that reduce on peak coincidence, by better management of existing transmission assets, or by better distribution circuit management that better shares loads among parallel distribution capacity.

The actual losses that distributed resources can avoid are quite complex, and depend not only on the grid load displaced but also on the time, weather, load conditions, load shapes, and—especially—physical placement in the grid.

Achieving Economic Dispatch

In many utility systems, must-run units are often located within urban centers due to the need for reactive power and the constraints in transmission lines' ability to deliver power from more remote central generation. Often, these units are out-of-merit-order plants, and, therefore, are more expensive to run. To the extent that infusing distributed generation—by delivering power when and where it's needed—can help to displace must-run units, this will significantly reduce the system's total operating cost.

Further, because the marginal costs of new generation technologies, particularly gas-fired turbine generators and distributed resources, continue to fall, new market entrants have the means to undercut many utilities' average costs of generating electricity, particularly when grid costs are included. For example, in the case of island-scale systems, 1 MW combined of heat and power might cost much less than 10–50 MW of conventional generation due to improved thermal efficiency of cogeneration and tri-generation. This is especially true when energy prices are high, where the annual energy cost savings outweigh the difference in annualized capital costs.

Demand Elasticity

On the demand side, a revolutionary change is occurring within power markets as customers are beginning to realize the value of managing their loads and harnessing distributed generation. The summer of 2001 was extraordinary because of the lack of blackouts or lofty peaks in power prices, even in such tight markets as California and New York City. As customers responded to higher prices and poor reliability, their own end-use efficiency, load management, and distributed generation added 50 percent more available power in both these markets than new central generation capacity added during 2000–01.[65, 66]

That trend comes from the buyer's ability to change the market price by harnessing the underlying option embedded in distributed resources and dispatching it into the market. The option inherent in end-user load is not simple interruption, since this can be used only infrequently (generally fewer than four times per month using 4-hour windows). Rather, it is the ability of commercial and industrial customers to flex their net demand using distributed resources— both demand- and supply-side—in response to price signals or payments, coupled with their willingness to allow a third party to dispatch their negawatts or distributed kilowatts. The impact of changing the market price can be dramatic due to the very high degree of supplier price elasticity in the bidding process. Our research shows that if an additional 500 MW of energy from dispatchable distributed resources had been available to California's default buyers in 2000, consumers would have saved $1 billion.[67]

Cogeneration and Increased Thermal Efficiency

Power plant engineers have devoted immense ingenuity to trying to increase the amount of electricity derived from each unit of fuel. Unfortunately, improvements in thermal efficiency collided with practical limits around 1960 when the electrical capacity per unit of classical steam plants reached about 400 MW. As shown in Figure 7-4, average thermal efficiencies improved to about 34 percent during the 1960s; however, the average efficiency of U.S. power plants has slightly decreased since that time.

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[65] California Energy Commission, and Keese, W. (2000). *Supplemental Recommendation Regarding Distributed Generation Interconnection Rules*. Docket no. 99- dist-gen (2); CPUC docket no. R. 99-10-025.
[66] Lovins, A. (1998). *Negawatts for Fabs: Advanced Energy Productivity for Fun and Profit*. RMI Pub. E98-3. Snowmass, CO: RMI. www.rmi.org/sitepages/pid171.asp.
[67] Barnes, P., Dyke, J. Van Tesche, F. and Zaininger, H. (1994). *The Integration of Renewable Energy Sources into Electric Power Distribution Systems. Volume I: National Assessment*. 6775. Oak Ridge, TN: ORNL Oak Ridge National laboratory.

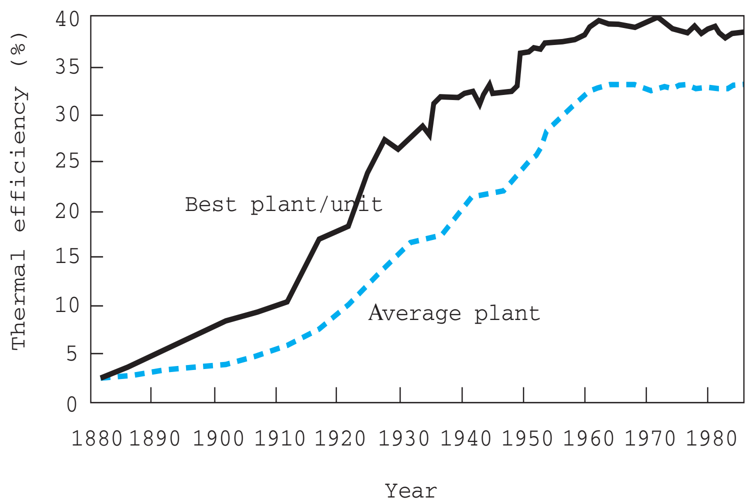

Figure 7-4
Thermal Efficiency of U.S. Steam Plants Saturated Around 1960[68]

Combined heat and power (CHP) technologies can offer dramatically better thermal efficiency. A wide variety of CHP technologies generate electricity and meet thermal energy needs (direct heat, hot water, steam, process-heating and/or cooling) simultaneously, at the point of use. While conventional electricity generation discards much of the heat generated during energy production, CHP makes greater use of fuel inputs by utilizing discarded heat and producing system efficiencies that can range from 60 to 80 percent.

Tri-generation, which adds adsorption chilling to displace air conditioning loads, has even greater whole-system thermal efficiency. Tri-generation units often have total thermal efficiencies approaching 90 percent. Further, they displace increasingly inefficient central generation units. Since air conditioning loads are almost always coincident with the peak and power plants used to serve peak loads tend to be inefficient combustion turbine or diesel units (15–20 percent thermal efficiency), the efficiency benefits and total system economics of tri-generation are very favorable.

Combined heat and power units are typically customer-owned, and used to displace their own energy requirements. Systems that are sized-based on the thermal loads may generate excess power that can then be sold into the grid. These systems can then be dispatched in merit order, and will typically be dispatched before combined-cycle units.

To the extent that regulators allow cogeneration to be operated by a utility, the full spectrum of distributed benefits discussed in this chapter is more likely to be realized. Utility operation allows the utility to dispatch any excess generation capability just like any other generation unit. Hence the full energy, capacity, grid-side, and ancillary service benefits will also be available. Utilities may also have more resources for operations and maintenance, which can increase mechanical availability. Often the planned maintenance schedules will be synchronized with the

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[68] Hirsh, R. (1989). *Technology and Transformation in the American Electric Industry.* Cambridge University Press.

rest of the generation fleet, ensuring maximum available capacity during peak periods. These benefits can also be achieved without utility ownership through contracting methods. It is worth noting that while utility operation increases the likelihood of receiving all the benefits that distributed resources offer, utility ownership without operation has no incremental benefit (or cost).

Load Shaping

For any type of load, future demand is not fate but choice, and can be chosen with great flexibility by using a balanced portfolio of demand- and supply-side resources. Careful investment in end-use efficiency, load management, and electric-thermal integration (such as cogeneration or thermal storage) can alter the size and timing of demand from almost any load over a very wide range in order to achieve the desired service quality at least cost. It can generally turn load growth into load stability or shrinkage, at any desired time or overall, for any customer or class of customers, on any desired geographic scale, if that is the cheapest way to meet customers' needs.

As one travels from the biggest power stations and transmission lines out through the ever-finer branches of the distribution system, costs rise steeply. This means that the costliest (and the highest-electrical-loss and worst-power-factor) part of the power system inherently suffers from the lowest load diversity and the worst load factors (i.e., the lowest capacity utilization). But the customer end of the distribution system is precisely where distributed resources are often easiest to install and can create the greatest value.

Small units obviously allow greater flexibility in matching supply with demand, both system-wide and locally—the more fine-grained and localized the resources, the better the match. Demand-side resources, the most tailored and local kind, specifically decouple a particular customer's service delivery from electric load shape (by providing the same service with less electricity or with electricity in a different time pattern). They can be complemented by distributed supply-side resources on the scale that will best harness load diversity so as to share capacity among multiple customers' or users' needs, so as to take advantage of not everyone's wanting to do the same thing at the same time.

Lower Supply Costs: Grid Value

Distribution assets typically have very low utilization for an obvious but often overlooked reason: the smaller the area served, the less load diversity available. A single household has a very low load factor because the capacity to serve it must be sized for a peak load that is very seldom experienced, and the average load can easily be ten or tens of times smaller than that peak. The result: utility capacity that can easily be utilized to only 20–30 percent of its full year-round capacity.

The resulting potential for improved utilization of distributed assets is illustrated by the following, increasingly-detailed graphs, made by PG&E in the early 1990s (Figure 7-5, Figure 7-6, and Figure 7-7). These load-duration curves compare typical distribution feeders, and reveal much exploitable scatter between different segments of the 2,979-feeder "fleet."

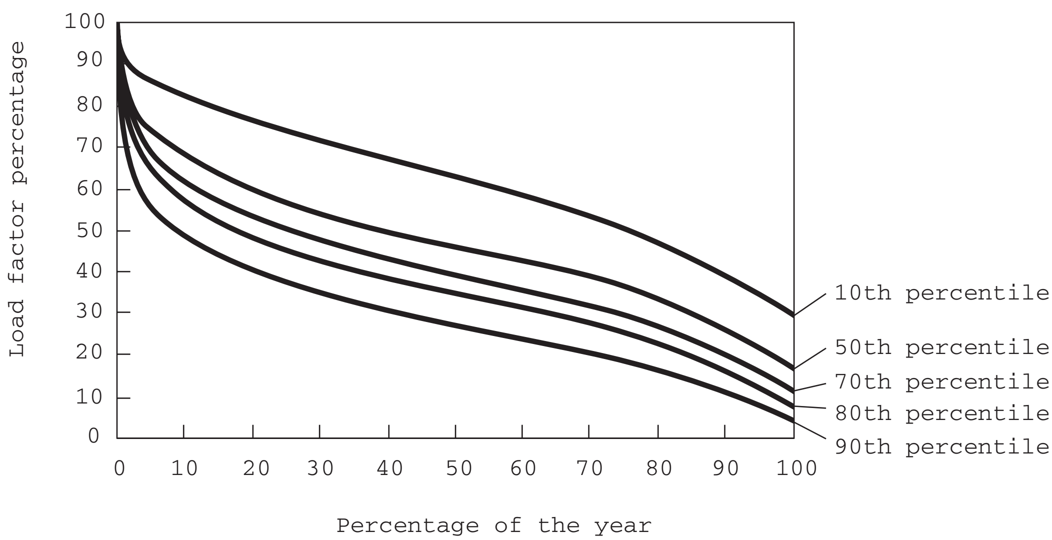

Figure 7-5
Asset Utilization Varies Widely Among Feeders[69]

Such analysis is especially revealing for the feeders at the top (most peaky) 10 percent of the system load-duration curve (Figure 7-6).

[69] Iannucci, J. (1992). *The Distributed Utility: One view of the Future*. Distributed Utility—Is This the Future? EPRI, PG&E, and NREL conference.

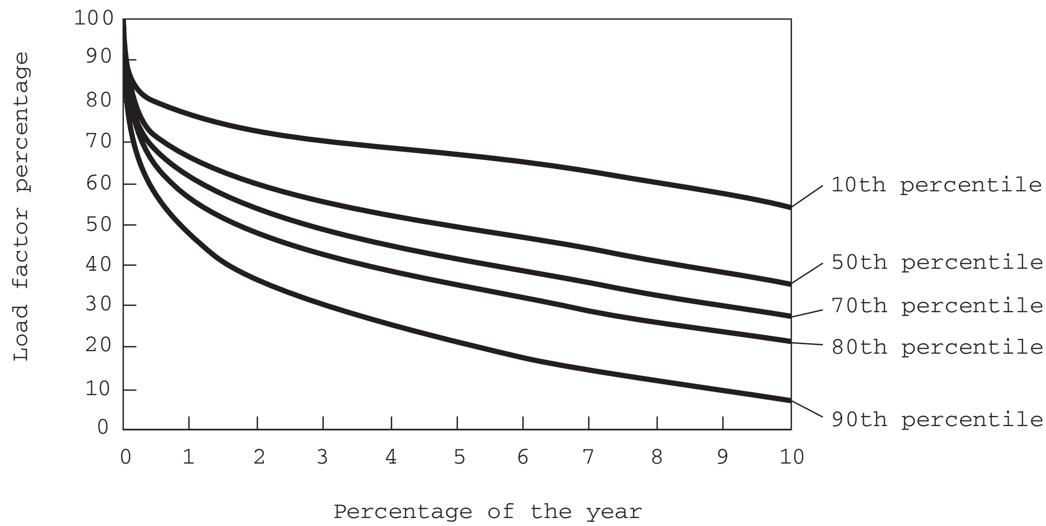

Figure 7-6
Differing Feeder Asset Utilization is Exacerbated Near Peak-Load Hours[70]

Thus distributed supply- or demand-side (or grid-improvement) resources applied at the level where the load factor is worst can most improve distribution asset utilization and can best avoid costly distribution investments. It is precisely at the end of the system that distributed resources are typically installed—just where they will serve the peakiest loads and hence save the biggest distribution costs and losses. Understanding which parts of the distribution system are least utilized can reveal where distributed resources are most lucrative to install.

[70] *Id.*

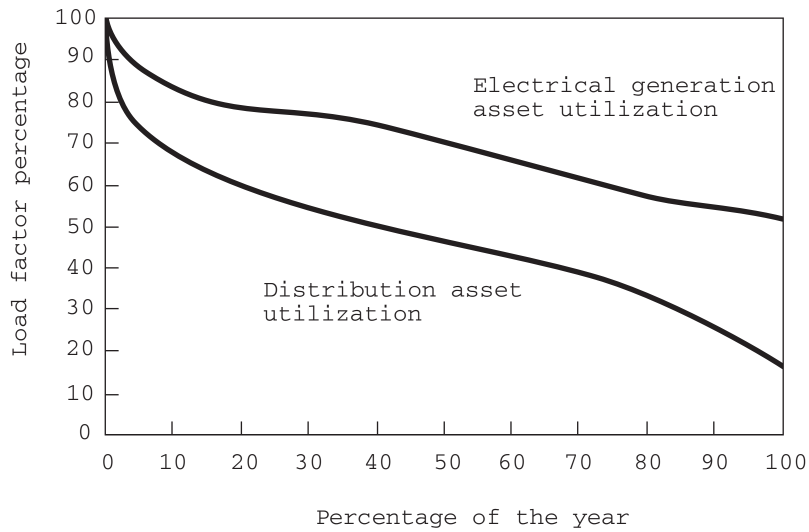

Figure 7-7
Distribution Assets Stand Idle More than Generation Assets[71]

PG&E, for example, found the disquieting pattern shown in Figure 7-7: a *typical* distribution circuit is used at under 50 percent capacity more than 60 percent of the time and reaches 70 percent utilization less than 10 percent of the time—whereas the company's average generating asset utilization *never* falls below 50 percent. The difference in asset utilization expresses the difference in load diversity between a huge utility and a particular, local, fine-grained service area that has fewer customers doing a smaller variety of things that are more likely to need electricity at similar times.

Moreover, PG&E found that locally-specific studies often disclosed enormous disparities: marginal transmission and distribution capacity costs across the company's sprawling system (most of Northern California) were found to vary from $0 to $1,173/kW, and to average $230/kW.[72] The maximum cost of new grid capacity was thus five times its average cost. Since marginal energy and power supplied to customers in these different areas would yield more or less identical revenues (even with more transparent pricing) but would incur such gigantic differences in delivery cost, demand-side interventions carefully targeted on avoiding the costliest capacity additions could disproportionately raise profits.

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[71] *Id.*
[72] However, this may be low. According to Shugar's *Benefits of Distributed Generation in PG&E's Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation*, cites a system average cost of $282/kW for PG&E's transmission alone.

These area- and time-specific (ATS) costs can vary widely in time and space, creating important variations. They allow precise targeting of distributed resources in areas where the distribution utility costs are relatively high. This is further illustrated by data from a study of four U.S. utilities, in four different states, with a total of 378 utility planning areas.[73] These utilities were quite diverse in customer mix, load profile, and size. Their differences in marginal distribution capacity cost (MDCC) were dramatic: marginal distribution costs vary across the system, and can range from $0 (where the system has substantial excess capacity) to $1200/kW, in cases where the system needs significant upgrades, but may face a slowly growing load (see Figure 7-8 below for utility examples).

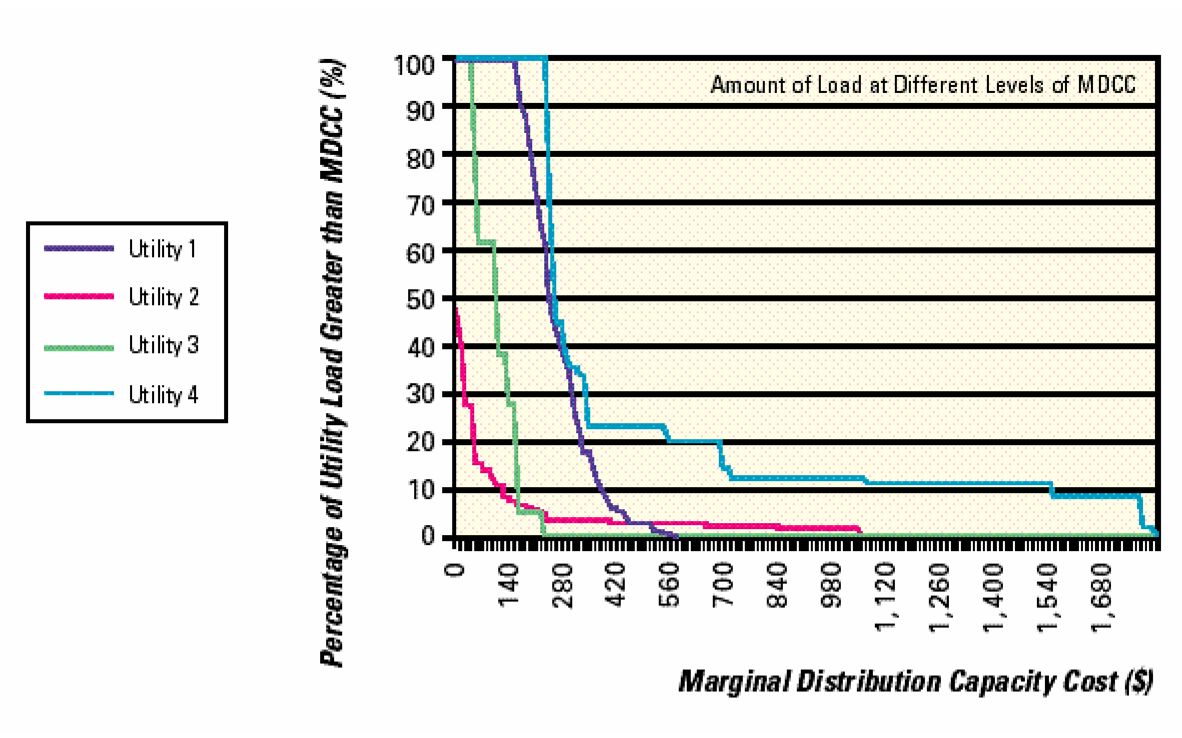

Figure 7-8
Range of Marginal Distribution Capacity Cost for Four U.S. Utilities, 1994[74]

Sound planning to maximize the benefits of distributed resources thus requires utility-specific and fairly up-to-date information, differentiated by time of use and by location. It is encouraging, however, that three of these four utilities, despite their wide variations, showed considerable opportunities worth at least $200–400/kW for deferred distribution capacity. Moreover, distributed resources need not meet an area's entire load to defer planned distribution capacity because the needs are typically spotty. In fact, deferring distribution capacity in *all* high-cost

[73] Heffner, G., Woo, C., Horii, B., and Lloyd-Zannetti, D. (1998). Variations in Time-and Area-Specific Marginal Capacity Costs of Electricity Distribution. *IEEE Transactions on Power Systems.* 13:560-565.
[74] Swisher, J. (2002). *Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Energy Resources*. Rocky Mountain Institute. www.rmi.org/sitepages/pid171.php.

areas shown in the previous graph would require distributed resources equivalent to less than one-tenth of the total existing load, yielding big benefits from modest investments.

It is also noteworthy that since local peak demand drives the MDCC value, that a peak may occur at different times, and it may be caused by customers or loads that are not contributing to the system peak. Thus, if the system peak occurs in the late afternoon, a local area's peak might actually occur at midday and thus the local area might be suitable for, say, photovoltaics whose output does not coincide with the system peak.

Siting and using distributed resources in the places where and during the seasons and times of day when they will yield the greatest value is clearly advantageous. But these optimal sites and times will gradually change as the distribution system and its loads evolve, turning the optima into moving targets. Fortunately, many distributed resources can move too: they are portable, preserving their flexibility to remain in the right place at the right time as system needs change.

Such a fine-grained understanding of opportunities in specific utility systems is a rare-but-important business asset. Its value far outweighs the cost of collecting such time- and area-specific load data—data that can become almost automatically available to the distribution utility (and, one hopes, to its decentralized competitors) as a by-product of distribution automation. Capitalizing on those local data could lead utilities to business strategies that successfully bypass the emerging wholesale bulk-power market with demand-side and grid-based resources "that aren't competitively bid because they don't flow through the grid at all: they are *already* at the load center."[75]

Ancillary Services: Which Ancillary Services Can Each Type of Distributed Generation Provide?

In addition to capacity deferral value, distributed generation can provide economic benefits to distribution utilities by reducing costs in the operation and maintenance of transmission and distribution systems. Ancillary services refer to the ability of the power system to deliver energy in a usable form after it has been produced by generators. These services were previously bundled in the energy and capacity prices, but are now separately purchased in some markets by the Independent System Operator (ISO) in order to meet the reliability needs of the bulk energy system. Certain distributed resources can provide a variety of ancillary services if the utility is able to control them, and measure and verify their impacts. These potential electrical engineering benefits include:

1. **Operating Reserve: Spinning Reserve Service**

   Distributed resources can provide additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur. Distributed substitutes for traditional spinning reserve capacity can reduce its operating hours—hence the mechanical wear, thermal stress, corrosion, and other gradual processes that shorten the life of expensive, slow-to-build, and hard-to-repair central generating equipment.

[75] Lovins, A. (1993). Spotlight on Direct Access: Perspectives on DR Planning Under Competition. *DR Connection*, EPRI (November): 3.

2. Operating Reserve: Supplemental Reserve Service

Distributed generators can provide additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes.

3. Reactive Supply and Voltage Control From Generating Sources Service

Distributed resources can help balance reactive power flows on a distribution system with both real and reactive power injection. Real power injection reduces current in the conductors, which is a major source of reactive power demand that is typically treated with banks of capacitors. Improved reactive power flow (as indicated by a higher power factor) reduces current and loss on transmission and distribution components, and helps control system voltage.

In addition, distributed generation can support voltage in areas of the distribution system that suffer large drops at high loads, replacing voltage regulators and line upgrades. Voltage support is provided by injecting power into the system at the DG site, thereby reducing the current and corresponding voltage drop from the substation to the area. DG can also regulate voltage by balancing fluctuating loads with generation output.

As a result, transformer tapchangers that change output voltage need to be activated less frequently, which reduces wear and tear. One study[76] found that a 500-kWAC PV generator on a feeder could extend the normal rated life of the substation transformer's top-mounted tapchanger from 20,000 tapchanges over 5 years to 20,000 tapchanges over 20 years, while increasing the interval between service calls from 5 to 7 years.[77, 78] The present value of that deferred maintenance is worth $10 per kW-year of substation-level PV output,[79] a significant increase in value just from deferred substation maintenance. It compares, for example, with $47 per kW-year for avoided transmission capacity (in a case with no reconductoring deferral opportunities).

4. Energy Imbalance Service

Distributed resources provide energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served.[80]

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[76] Shugar, D., Orans, R., Jones, A., El-Gassier, M., and Suchard, A. (1992). Benefits of Distributed Generation in PG&E's Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation. PG&E.
[77] *Id.*
[78] *Id.*
[79] *Id.*
[80] Energy imbalance service does not apply in Hawaii due to the lack of interconnection.

5. **Regulation and Frequency Response Service**

Distributed generators enhance following the moment-to-moment variations in the demand or supply in a Control Area and maintaining scheduled interconnection frequency or the frequency within a utility system. Frequency control requires very rapid response, often on the order of cycles or seconds. There are several distributed generation technologies, such as batteries, flywheels, and fuel cells, which can provide regulation energy. “Negawatts” (watts not needed or used) can also provide frequency response. Automated load response, with two-way instantaneous measurement and verification, can reduce load in the same time scale as generation, and thereby also be used to maintain frequency within the control limits.

The Federal Electricity Regulatory Commission (FERC) has altered its rules to expand the definition of which distributed resources can provide ancillary services. While the different Regional Transmission Organizations (RTOs) and ISOs are still defining the rules that allow distributed resources to provide ancillary services, the regulatory trend very clearly supports the inclusion of these resources (see Table 7-1 and Table 7-2).

Table 7-1
Distributed Resources Suitability for Providing Ancillary Services

Ancillary Services	Distributed Generation	Demand Response
Spinning Reserve	Yes	Yes, NERC no longer requires spinning reserves to come from generation.
Supplemental Reserve	Yes	Yes, NERC no longer requires spinning reserves to come from generation.
Reactive Supply and Voltage Control	Yes for dispatch capable DG VAR support, can only be supplied by generators with some type of rotating machine or leading power factor device. No for PV.	No
Energy Imbalance	Yes for dispatch capable DG No for PV	Technical yes, but unlikely energy imbalance is an almost constant service.
Regulation & Frequency Response	Yes for dispatch capable DG	Yes with automatic load control

Table 7-2
Current Rules Governing Distributed Resources (as of 2005)

IPO System	Rules Governing DR Participation
NYSO	Responsive loads may provide 10 and 30 minutes spinning reserves. Load resources that supply 10 minutes reserves must be able to sustain the response for 30 minutes
PJM	PJM requires responsive load used for reserves to sustain the response for 4 hours
ISO-NE	Developing an ancillary services pilot program for summer 2005 to allow DG and DR to contribute to ancillary services

Customer Reliability Benefits

One of the most exciting prospects for distributed generation technology is the potential to provide valuable benefits in terms of improved customer reliability. It is widely acknowledged that with the emergence of the digital economy there is a tremendous need for premium-reliability power in facilities operated by a wide range of businesses. A customer's cost for a power outage, and thus the value of preventing the outage, is clearly increasing. The outstanding questions are then:

- How much is premium-reliability power worth?
- Which customers are willing to pay for premium-reliability power?
- To what extent can distributed generation provide the needed reliability?
- How can the reliability benefits be captured for the distributed generation owner?

The value of customer reliability, which reflects the avoided cost of power outages, is difficult to estimate and appears to be changing rapidly. Distributed generation-provided reliability can reduce inconvenience, discomfort, direct costs, and opportunity costs from lost sales or production. The sum of these is called the value of service (VOS). Value of service estimates vary widely, from low values for residential customers to more than $1,000 per outage, even momentary, for commercial customers. Home offices probably have much higher VOS values than other residential customers, and this market segment is growing as broadband service permeates the residential market.

The most existing VOS studies are still based on surveys of traditional industries, where sustained loss of refrigeration or prime movers could incur substantial costs. Today, however, even the briefest outage could be crippling to many digital-economy businesses. The rapid pace of technological change and the new business models evolving in the information and telecommunications industries make these customer reliability benefits the most difficult distributed generation benefits to quantify at present.

Anecdotal data indicate that many customers believe that brief interruptions can cost them between $40,000 and $200,000, and some manufacturers, such as pharmaceutical and semiconductor companies, consider their outage costs to be on the order of millions of dollars per hour.[81] Internet-based businesses require extremely high levels of reliability, which may reflect VOS values that are orders of magnitude higher. In some cases such values are backed by contractual terms and insurance policies.[82]

Consider the following question: to what extent can distributed generation enhance reliability, and why have utilities not taken advantage of this resource in the past? The answer depends, to a large degree, on how reliability is defined. Utility grid design focuses on providing a uniform level of reliability under conditions of peak demand. Traditional generation system design aims for an outage probability of 0.0003, or 99.97 percent reliability (3.5 "nines"). This level is achieved, despite the 90–95 percent reliability of generation plants, by having excess reserve capacity available.

Because the majority of outages are caused by faults in the distribution system as a result of interference by trees, animals, cars, etc., rather than by generation, the true reliability is about 99.9 percent (3 "nines").[83] Even at this level, it is difficult for a distributed generation system to improve peak availability beyond that of a wires-only system. To do so, the distributed generation capacity would have to serve the entire peak load at a high level of reliability. However, if most of the reliability value is associated with lower loads, and in particular with specific, critical loads, then distributed generation can improve reliability beyond that of a wires-only solution by reducing the probability of losing critical loads. For these loads, distributed generation can increase the reliability to more than five "nines" or more with additional redundancy. Thus, such distributed generation sources as fuel cells can provide customer reliability services that wires alone cannot. Distributed generation can provide protection of critical loads from sustained outages far beyond what a typical uninterruptible power supply (UPS) can provide, and it can respond to problems caused by momentary interruptions faster than can conventional standby generators.

Another important, though subtle, benefit is that once a fault does occur in the grid, appropriately-sited distributed resources can substantially increase the distribution system operator's flexibility in rerouting power to isolate and bypass distribution faults and to maintain service to more customers while repairing those faults.[84] That increased delivery flexibility reduces both the number of interrupted customers and the duration of their outage.

[81] E SOURCE. (1988). *Distributed Generation: A Tool for Power Reliability and Quality*. Report DE-5. www.esource.com.
[82] For example, Sure Power is selling 1-MW grid-independent power supply systems for critical loads, based on the ONSI fuel cell technology and flywheel storage. Sure Power contractually guarantees 99.9999% (six nines) reliability, which is backed by a $5 million insurance policy. With expensive technology and extreme redundancy, this product is clearly aimed at a premium-price market niche.
[83] Almost all distribution failures originate from overhead lines and cables rather than from fixed equipment. In the United States most outages (by some estimates as high as 99%) arise in the grid, and around 90% to more than 95% of those stem from distribution failures, chiefly weather-related.
[84] This benefit would essentially require distributed generation that can island. Configuring distributed generation to island requires special design and protection schemes.

Risk Management: The Value of Planning Flexibility and Options

A fundamental planning risk is the over- or under-building of generation and grid resources. The utility planning process often treats load growth as a series of scenarios, which are a deterministic set of outcomes that ignore probabilities—and hence do not allow for the quantitative evaluation of risk management. Load growth is better understood as a probabilistic function (i.e., " an x percent probability that load will be equal to or less than y MW in z years"). Under this formulation, there is a risk that load could be higher or lower than the projected amount, and therefore that too many or too few resources will be available. The further out we have to project, the more likely we are to be wrong.

Naturally, if just the right number of resources were available when needed, the total system costs would be optimized. Long-lead-time resources mean the decision to add new resources must be made well in advance of when actual load growth is expected with greater certainty. This introduces the risk of overbuilding, which means additional costs to ratepayers.

Further, central power plants are becoming harder to site, which increases the uncertainty regarding their lead-time. This raises the risk of under-building, which lowers system reliability and power quality, imposing even greater costs on ratepayers.

To reduce the financial risks of long-lead-time centralized resources, it is logistically feasible to add modular, short-lead-time distributed resources that add up to significant new capacity. How can utilities value the economic benefits of those smaller resources whose virtue is being faster to plan and build and get operational?

Distributed Generation vs. Central Resources

When central power generation costs were an order of magnitude less than small generation, there was no reason to consider distributed generation (DG) if a connection to the grid was available. Today, however, new technology has brought the cost of DG within the range of that of central generation, even as the cost of central combined-cycle generation has fallen. With DG costs approaching the competitive range, it makes sense to explore the economic benefits of small scale and high flexibility.

Because electricity is prohibitively expensive to store in large quantities, it is like a commodity with a short shelf life, such as milk. Imagine if one could only buy milk in 100-gallon barrels, and that it took several days for an order to arrive. We would no doubt be sure to order earlier than necessary to avoid running out; we would often have an excess of milk; and a lot of milk would be unused and spoiled because of its short life. Wouldn't it be more efficient to get milk in 1-gallon bottles at a local store? We would save so much from reduced spoilage that we could afford to pay a higher unit price for the milk. This premium, based on the option to buy as little or as much as we need, just when we need it, is the "option value" that comes from small size and flexibility.

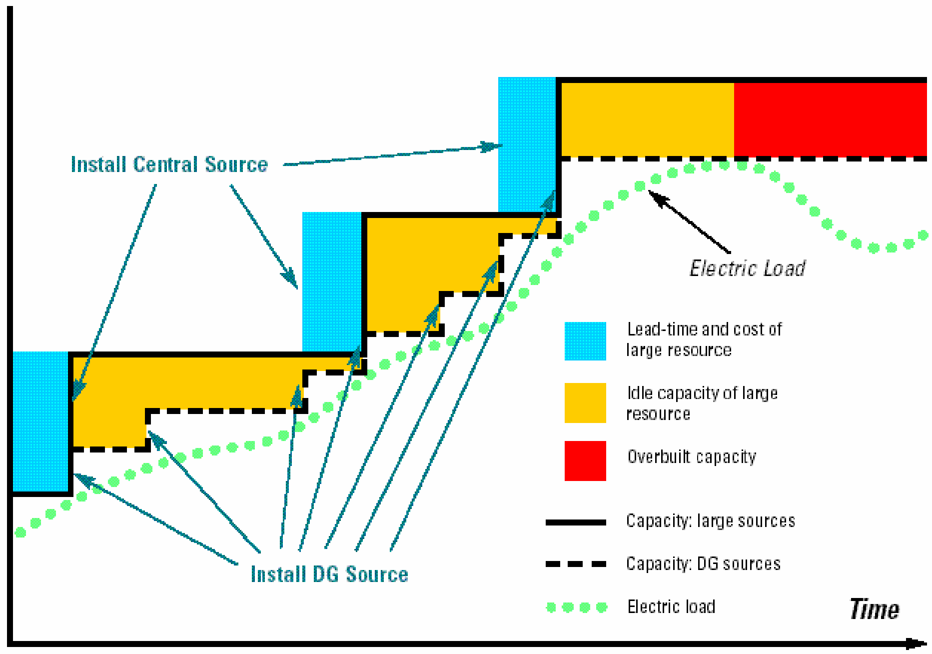

Figure 7-9
Slow, Lumpy Capacity Overshoots Demand[85]

This option value applies even more powerfully to electricity generation. Central generation plants, as well as transmission and distribution capacity, are "lumpy" investments—i.e., they come in large increments. Often, a large unit is built to meet demand that is expected to exceed existing capacity by only a small amount. This leads to excess capacity that remains idle but still incurs costs. Smaller units can reduce the need to overbuild to meet expected but uncertain demand. Traditional utility regulation rewards overbuilding, but the financial discipline of a competitive market will surely penalize producers with idle capacity (see Figure 7-9).

Thus adding smaller modules saves three different kinds of costs: the increased lead time (and possibly increased total cost) of central resources; the cost of idle capacity that exceeds actual load; and overbuilt capacity that remains idle. Both systems maintain sufficient capacity to serve the erratically growing load, but the small-module strategy does so more exactly in both quantity and timing, and hence incurs far fewer costs.

The financial benefits of modular generation also derive from the ability to postpone investment as long as possible. Instead of building a large generation facility and expending capital all at once, modular generation allows a utility to install a small increment of capacity to serve current load growth needs, while postponing investment in additional increments until later.

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[85] Swisher, J. (2002). Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Energy Resources. Rocky Mountain Institute. www.rmi.org/sitepages/pid171.php.

The Value of Short Lead Time

Nearly twenty years ago, M.F. Cantley noted that "the greater time lags required in planning [and building] giant power plants mean that forecasts [of demand for them] have to be made farther ahead, with correspondingly greater uncertainty; therefore the level of spare capacity to be installed to achieve a specified level of security of supply must also increase."[86] Longer lead time actually incurs a double penalty: it increases the uncertainty of demand forecasts by having to look farther ahead, *and* it increases the penalty per unit of uncertainty by making potential forecasting errors larger and more consequential.

The modularity that accompanies small-scale generation can improve the rate of response to demand changes. If new customers suddenly require unexpectedly large amounts of power, then small, modular, DG units can usually enter service faster than large central stations. The short lead-time of smaller units is thus an advantage in responding to increasing demand without building unnecessary idle capacity. Short lead-time also reduces the carrying costs of plants under construction, which can reduce the present-value cost of the plant itself. As in the milk example above, reducing the lead-time also reduces the incentive to overbuild, as it is easier and less expensive to increase capacity in response to demand growth when it occurs.

As an example of the economic benefits of small-scale and short lead-time, consider a perfect distributed generation resource, which can be built in exactly the increments needed to meet annual load growth, with a one-year lead-time. In contrast, a central generation source would have a longer lead-time. Also, because the central source is larger than the annual increments of load growth, some of its capacity remains idle after it is built, until the load growth catches up. The economic costs of this overbuilding are the financial carrying costs of the resource during the period in which it is idle. These can be substantial. For instance, if the central source has a capacity equal to six times the annual load growth, and a four-year lead-time, it carries a 45 percent cost premium compared to a distributed generation source with equal unit cost. Thus, distributed generation could cost 45 percent more per kilowatt and still have the same net present value cost as the central source (see Figure 7-10).

[86] Cantey, M.F. (1979). Questions of Scale. *Options '79 #3*. Laxenburg, Austria: International Institute for Applied Systems Analysis.

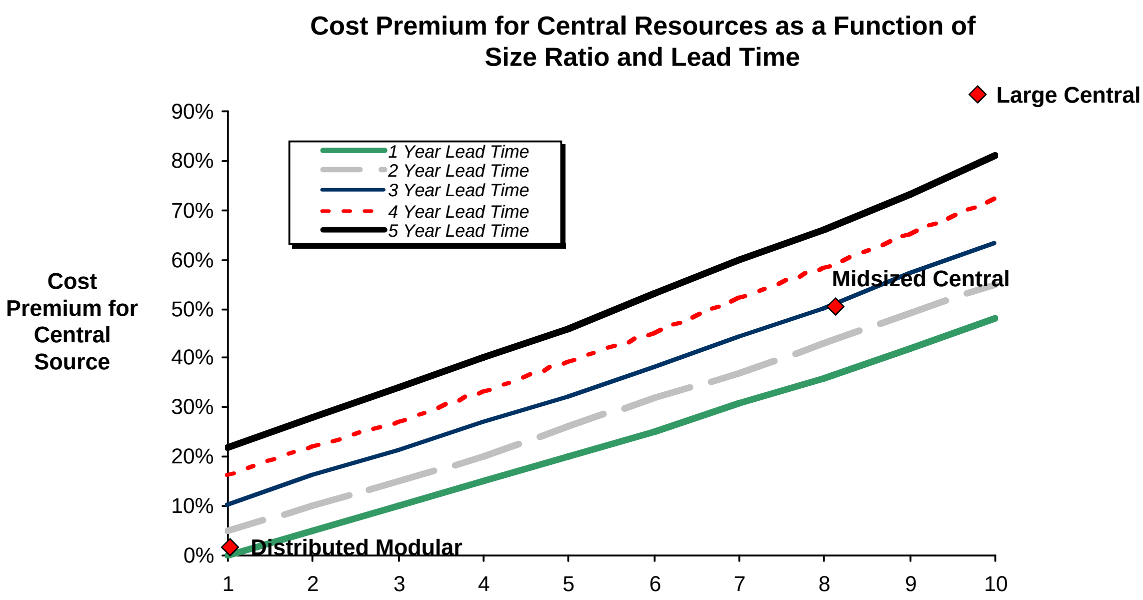

Figure 7-10
Cost Premium for Central Resources as a Function of Size Ratio and Lead Time

The carrying costs shown above do not account for the risk that you did not need the generation facility. This should be analyzed using decision analysis techniques on an expected cost basis.

If you consider the probability of load growth as a binomial probability that load will rise to the level where new generation is needed in time *t*, then the expected costs of generation decrease with decreasing lead time. In essence, you have the luxury of waiting to see whether load does indeed grow as forecast, and if not, the plant is not constructed. If the lead-time = *t*, then you have to build the plant right away. If the lead time is shorter, then the more uncertain you are about the forecast, the less likely you will incur the costs of building unnecessarily, hence the expected cost is lower with lower probability.

When modularity and lead-time benefits are integrated, the financial benefits of distributed resources in managing uncertainty become clear. When modularity is added to the equation (i.e., a large number of smaller plants), there are additional benefits from avoiding unnecessary capacity. The benefits are similar to shortened lead-time: the greater the uncertainty regarding load, the greater the cost savings from modularity.

However, smaller plants cost more due to economies of scale in larger plants. Thus, when the investment cost includes a factor for economies of scale, this will offset the benefit of modularity, and at a scale curve of 80 percent or more, the modularity benefit disappears. Both these equations are provided in spreadsheet format, which allows a relatively easy estimation of the benefits.

Given an illustratively irregular pattern of demand growth characteristic of normal fluctuations in weather and business conditions, excessive reserve margins and electricity prices can be reduced by preferring short-lead-time plants. There are four reasons for this:

- Operating short-lead-time, lower-thermal-efficiency, low-capital-cost stopgap plants (such as combustion turbines fueled with petroleum distillate or natural gas) more than expected, and paying their fuel-cost penalty, is cheaper than paying the carrying charges on giant, high-capital-cost power plants that are standing idle[87];
- Even if this means having to build new short-lead-time power stations such as combustion turbines, their shorter forecasting horizon greatly increases the certainty that they'll actually be needed, reducing the investment's "dry-hole" risk;
- Smaller, faster modules strain a utility's financial capacity far less (for example, adding one more unit to 100 similar small ones, rather than to two similar big ones, causes an incremental capitalization burden of 1 percent, not 33 percent); and
- Short-lead-time plants can be built modularly in smaller blocks, matching need more precisely.

Shorter lead-time and smaller, more modular capacity additions can reduce the builder's financial risk and hence the market cost of capital, but there are even more causes for the same conclusion.[88] Shorter lead-time means:

- Less accumulation of AFUDC, a lower absolute and fractional burden of interest payments during construction[89], higher-quality earnings that reflect more cash and less fictitious "regulatory IOU" book income, and lower cost escalation during the construction interval[90], [91];
- The utility does not have to keep as much capacity under construction, costing money and increasing financial risk, to meet expected load growth in a timely fashion;

[87] Naturally, this sort of conclusion is not immutable, but rather depends on interest rates, fuel costs, and other factors that change over time.
[88] Sutherland, R., Ford, A., Jackson, S., Mangeng, C., Hardie, R., and Malenfant, R. (1985). *The Future Market for Electric Generation Capacity: Technical Documentation.* Los Alamos, NM: Los Alamos National Laboratory (March): 145-146.
[89] Comtois, W. (1977). Economy of Scale in Power Plants. *Power Engineering* (August): 51-53.
[90] Komanoff, C. (1981). Power Plant Cost Escalation: Nuclear and Coal Capital Costs, Regulations and Economics. New York, NY: Komanoff Energy Associates.
[91] Mooz, W. (1978). Cost Analysis of Light Water Reactor Power Plants. R-2304-DOE. Santa Monica: The RAND Corporation.

- Units get into the rate base[92] earlier, or, in the case of a privately owned plant, can start earning revenue earlier—as soon as each module is built rather than waiting for the entire total capacity to be completed;[93]
- Companies receive a longer "breathing spell" after the eventual startup of the large units that are currently under construction (so that they can better recover from the financial strain of those very costly and prolonged projects);
- Decreases the burden on utility cashflow as expressed by such indicators as self-financing ratio, debt/equity ratio, and interest coverage ratios—all used by financial analysts to assess risk for such purposes as bond ratings and equity buy/sell recommendations;[94, 95] and

Less risk of building an asset that is already obsolete—a point important enough to merit extended discussion in the next section.

Technological Obsolescence

As the pace of technological change continues to increase rapidly, technological surprises are increasingly likely. Amid such flux, the more utilities are able to direct their investments to quickly delivered, adaptable units, the less they risk large capital commitments to technologies that are obsolete and uncompetitive even before they're installed. Sinking less capital in costly, slow-to-mature projects, and inflexible infrastructure reduces financial regret, and may also reduce the institutional time constant for getting and acting on new information. Thus, less capital is tied up at any given time in a particular technology at risk of rapid obsolescence; a larger fraction of capacity at any time can use the latest and most competitive designs; and the associated organizations can learn faster.

Regulatory Obsolescence

The cost, siting, and even practical availability of technologies depend on regulatory requirements, tax rules, and other public policies. Continuous conflicts between various groups

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[92] Under traditional U.S. (and most other) rate-of-return regulations, utilities are entitled to charge customers approved tariffs expected to yield "revenue requirements" that consist of two kinds of prudently incurred costs: operating expenses, and a fair and reasonable return on and of capital employed to provide "used and useful" assets. The "rate base" on which the regulated utility has the opportunity to earn that regulated return is thus the sum of those used and useful assets. Therefore, the sooner a power station enters service, the sooner it starts earning returns.

[93] This benefit has been quantified, with an example of a 500-MW plant built in one segment over five years vs. ten 50-MW modules with 6-month lead times. If each asset runs for 20 years, then under either plan, the same capacity operates identically for the middle 15 years—but the modular plant has higher revenue-earning capacity in the first five years, and conversely in the last five years as the modular units retire. But because of discounting, the early operation is worth much more today. Using a 10% per year discount rate and $200/MW-y revenues, the modular solution will have an astonishing 31% higher present-valued revenue. If the modular plant were infinitely divisible and had zero lead time, then regardless of the life of the plant, the ratio of present-valued revenues would be (eLd – 1)/Ld, where L is the number of years it takes to complete the non-modular plant and d is the annual real discount rate.

[94] Kahn, E., and Schutz, S. (1978). *Utility Investment in On-Site Solar: Risk and Return Analysis for Capitalization and Financing.* LBL-7876. Berkeley, CA.

[95] Wiegner, E. (1977). *Tax Incentives and Utility Cash Flow*. Atomic Industrial Forum Conference on Nuclear Financial Considerations. Seattle.

amidst a swirling and ever-changing mass of environmental, social, and economic concerns make the regulatory process often unpredictable in detail (though often rather predictable in a general way), and hence a source of risk just as important as technological obsolescence. Obviously, technologies that can be built quickly before the rules change, are modular so they can "learn faster," and embody continuous improvement are less exposed to regulatory risks.[96]

Project Off-Ramps

Hoff and Herig[97] point out that managers can gain value for a utility not only by deciding when to buy resources but also by deciding when to not buy them: "Modular plants have off-ramps so that stopping the project is not a total loss." Suppose that a series of units is being built, their cost is uncertain, and this uncertainty will be largely resolved when the actual cost of the first unit is known because subsequent units will have similar costs. If the actual cost turns out to be excessive and managers want to cut their losses, then (assuming no salvage value) more value can be recovered if whatever has already been built can operate and yield revenue. Even if investors pull the plug on financing partway through a modular project, they can still get some value from whatever modules were already finished, rather than being stuck with an inoperable piece of an uncompleted large plant.

Portability and Reversibility

Once a power plant is sited and constructed, it's conventionally assumed that it will exist forever, or at least until it's demolished. However, many short-lead-time, small-scale technologies are "sited" only temporarily, because they are inherently portable. That value arises because the resource remains flexible in use throughout its engineered life; it can be physically redeployed to a different site or even a different utility system. Thus if, for example, a photovoltaic array is sited at a particular substation to support expected demand growth that fails to occur, then the array can be disconnected and unbolted (leaving behind only a very small fraction, perhaps nominally around 5 percent, of its value in footers, cables, etc.). It can then be loaded onto a truck and reinstalled at another "hot spot," where its output will be worth more.[98]

A large utility may well wish to maintain a portfolio of flexible, portable resources re-deployable as needed. The concept can be an important risk-reducer for utility planners who want to match temporary or uncertain-duration resources to similar revenue streams, rather than sinking inflexible costs to serve potentially ephemeral loads. Since the dominant benefits are usually to the distribution system, a competitive industry structure in which power is readily "wheelable" should not greatly alter this conclusion. The value of optimal siting of distributed resources

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[96] Komanoff, C. (1981). *Power Plant Cost Escalation: Nuclear and Coal Capital Costs, Regulations and Economics*. New York, NY: Komanoff Energy Associates.
[97] Hoff, T., and Herig, C. (1997). Managing Risk Using Renewable Energy Technologies. *The Virtual Utility: Accounting, Technology and Competitive Aspects of the Emerging Industry.* Edited by S. Awerbuch and A. Preston. Boston: Kluwer Academic. www.clean-power.com/research/riskmanagement/mrur.pdf.
[98] Sometimes this is a deliberate design feature. For example, when Robert Sardinsky was designing a photovoltaic system to power a house being built in a sensitive mountain site, he made the PV system first ground-mounted, to run the construction tools (thus avoiding a smelly and noisy portable generator), then simply installed the PV array on the roof afterwards.

within the network may also be dramatically increased as new software permits nearly instantaneous power-flow optimization calculations on portable computers.[99]

Another aspect of reversibility is that most renewable sources have small and relatively benign impacts on the site where they are installed. In contrast, nuclear units may permanently "sterilize" other resource issues—such as land-use concerns, while most fossil fuel plants entail substantial civil works and some may risk long-term soil and water contamination. These differences affect residual site value and the flexibility of later reuse. Often they give coal plants a small or even negative salvage value.[100]

System Diversity and Resilience

Distributed resources can significantly improve the resilience of electricity supply, thus reducing many kinds of social costs, risks, and anxieties, including military costs and vulnerabilities. A 1982 RMI study, *Brittle Power,*[101] shows that both naturally caused[102] and deliberate disruptions of supply can be made local, brief, and unlikely if electric power and other energy (and non-energy) systems are carefully designed to be more efficient, diverse, dispersed, and renewable. Importantly, too, to the extent that potential disruptions of supply are maliciously caused, resilient design using distributed resources—the strategy of the diverse ecosystem, not the monoculture—will not only blunt those disruptions' effect; it will also thereby reduce the motivation to cause them in the first place, because the difficulty and risk will seem less worthwhile when the effect is so much smaller.

In an age of terrorism, the security benefits of shifting from the central architecture of the power system to a more distributed architecture are not academic. The ability of a small number of insurgents in Iraq to permanently disrupt the central power system should serve as clear evidence of the weakness and vulnerability of central power plants and transmission lines.

In island systems, the problem is magnified since there is no interconnection with other grids to restore power. Further, severe weather events, such as hurricanes and typhoons, can knock out large portions of a central grid. Individual critical facilities, such as hospitals, telecommunications centers, and police stations can maintain power services through distributed generation and switching to distributed resources, allowing an individual facility to isolate itself from the grid and problems within the grid. An even more reliable system would include the creation of microgrids that allow entire groups of buildings to isolate themselves in the event of grid failure.

Distributed systems can be designed to have modular microgrids that can disconnect from the overall power grid during periods of disruption. The more granular the capability to isolate elements of the grid, the greater the resilience to overall disruption (and the easier it is to restore the overall system). Real security benefits require distributed resources and a distribution system designed for these resources.

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[99] This capability is claimed by Optimal Technologies (www.otii.com).
[100] Awerbuch, S., and Preston, A. (1993). *We Do Not Have the Measurement Concepts Necessary to Correctly Implement IRP: A Synthesis and Research Agenda*. Draft Paper. Billerica, MA: Mobil Solar Energy Corporation (August).
[101] Lovins, A., and Lovins, L. (1982). *Brittle Power.* Andover, MA: Brick House. Reposted with related readings at www.rmi.org/sitepages/pid533/php.
[102] For example, major earthquakes or weather events.

8 PRACTICAL METHODOLOGIES FOR DISTRIBUTED POWER RELIABILITY EVALUATION

A system of practical methodologies has been developed to evaluate the potential advantages created by distributed power resources. These methods provide analytic tools that can be used to evaluate the distributed values discussed in the prveious chapter. RMI has developed Microsoft Excel spreadsheet tools for each of the benefits discussed in this chapter. These tools are available upon request at www.rmi.org.

This chapter is organized as a discussion of the mathematical equations required to estimate the distributed resource benefits. In some cases, the appropriate approach is decision analysis, and the tools provide an analytic approximation of the result. For other values, the benefits must be defined by each utility based on its particular distribution grid, and we provide the methodological approach. Finally, in the case of ancillary services, the values are often found in the Independent System Operator (ISO) and Regional Transmission Organization (RTO) markets.

Statistical Evaluation of Availability of Modular Resources

Reliability

As discussed in the previous chapter, the amount of generating capacity necessary to achieve system reliability decreases with relative unit size. In other words, a system composed of a large number of small generating units is more reliable than a system with a small number of large plants. This is true because each individual power plant is treated as an independent random variable, subject to binomial probability.

The National Renewable Energy Laboratory and Dr. Thomas Hoff of Clean Power Research derived an analytic approximation to this effect, which can be used to model the amount of capacity needed to achieve a particular reliability level given an amount of load and equally sized generation units with identical forced-outage rates. This model, a binomial probability distribution analysis, shows that an isolated system seeking 100 kW of firm capacity from dispatchable units with an assumed 5 percent forced-outage rate, to serve a constant load from homogeneous customers, can get that capacity from five 50-kW units, twenty-five 5.26-kW units, or one hundred 1.16-kW units. These three alternative scenarios have total capacities of 250 kW, 131.5 kW, and 116 kW, respectively, so going to the smallest units reduces the required total capacity by 54 percent compared to the larger (50-kW) units.[103]

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[103] Hoff, T., Herig, C., and Shaw, R. (1997). *Distributed Generation and Microgrids*. 18th USAEE IAEE, September. www.clean-power.com/research/microgrids/MicroGrids.pdf.

Of course, the degree to which "a system composed of a large number of small plants is more reliable [than]...a system with a small number of large plants" depends also on how reliable the plants are. The underlying formula is a binomial probability tree that defines the cumulative probability of different levels of reliability based on forced-outage rate. An analytic approximation is:[104]

$$R = \exp\left[A(\ln N)^{B}\right]$$

Where R is the ratio of capacity to load, $A = 1.20 - 0.212\ln(D) + [14.40 - 2.139\ln(D)](FOR)$, $B = -1.159 + 0.1024\ln(D) + [0.1689 - 0.00512\ln(D)]\ln(FOR)$, D is the number of days when demand is expected to exceed capacity in a 10-year period, N is the number of generating units*, and FOR* is the forced-outage rate.

From this formula, families of curves can be plotted showing the capacity savings from smaller units or more reliable units or both. Most utility system simulation models can be used to define the benefit of many smaller distributed plants over a few larger plants, but only if: 1) distributed generators are modeled as individual plants, and 2) optimization uses LOLP criteria, not deterministic criteria.

Binomial Probability Distribution

Binomial probability distribution can be used to describe the decreased uncertainty of output associated with an increased number of generating units. One generating unit has only two possible states of being: "on" or "off." In other words, it is dichotomous. Ultimately, what this analysis is interested in is the probability distribution of x, the number of plants that are "on" at any given time. Therefore, x is a binomial random variable, and the probability distribution of x is:

$$p(x) = \binom{n}{x} p^{x} q^{n-x}$$

where p is the probability that a single generating unit is "on" (*i.e.*, [1-*FOR*]), q is 1-*p (i.e., FOR), n* is the number of generating units, and x is the number of generating units that are "on" out of n possible units.

$$\binom{n}{x} = \frac{n!}{x!(n-x)!}$$

Therefore, *p(x)* is the probability that x generating units out of a possible n are "on." To convert from number of generating units "on" to power output, simply multiply by generating unit size, L/n, where L is the combined rated power output of generating units.

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[104] *Id.*

The mean, μ, and standard deviation, σ, of the power output probability distribution can be calculated as:

$$\mu = Lp$$

$$\sigma = \frac{L}{n}\sqrt{npq}$$

The user inputs the values for *p* (availability of generating units, *i.e.*, [1-*FOR*]), *n* (number of generating units), and *L* (combined rated power output of generating units).

Ability of Distributed Resources to Meet Ancillary Services Definitions

"Ancillary services" refers to the ability of the power system to *deliver* energy in a usable form after it has been produced by power generators. Ancillary services were previously bundled in the energy and capacity prices, but are now, in some locations, separately purchased by the ISO in order to meet the reliability needs of the bulk energy system. Certain distributed resources can provide particular ancillary services.[105]

Market Valuation of Ancillary Services

Most ancillary services are priced by the ISO- and RTO-managed power markets. This is true for spinning reserves, non-spinning reserves, and regulation energy. The definitions of these ancillary services, the ability of distributed resources to enter into these markets, and the current valuation of these services can all be found on the power market web sites of Pennsylvania-New Jersey-Maryland Interconnection (PJM), NEPOOL, California ISO (CAISO), ERCOT, Mid-Continent Area Power Pool (MAPP), etc. Therefore, we will not elaborate on them here.

We note that while distributed generation units are universally recognized as being able to provide these ancillary services, not all power markets recognize the value of demand-side resources. We anticipate that market rules will be adjusted as time goes on.

Regulated Valuation of Ancillary Services

For regulated utilities that cannot directly purchase ancillary services from a wholesale power market, the question arises as to how to value these services. The answer is that we should value these services based on the avoided cost of providing them using conventional generation.

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[105] Weston's "Model Regulations for the Output of Specified Air Emissions From Smaller-Scale Electrical Generation Resources," notes that distributed resources are generally well suited for Network Stability and Contingency Reserves when connected to the grid, and providing they are dispatchable by the ISO. The characteristics of the distributed resources, in particular its response time, response duration, and ability to be dispatched, will determine its suitability in helping to maintain or restore the real-time balance between generators and loads (e.g., Regulation, Load Following, Frequency Responsive Spinning Reserves, Supplemental Reserve, and Backup Supply).

Thus, for spinning reserves, it is the cost of the generating unit, and the fuel necessary to keep it in synchronous rotation with the grid. For non-spinning reserves, it is the carrying costs for the generation unit (annualized capital cost plus fixed operations and maintenance). For regulation energy, it is the annualized cost of the generation unit, plus the fuel cost of maintaining that unit at below optimal output, plus the marginal fuel costs of providing the regulation energy, plus any control technologies. The same equation would hold for generation units that provide frequency control.

Methodologies for Calculating Marginal Distribution Capacity Cost (MDCC)

Deferral of System Upgrades

An almost universal benefit of distributed resources is the ability to defer or avoid adding grid capacity. Depending on where the resource is installed, distributed resources may displace grid capacity at all levels from the local tap or feeder all the way upstream to the power-plant switchgear and step-up transformer. The further downstream the distributed resource is sited, the greater are the avoided compounding grid losses and hence the more capacity that is displaced. Obviously, a distributed resource displaces the capacity it sends out (or saves, if it is a demand-side resource). However, a distributed resource also displaces the capacity it frees up by reducing line losses.

Most utility planners prefer to evaluate displaced grid capacity as a deferral rather than an outright avoidance, since they are used to dealing with steady load growth that sooner or later outruns the previous “lump” of installed grid capacity. The deferral value is then the difference in present value between the normal installation schedule and the deferred one. (If the analysis uses a fixed time horizon, then the extra value of buying the capacity later, and hence possibly having it last beyond that horizon, must be taken into account).

For example,[106] if

- a new distributed resource were located in the right place and at the right time on a radial distribution system where a 10.5-MVA distribution transformer is approaching its maximum capacity,
- the preferred alternative were an upgrade to a 16-MVA transformer with an installed cost of ~$1.15 million (1992 $),
- the old transformer had negligible salvage value because it was fairly old, and
- a 0.5-MW PV resource contributed power on the transformer’s low-voltage side, highly available at peak loads, then

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[106] Shugar, D., Orans, R., Jones, A., El-Gassier, M. and Suchard, A. (1992). *Benefits of Distributed Generation in PG&E’s Transmission and Distribution System: A Case Study of Photovoltaics Serving Kerman Substation*. PG&E.

- that modest resource might enable the transformer to operate "within its load limit throughout the year, deferring the need for a larger transformer. Given load growth forecasts and the amount of distributed generation available, one can estimate the number of years for which the installation of the larger [...] transformer can be deferred."[107]

Hence one can estimate the economic value of that deferral—in this case, $115 per kW-year for a five-year deferral.[108] Reconductoring distribution lines through the same PV resource's ~25-A onpeak reduction in an aboveground, non-urban standard 12-kV line would save on the order of $27,000–$46,000 per kilometer (1992 $), depending on whether an old line was reconductored or a new line constructed.[109] Transmission capacity directly deferred by the distributed resource's modest output would be relatively less important because a half-MVA is such a small part of a typical transmission line's capacity, but more "significant for the transmission system are loss savings and the transmission system capacity value associated with reduced load, which apply regardless of the reduction's magnitude."[110]

That is,[111] "in addition to providing power loss savings, the reduction of current on transmission and distribution lines attributable to loss savings frees transmission capacity for service to other customers." The loss savings can be determined from loadflow simulations and the system average marginal transmission capacity cost ($282/kW in PG&E's 1990 General Rate Case filing), unless, preferably, a more site-specific and time-specific cost is known.

This "decongestant" property is, of course, most valuable at the times and places where the grid is most congested, and should attract compensation based on the "congestion rent" that a market-priced common-carrier grid does or should charge.[112] Naturally, evaluating the value of transmission capacity is very complex, depending not only on marginal cost of new capacity but also on the time- and space-varying capacity/demand balance, projected power-wheeling economics, and supply-side options and locations. However, this task is rapidly shifting from theoretical analysts to market actors whose real-time behavior will offer an increasingly available and convenient guide to economic value and who are motivated by profit to seek out the most lucrative hot-spots in the system.

Calculation of MDCC

A utility's traditional method for determining costs is limited to include the average system marginal capacity costs (MCC) and the marginal energy costs (MEC) only. However, in order to account for the benefits of distributed generation, a utility's cost methodology should include the area- and time-specific marginal costs (ATSMC), which enables utility planners to target areas where the marginal benefits of employing distributed resources are at a premium. This is especially important where substantial capital is needed for distribution system upgrades that could be partially avoided or deferred by the systematic use of area- and time-specific costs.

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[107] *Id.*
[108] *Id.*
[109] *Id.*
[110] *Id.*
[111] *Id.*
[112] Lovins, A. (1995). Comments on FERC's Mega-NOPR. RMI Pub. U95-36 (July).

Rather than focusing on generation and bulk transmission costs, as is the case with traditional utility costing methods, ATSMC is predicated on the transmission and distribution costs. Thus, ATSMC serves as an indicator of a utility's marginal costs and measures the avoided costs incurred from distributed resources. The equation for ASTMC is:

$$ATSMC = MEC * \delta kWh / crf + MCC * \delta kW_{sys} + MDCC * \delta kW_{area}$$

Where MEC is the marginal energy cost (depends on amount of system-wide energy reduction), MCC is the marginal system-level capacity cost (depends on system expansion plan), MDCC is the marginal distribution capacity cost (depends on local area expansion plan), kWarea is the savings in distribution capacity (depends on time of area peak demand), kWsys is the savings in system-level capacity (depends on time of system peak demand), kWh is the savings in annual energy use (depends on load-factor of affected end-use), and crf is the capital recovery factor (depends on discount rate and amortization time).

As Joel Swisher and Ren Orans point out in their paper, *The Use of Area-Specific Utility Costs to Target Intensive DMS Campaigns*, "In practice, each of the terms in the equation above is evaluated for each hour of the year, and the results are added to estimate the full marginal costs.

An important component of ATSMC is the area- and time-specific value of the marginal costs of distribution and local transmission capacity (MDCC). Assessing MDCC requires a local distribution supply and expansion plan that includes each area's future load growth and related investments in capacity expansion."[113]

To develop an area-specific distribution supply plan, a utility planner should estimate excess capacity by subtracting the area's current load from capacity, divide excess capacity by the respective forecasted annual load growth, and prepare an expansion plan, which includes a time schedule for necessary investments. An investment time schedule provides the cost data from which the MDCC can be estimated.

To accurately incorporate the time and area value of distributed resources, the MDCC equation employs a present-value approach to assess the value of expanding now versus deferring the expasion later in time.[114] According to Swisher and Orans, "To achieve any deferral value, it is necessary to displace the area load growth for at least one year. The minimum DR program size is therefore in the range 500–2500 kW for most residential areas. Minimum penetrations of 300 to 1600 1.5-2 kW units within an area are required to capture deferral value in most high-cost areas."[115]

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[113] Swisher, J. and Orans, R. (1996). The Use of Area-Specific Utility Costs to Target Intensive DSM Campaigns*. Energy and Environmental Economics.*
[114] Orans, R., Woo, C., Swisher, J. (1992). *Targeting DSM for Transmission and Distribution Benefits.* Electric Power Research Institute, EPRI TR-100487.
[115] Swisher, J. and Orans, R. (1996). The Use of Area-Specific Utility Costs to Target Intensive DSM Campaigns*. Energy and Environmental Economics.*

$$MDCC = \left\{ \sum_t \left[K_t \big/ (1+r)^t \right] - \sum_t \left[K_t * (1+i)^s \big/ (1+r)^{t+s} \right] \right\} \Big/ (s \delta kW_{area})$$

where K_t is the investment in year t, i is the inflation rate net of technological progress, r is the utility's weighted-average cost of capital, and s is the (peak load reduction) / (annual load growth).[116]

The MDCC is generally applied to the hours that affect distribution capacity, or 60–100 hours per year of maximum area-specific demand.[117] Feeder asset utilization is poor in many utilities, and so understanding the expected asset utilization is important to designing DSM programs to defer or avoid new capacity.

MDCC can expose opportunities for applying targeted DSM more effectively than would be called for under traditional utitlity costing methodologies. For example, since MDCC will be driven by the area's demand peak as opposed to the system peak, the measure may expose times when the two peaks diverge. In this case, MDCC could reveal an opportunity where a DSM program would have an effective impact to reduce an area-specific load, which would otherwise be missed. In another example, in a utility with slow system load growth, the transmission and distribution needs could represent a large proporition of the near term required investments. In this case, MDCC will reveal the high value of appropriately applied DSM programs, which would defer "lumpy" distribution capacity investments and provide greater flexibility for the utility.

Screening Methodologies for Distributed vs. Central Resources

This analysis addresses the economic benefits of modularity and short lead times. Forecast load uncertainty is not taken into consideration in this section, but it is in subsequent sections. Lead time refers simply to the amount of time necessary for construction, while modularity refers to the ability to build smaller modules of generating capacity as needed rather than building a single large generation facility up-front.

At a screening level, the financial benefits of distributed generation versus those of centralized resources depend on the lead-time and the size-to-load ratio. In essence, the larger the size of the resources relative to load growth, and the longer the lead time required to build it, the higher the cost of building the resource and owning the excess capacity compared to building a perfectly-sized resource, with a 1-year lead time. In the case of relatively small systems, the premium can be well above 50 percent, just from the direct financial holding costs. Many current planning models should reflect these values as long as the financial costs of building capacity and of owning excess capacity are incorporated.

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[116] *Id.*
[117] *Id.*

Net Present Value

Consider a perfect distributed generation resource, which can be built in the exact increments needed to meet annual load growth, with a 1-year lead-time. In contrast, a central generation source would require a longer lead-time. Also, because the central source is larger than the annual increments of load growth, some of its capacity remains idle after it is built, until the load growth catches up. To value these lead-time and modularity benefits, the model calculates the increase in the net present value (NPV) cost of the central generation source compared to the DG source with the *same unit ($/kW)* cost. This NPV increase is calculated as:

$$\Delta NPV = (1+d)^{R} \cdot (1+d)^{L-1} \cdot \frac{R}{L} \cdot \frac{(1+d)}{(1+d)^{R-1}}$$

where d is the real discount rate, R is the size ratio, which is incremental capacity of a central resource divided by the incremental load growth, and L is lead time which is equal to the central resource lead time (in years).

However, this neglects the risk of overshooting demand. Although we can forecast demand, actual demand is uncertain. The analytic question is which method should be used to determine the value of mitigating the uncertainty in load. Discounted cashflow is widely used today, but it does not incorporate flexibility. Option valuation is a financial technique, but requires market-traded assets with identical risk and cash flow characteristics. The real option method avoids some of this problem. The decision analysis approach is well-suited for the task, but you need to know the probabilities and outcomes.

Load Uncertainty

When new generation must be constructed in response to demand growth, but the timing of demand growth is uncertain, Hoff attributes financial benefits to generating capacity with short construction lead times and modular installation. To examine these benefits, Hoff considers a model in which the uncertain load growth is considered probabilistically, and generation construction costs are calculated as *expected values*. The financial benefits of short lead times and modular expansion both derive from the fact that future dollars are discounted to be worth less than present dollars, and that these two characteristics of capacity expansion allow investments to be postponed as long as possible.

In general, these short lead times and modularity are most valuable when demand growth is very uncertain. In these cases, the benefits of modularity more than offset possible increased per-kilowatt costs of smaller generation units.

Incorporating Load Uncertainty and Lead Time

Thomas E. Hoff has analyzed the impacts of modularity, lead-time, and load uncertainty on the value of distributed generation.[118] Based on this work, this discussion denotes T as the number of years of load growth necessary to consume existing excess generating capacity—i.e., new

[118] Hoff, T. (1997). *Integrating Renewable Energy Technologies in the Electric Supply Industry: A Risk Management Approach*. NREL/SR-520-23089. Golden, CO.

generation may be needed as soon as *T* years in the future. However, since load growth each year is uncertain, the new generating capacity may not *actually* be needed until significantly later. For instance, there may happen to be *k* years of zero or negligible load growth, where *k* can range from zero years to (theoretically) infinite time. New generation would not actually be required until *T+k* years from the present.

Now, if *L* is the lead time for construction of new generation, capital *must* be expended on a new plant *T-L* years from the present, in order to guarantee that construction of the necessary new plant will be completed "in time," even in the worst case scenario in which $k = 0$ and load actually does grow for each of the next *T* years. Thus we begin to see the benefit of shorter lead times: the ability to "wait and see" whether load will grow for as long as possible before hitting the "trigger point" at which new construction *must* begin.

If load will grow in a single year with probability *p* (and not grow with probability *1-p*), then the probability of having *k* years of load stagnation intermixed with *T-L* years of load growth is:[119]

$$\binom{k+T-L-1}{T-L-1}(p)^{(T-L)}(1-p)^{k}$$

For each given *k,* the cost of constructing a new increment of generation is given by:[120]

$$\frac{I}{(1+r)^{(k+T-L)}}$$

where *I* is the cost of the generation investment, *r* is the discount rate, and the investment is discounted *k+t-L* years into the future.

The expected value of the cost to add new generation, then, is simply the cost for each given *k* multiplied by the probability of that *k*, with this product summed over all possible values of *k*.[121]

$$E[\cos t] = \sum_{k=0}^{\infty}\binom{k+t-L-1}{T-L-1}(p)^{(T-L)}(1-p)^{k}\frac{I}{(1+r)^{(k+T-L)}}$$

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[119] *Id.*
[120] *Id.*
[121] *Id.*

The equation above simplifies to:[122]

$$E[\cos t] = I\left(\frac{1}{1 + r/p}\right)^{(T-L)}$$

Using the formula above, we can demonstrate the expected cost of installing new generation for several different values of *p* (the probability that load will grow) and *L* (the lead time for new construction). Two things can easily be seen:

- If $T=L$ then the value of the generation investment cannot be discounted into the future—construction must begin immediately; and
- As *p* gets lower and lower, the benefits of short lead times become more pronounced, since there is a very good chance that load will *not* grow in any given year, and a short lead time may allow a utility to postpone investment in new generation for a very long time.

Integration of Modularity and Lead Time Benefits for Total System Value

When modularity and lead-time benefits are integrated, the financial benefits of distributed resources in managing uncertainty become clear. When modularity is added to the equation (i.e. a large number of small plants), there are additional benefits from avoiding unnecessary capacity. The properties are similar to lead-time-related benefits—the greater the uncertainty regarding load, the greater the cost savings from modularity.

However, smaller plants cost more due to economies of scale in larger plants. Thus, when the investment cost includes a factor for economies of scale, this will offset the benefit of modularity, and at a scale curve of 80 percent or more, the modularity benefit disappears.

The financial benefits of modular generation also derive from the ability to postpone investment as long as possible. Instead of building a large generation facility and expending capital all at once, modular generation allows a utility to install a small increment of capacity to serve current load growth needs while postponing investment in additional increments until later.

Hoff developed a stylized model (in which all units are of equal size) that helps test the benefit of modularity. The model divides the total generation capacity to be added into *N* increments, each to be installed *t* years after the initial "investment trigger." Using the formula derived above, the expected value of the cost of installing one of these increments is:[123]

$$E[\cos t] = I'\left(\frac{1}{1 + r/p}\right)^{(T+t)-L}$$

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[122] *Id.*
[123] *Id.*

where *I prime (I')* is the cost of a single increment. Thus, the total expected cost of the entire capacity addition is the sum of all *N* increments.[124]

$$E[\cos t] = \sum_{t=0}^{N-1} I' \left(\frac{1}{1 + r/p} \right)^{(T+t)-L}$$

The formula above then simplifies to:[125]

$$E[\cos t] = I' \left\{ 1 + \left(\frac{p}{r} \right) \left[1 - \left(\frac{1}{1 + r/p} \right)^{N-1} \right] \right\} \left(\frac{1}{1 + r/p} \right)^{(T-L)}$$

Now, consider the cost (*I'*) of a single increment. This cost should be related to the total cost of the entire generation addition *I*. However, the cost is likely to be more than simply *I/N*, since economies of scale dictate that larger generation units will have lower per-kW costs than smaller ones. In this case, some correction should be applied to this *I/N* estimate to reflect the increased per kW-costs of a smaller unit.

For this model, we assume an economy of scale rule that if the size of a generation unit doubles, then the per-kW cost drops to a factor *s* of the previous value, where *s* is a number such as 80 percent. Constructing an inverse to this rule, which describes the increased costs of smaller units, we derive the following correction formula:

$$I' = corrected[I/N] = (I/N)(s)^{\frac{\ln(1/N)}{\ln(2)}}$$

Thus, the final formula for the expected total cost of adding additional capacity in small increments is:

$$E[\cos t] = \left(corrected\left[I/N \right] \right) \left\{ 1 + \left(\frac{p}{r} \right) \left[1 - \left(\frac{1}{1 + r/p} \right)^{N-1} \right] \right\} \left(\frac{1}{1 + r/p} \right)^{(T-L)}$$

Using the formula above, we can demonstrate results across a variety of different values for *p* (the probability that load will grow in a given year) and *N* (the number of increments into which the total capacity addition will be divided).

- If *N=1*, then all additional capacity is added at once, yielding results identical to the previous section in which modularity is not considered.

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124 *Id.*
125 *Id.*

- Modularity is of greatest benefit when the probability of load growth is very low, and/or the additional per-kW cost of smaller units vs. larger ones is very low.

9
CONCLUSION

While Integrated Resource Planning (IRP) has proven to be a valuable tool for evaluating the tradeoffs between supply and demand-side, traditional IRP is generation-centric and typically fails to take into account the costs and benefits of the transmission and distribution system and potential benefits of distributed resources. In our experience, utility planning tools such as PROMOD or UPLAN do not adequately evaluate the portfolio benefits of demand-side, and distributed and renewable resources. For example, renewable resources are often treated as entirely intermittent or as-available, and given no capacity credit in such models. We believe that the proper approach to society's stated goal of emphasizing renewable sources, efficiency, and distributed resources should not be to artificially favor these resources through fake quotas; rather, their unique costs and benefits should be properly valued, and implementation programs to capture such benefits should be designed.

Rocky Mountain Institute's approach to IRP is based on Dr. Joel Swisher's 1997 textbook on IRP methods[126] and on RMI's recent ground-breaking treatise on distributed power, *Small is Profitable: the Hidden Economic Benefits of Making Electrical Resources the Right Size.*[127] RMI found that distributed resources can provide significantly higher economic benefits than typical utility planning tools recognize. Those benefits include financial risk management, electrical grid impacts, power quality and reliability, and reduced environmental impacts. RMI has codified its insights on how to incorporate renewable, distributed, and demand-side resources into the planning process with its Energy Resource Investment Strategy (ERIS) methodology, which is being applied by the cities of Palo Alto and San Francisco.

Generically, ten fundamental tasks must be accomplished during IRP as shown in Figure 9-1. We will focus on the areas that need to be augmented to incorporate renewable and distributed resources.

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[126] Based on the analysis methods presented in: Swisher, J., Jannuzzi, G., and Redlinger, R. (1998). *Tools and Methods for Integrated Resource Planning: Improving Energy Efficiency and Protecting the Environment*, UNEP Collaborating Centre on Energy and Environment, Denmark. http://uneprisoe.org/highlights.htm#irp.
[127] See www.rmi.org or www.smallisprofitable.org.

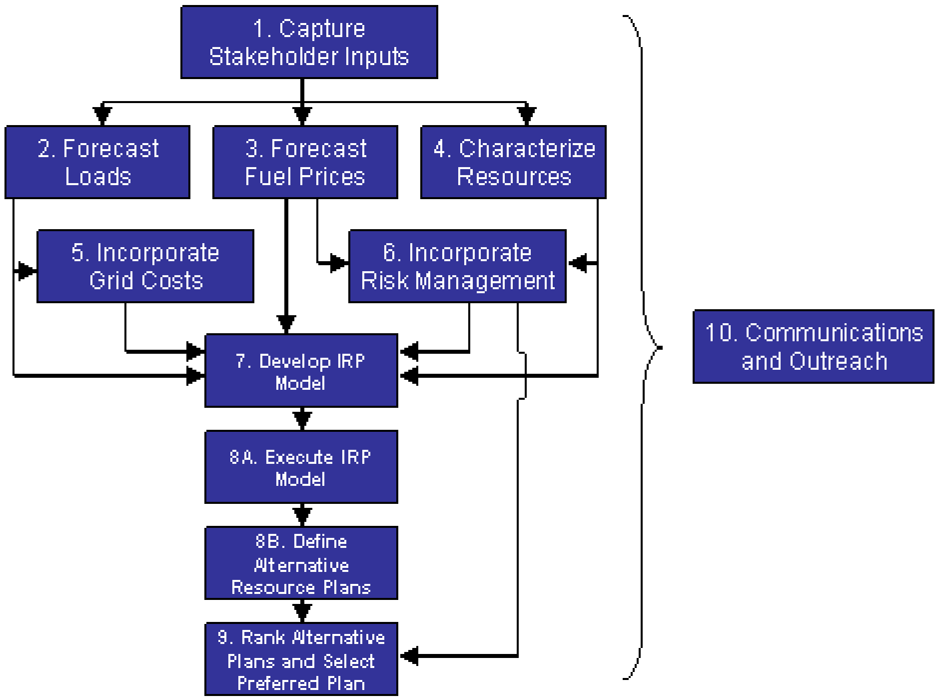

Figure 9-1
Approach to Integrated Resource Planning

Load Forecasts

The most important aspect of load forecasting under the ERIS approach is that the resulting forecast is a probabilistic representation of expected load growth. The ability to define the future load as a probability statement, "a 90 percent chance that load will grow by at least 100 MW within 5 years," for example, is critically important to evaluating the risk mitigating benefits of shorter lead times. This is contrasted with the traditional methodology of using equally likely scenarios for load growth.

In defining the probabilistic forecast, we believe that utilities will be well served by developing the end-use forecasting model as primarily a "bottom-up" approach, which is then adjusted based on observed and forecasted utility loads (i.e., a "top-down" forecast).

There are two main approaches to forecast a utility's electricity sales and peak demand. The bottom-up approach we propose is built on the following accounting identity: the total monthly megawatt-hours by end-use and customer class is the multiplicative product of: (a) number of customers in the class, (b) class-specific end-use saturation rate, and (c) class-specific monthly end-use average kilowatt-hours. One can forecast (a) number of customers using standard statistical techniques (e.g., time series). Forecasting (b) class-specific end-use requires an end-use saturation rate model (e.g., a logit equation), which relates end-use ownership to customer characteristics. This model can be estimated using data from saturation survey and customer billing information. Forecasting (c) class-specific monthly end-use average kilowatt-hours, requires an estimate of end-use average kilowatt-hours, which can come from either end-use metering that directly provides the estimate; or via conditional demand analysis that decomposes a customer's total consumption into end-use specific estimates.

Commonly known as the top-down approach, the second method uses utility-level data (e.g., monthly sales [MWh] and demand [MW]) to build a model that relates sales and demand to their key drivers (e.g., seasonality, weather, income, population, employment, price, and other factors). While providing an aggregate forecast, it offers limited insights for energy efficiency planning alone since changes in the portfolio of end-uses may affect the utility's future sales and demand. A telling example is the replacement induced by a rebate program, in which old refrigerators are replaced with new energy-efficient units. Hence, it is often used in connection with a bottom-up forecast for portfolio planning and integrated resource planning.

Aggregation links the end-use and top-down approaches. The sum of a class's total monthly end-use specific energy (MWh) forecasts is the class-specific energy (MWh) forecast. The sum of class-specific forecasts is the utility-level forecast. However, the utility-level forecast based on the end-use approach may differ from the one based on the top-down approach. If desired, reconciliation between the two forecasts can be done by calibrating the backcasts produced by the two approaches with historic aggregate data. This is the approach that been historically used by the California Energy Commission.

Fuel Price Forecasts

The critical distinction in the fuel forecasting approach is quantitatively defining the volatility of fossil fuels and the covariance among fuels. Most commodity prices, including those of fossil fuels like oil, gas, and coal are influenced by three factors: 1) supply and demand fundamentals, 2) perceived market risk, and 3) technical trading. Since forecasting the absolute price of a commodity is difficult to do in the long run, most utilities use scenarios. However, this approach is deterministic—it assumes we are in a particular scenario. We believe a better approach is to use market data to understand the near-term fuel forecast and associated volatility, since most IRP decisions are made within the first five years, and the plans are typically updated on five-year cycles. While longer-term prices may still use a scenario method, each scenario should include an associated volatility of prices.

Utilities can analyze financial market data to define the near-term fuel forecast and the associated expected volatility—for example, the New York Mercantile Exchange (NYMEX) futures market can be used to examine the five-year forecast for market expectations of future prices. Analysis of the futures market will estimate the underlying volatility that is embedded in futures and options prices.

As discussed in RMI's recent book, *Winning the Oil End Game*,[128] oil is a highly volatile commodity. In conjunction with the Chicago Climate Exchange, we determined that in March 2004, over a five-year time horizon, the market valued oil-price volatility was ~$3.8 per barrel, a ~10 percent premium over the prevailing market price. This analysis was based on the forward costs of Asian options, which entitle the holder to buy oil for cash five years hence, at the average price during the five-year period. Both the price and volatility in oil markets have increased since then.

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[128] Available for download at www.oilendgame.org.

In present-value terms, the majority of the important decisions and costs associated with the IRP will be those that occur within the first 10 years, because the IRP itself will be updated by the end of that time. Nonetheless utilities should extend the duration of the option period to define the value of avoided volatility for 10-, 15-, and 20-year periods. This is important because renewable and efficiency resources provide a hedge against this volatility. Financial economics requires that any risk premium on oil price be included for a properly risk-adjusted comparison of oil with such alternatives.

Fuel costs should also include an estimate of future carbon dioxide management costs that can be used to estimate the full future value of different fossil fuels and biofuels. RMI and Energy and Environmental Economics (E3) developed an approach for defining the future value of offsetting greenhouse gas emissions for the California Public Utilities Commission's (CPUC) avoided cost methodology for DSM programs, which was adopted in December 2004 for purposes of long-term resource planning and procurement decisions. This valuation was for purposes of defining future (albeit uncertain) costs, rather than externalities. In a 7 April 2005 decision, the CPUC adopted a 2004 annual levelized value of $8 per ton of carbon dioxide escalating at 5 percent per year.

Avoided Transmission and Distribution Cost Analysis

The most challenging aspect for estimating marginal transmission and distribution avoided costs is compiling the necessary data, which can include the capital budget plan and load-growth estimates. To calculate avoided costs we need the costs and timing of planned capacity expansions of the distribution system. Only those investments that are driven by growth in the area and could potentially be deferred would be relevant to this analysis. Typically these are on a shorter time frame than IRPs, often only 3 to 5 years in the future. Beyond this time horizon, the average ability for distributed resources to defer distribution investment must be used.

Revenue requirement scalars are used to adjust direct capital costs to fully loaded costs. The full loading scalars are used to convert direct investment costs to fully-loaded revenue requirement levels. The loading accounts for tax effects, return on investment, operations and maintenance, and other items not explicitly included in budgetary estimates.

The proposed distributed resources defined in resource characterization must then be screened to determine whether they could be deployed with enough concentration to defer distribution capacity resources. In practice, this is an issue of the penetration rates of customers required against a particular circuit or set of circuits in order to defer an upgrade.

Approach to Risk Management

As discussed in the beginning of this report, RMI supports a quantitative approach to risk management in the IRP process. The Institute's approach to this complex challenge is simple and direct. Since the load forecast and fuel forecast incorporate the underlying demand uncertainty, fuel price volatility, and future greenhouse gas management costs, we can quantitatively define the ability of different resource mixes to manage these risks. This will allow utility management to make an informed tradeoff between resource portfolios that have different expected costs and probability distributions. For example, a resource mix with a larger degree of renewable power may have a larger expected cost, but a narrower range of uncertainty compared with a more conventional generation portfolio (Figure 9-2).

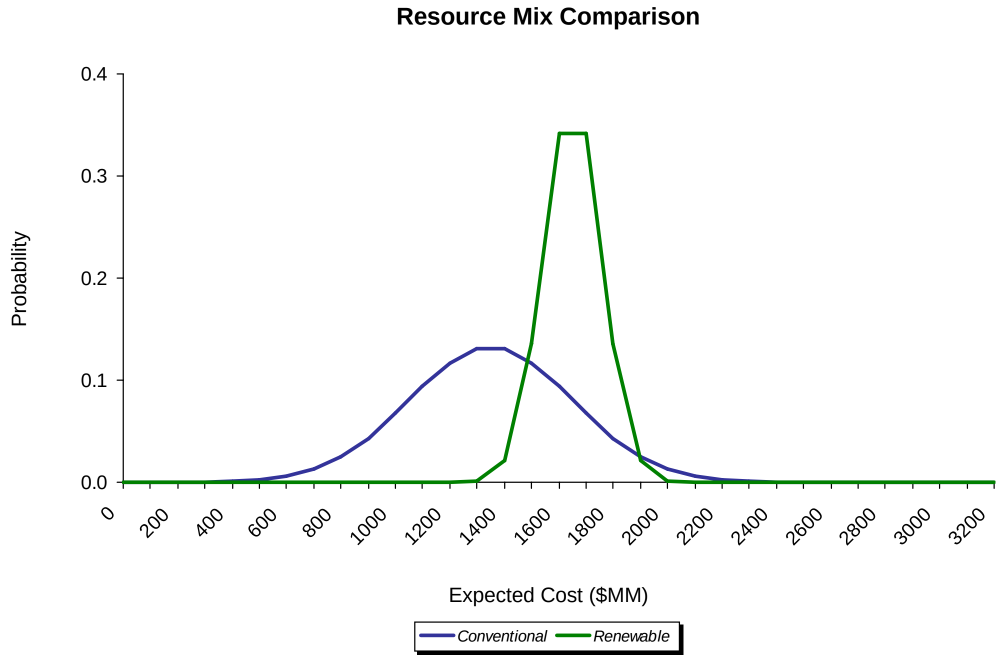

Figure 9-2
Expected Cost Probability for Portfolios with Different Resource Mixes

We believe this approach is superior to adding a standard dollar per megawatt-hour premium to reduce the cost of preferred resources, such as renewables. The adder approach was used when the IRP process was first developed in the 1980s, and our understanding of risk management has progressed significantly since then. A more probabilistic approach based on decision analysis provides more understanding of the relative risk-reward of each resource mix.

The Energy Resource Investment Strategy method applies portfolio theory to combine different mixes of resources along an efficient frontier with respect to fuel price risk. In essence, renewable resources and energy efficiency act as a hedge against fossil fuel resources in the same way that treasury bonds reduce risk in a financial portfolio.[129] As in financial theory, combining low-risk assets with high-risk assets improves portfolio performance by raising expected returns without increasing overall risk. By combining different mixes of renewable resources with fossil-fuel resources, we can create an efficient frontier, defined as the mix of resources that provide the minimum expected cost for the desired risk level. Portfolio combinations that do not lie along the efficient frontier can be eliminated. Utility management can then define its preferred risk tolerance along this efficient frontier, and decide what degree of price volatility it is willing to accept against its risk-aversion criteria.

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[129] Awerbuch, S. and Berger, M. (2003). *Applying Portfolio Theory to Electricity Planning and Policy-Making*. IEA/EET Working Paper.

RMI’s approach provides utility management with the ability to express its risk-aversion levels to higher costs for their ratepayers by specifying the percentile of the probability distribution to be protected against, as recommended in the scoping document, *and* to specify which set of resources along the efficient frontier represent the best tradeoff between lower expected cost and lower underlying uncertainty.

Our approach is shown in Figure 9-3:

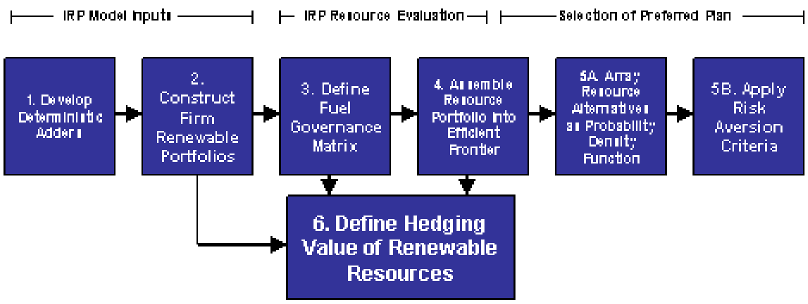

Figure 9-3
Approach to Risk Management

The following paragraphs provide more detail regarding RMI’s risk-management methodology.

Step 1 consists of constructing firmed renewable portfolios. Renewable and distributed resources will be bundled together into portfolios that provide the same equivalent firm capacity as conventional resources (e.g., identical effective load-carrying capacity or ELCC). In our experience, resource diversity and geographic dispersion of renewable resources can reduce the variance of a portfolio of renewable resources due to negative covariance between the individual resources. We will select a mix of renewable sources in the portfolio to minimize their output variability at a given level of output. These renewable portfolios can then be combined with energy efficiency and distributed resources (including storage) to create the same firm equivalent of conventional resources (e.g., same ELCC). The output of this step will be used on inputs into the IRP model.

Step 2 consists of defining the resource covariance matrix for fuels. Renewables and efficiency have no fuel price risk associated with them, so they are risk-free resources with respect to fuel. A covariance matrix does need to be constructed for other fossil fuels in order to define their correlation coefficients. Studies by Awerbuch have found that significant positive correlation exists between gas, oil, and coal. More recent analyses of the run-up in energy commodity prices reinforce this conclusion.

Step 3 involves combining resource portfolio options into an efficient frontier. We will again use the concept of the efficient frontier to assemble sets of resource options with the best possible combination of cost and fuel price risk. The generation efficient frontier will be built based on the principles of financial portfolio theory, so that the resulting charts can be interpreted in much the same way as traditional financial portfolio analysis. This will be used as part of the process for evaluating resource options.

Step 4 requires arraying alternative portfolio options as probability-density functions. To help utility management understand the choices along the efficient frontier, we will array the portfolio options as probability-density functions, with an expected value and standard deviation. For each portfolio, a range of risk-aversion levels, from 5 to 50 percent, can be applied. This will enable a utility to define its options for risk aversion within and between each resource portfolio as part of selecting the preferred option.

Step 5 defines a hedging value of firmed renewable sources. For the firmed renewable portfolios constructed in Step 1, the analyst determines the avoided fuel value, or hedge that the renewable portfolio provides, as discussed in the previous chapter. To recap, this involves aggregating the annualized costs of the renewable and distributed assets and subtracting the annualized capital and fixed operating and maintenance costs of the conventional resources they displace. The remainder is the annual variable cost of fuel and variable operating and maintence costs. These are converted into equivalent fuel prices based on the appropriate heat rates for the displaced energy.

In addition to benefits of renewables in mitigating fuel price risk, distributed resources help mitigate the risk of overshooting or undershooting the load forecast. Smaller, modular resources provide greater reliability than centralized resources, even when both have the same forced outage rate. This means that less generating capacity is required for the same level of reliability. These risk-management benefits should be incorporated in the IRP modeling process.

Short-lead-time, modular resources mitigate forecast risk by avoiding the financial costs of overshooting the target demand, as well as the risk that inadequate generation capacity will be available due to delays in the permitting or construction process. This risk is evaluated by applying a probability distribution to the load forecast itself, as discussed above in the load-forecasting section.

Integration Approach

The integration approach differs from traditional integration in several ways. First, the grid-side impacts are explicitly valued at the same time as generation impacts to determine the overall value of specific resources. As mentioned earlier, these vary by both area and time, making the planning exercise more spatial and dynamic. Second, there are more iterations of different combinations of conventional, renewable, and distributed resources to construct a series of portfolios along the efficient frontier with respect to fossil-fuel risk as described in the section above. Third, the results define a probability-density function that allows management to make risk tradeoffs rather than deterministic scenarios.

Summary

The integrated resource planning process is a series of logical steps that build upon each other. Incorporating the full valuation of renewable and distributed resources requires enhancing these steps to incorporate the broad spectrum of benefits and costs. In practice, this requires the incorporation of financial risk management approaches that are highly compatible with the existing planning efforts.

A
COMMENTS FROM HAWAIIAN ELECTRIC COMPANY

Listed below are the Hawaiian Electric Company (HECO) utilities' comments on the report. The report explains concepts on valuing renewable energy and distributed resources that are innovative and visionary to increase the amounts of these resources on the gird. At the same time, these concepts are challenging to apply to actual situations especially on the island grid systems of the HECO utilities. The details of these concepts need to be further worked out to ensure that the reliability and stability of the electric grid is maintained when increasing the level of renewable energy and distributed resources on the grid.

The comments listed below may appear to raise arguments against renewable and distributed resources, but that is not the intent. The intent of the comments is to convey the challenges in the practical application of the concepts so that future work may bring these concepts to fruition.

The HECO Utilities wishes to express its appreciation to Rocky Mountain Institute for sharing their innovative and visionary concepts.

Table A-1
Compilation of Comments

No.	Section No.	Comment
1	General	The impacts of intermittent renewable energy and distributed generation are both positive and negative. The report focuses on quantifying positive impacts (e.g. capacity value) and focuses less on quantifying the negative impacts (e.g. increase in spinning reserve), yet both will need to be understood. Nonetheless, the resources need to be evaluated and the report points out areas to consider.
4	Section 2	Regarding the statement "An excellent example of the relationship between peak load and weather patterns can be found in Hawaii. There, new development and a growing afternoon HVAC demand is change the timing of the peak load.", the HECO utilities, although experiencing higher air conditioning loads, are not expecting the timing of the system peak to change in the foreseeable future.
5	Section 2	The report states that "However, since trades are very reliable, wind power from the trades has the potential to contribute to system reliability." Anecdotal observation on the HECO, HELCO and MECO systems is that trade winds are weak or non-existent during times of higher system load.
7	Section 2	In assessing reliability impact, it is not quite appropriate to compare EFOR of conventional power generators with variability of wind resources. The availability and output capability of conventional generation is well known at any point in time. The variability of wind can be large and is more analogous to the outage or de-rate condition of a conventional generation changing minute-to-minute.

Table A-1 (continued)
Compilation of Comments

8	Section 2	An important characteristic of firm capacity, especially on an island system, is the ability to allow the scheduling of overhaul of other firm capacity units months in advance of the overhaul.
9	Section 3	Examining the correlation of wind speeds and peak loads to assess impact of the variability of wind does not consider the impact of variability during the off-peak due to lower system ramping capability to regulate frequency and the residual frequency deviations that are not mitigated.
12	Section 5	Anecdotal experience at HELCO does not support this statement. Perhaps this statement is relative to the size of the variation, size of the wind farm, the size of the system, and the nature of the wind regime.
15	Section 5	Another driver for operational cost is curtailment during minimum load.
16	Section 5	Report should explain what it takes to set-up, operate and maintain the wind forecasting process that is being suggested and the associated cost.
18	Section 5	Figure 7-3. It is not clear how the combination of a 21 MW wind farm, 17 MW pump storage, and 2 MW battery storage system would provide the same suite of energy services as a 21 MW combustion turbine. They have very different characteristics, which would be applied to different purposes. Among other considerations, the combustion turbine would allow for scheduling of an extended overhaul of another equivalent sized unit and it is not clear how the wind farm, PSH, and BES combination would allow the same given periods of multiple days where wind speeds are low.
19	Section 5	It is not clear the basis for the statement "However, Demand Response can also be used more frequently to manage intermittent variability without interrupting the service that power provides." It is not clear how Demand Response can be used for system frequency regulation on a second-to-second and minute-to-minute time scale. Also, significant number and duration of interruption may have an impact on Demand Response program participation.
21	Section 6	This section appears to draw general conclusions regarding the system benefits of distributed resources based on system benefits of specific cases of distributed resources. There are many different types of distributed resources such as automatically interrupted load, manually curtailed load, Combined Heat and Power, standby emergency generation, as-available generation, utility distributed generation. With the exception of utility distributed generation, the different types of distributed resources could either be controlled by the customer or the utility. The system benefits and potential negative impacts are very different for each case of distributed resources and the system benefits of one case do not necessarily apply to the other. Also, the potential aggregate amount of the specific type of distributed resources would likely be limited, thus limiting the system benefits.
22	Section 6	While it is true at many utilities that lowering the load through distributed resources reduces the reserve margin requirement, it is not necessarily true at the HECO utilities. Being an island utility, the capacity planning criteria of the HECO utilities includes having sufficient reserve margin to handle the unexpected loss of the largest generating unit. So unless the size of the largest generating unit is changed, the reserve margin requirement will remain the same.
23	Section 6	Regarding the statement "while the actual availability of distributed generation is equipment-specific, high technical availability is an inherent per-unit attribute of many distributed generation system", the actual availability of distributed generation is likely more dependent on the proper maintenance of the equipment, rather than equipment type.

Table A-1 (continued)
Compilation of Comments

No.	Section No.	Comment
24	Section 6	Regarding the statement "must-run units are often located within urban centers due to the need for reactive power" and "to the extent that infusing distributed generation – by delivering power when and where it's needed – can help to displace must-run units, this will significantly reduce the system's total operating cost", distributed generation often do not provide reactive power (i.e. use induction generators) and it is also not clear that the potential aggregate amount of distributed generation within the urban center would result in significant displacement of generation.
25	Section 6	This portion seems to imply that there could be a market (i.e. buyers willing to pay, and sellers willing to sell) for load curtailment based on the market experience in California during critical power shortages. It is not clear how this applies to the HECO utilities where the electricity market is not comparable to California. There may be a market for sellers in Hawaii, but the regulatory format would be a challenge to tap the buying market.
26	Section 6	This section discusses using distributed resources at the end of the distribution system and taking advantage of load diversity. This discussion is broad and it is not clear how this would be practically incorporated into resource planning at a system level.
27	Section 6	The statement "thus distributed supply-side and demand-side resources applied at the level where the load factor is worst can most improve distribution asset utilization and can best avoid costly distribution investment" is great in concept, but in practice is difficult to achieve. There are only few cases where low load factor loads drive distribution system expansion, and most occur with short lead times that preclude deployment of distributed resources and still satisfy customer needs for utility commitment to provide electric service. Also, the specific type of distributed resources to be used to address the need for distribution system expansion would be important so that availability in the location, operational characteristics and costs of the distributed resource can also be considered.
29	Section 6	Regarding the statement "there are several distributed generation technologies such as batteries, flywheels, and fuel cells, that can provide regulation energy", it is unlikely that HECO utilities' service area will have aggregate amounts of these technologies in the near future to provide frequency regulation. The ability to dispatch and maintain reliability of numerous remotely located distributed generators to handle second-to-second system frequency regulation would be challenging.
30	Section 6	Regarding the statement "automated load response, with two-way instantaneous measurement and verification, can reduce load in the same time scale as generation, and thereby used to maintain frequency within the control limits", the load would equally have to be able to ramp up quickly in order to provide frequency regulation.
32	Section 6	In discussing the advantage of smaller size and shorter lead-time for distributed generation, the report points out the balancing factor of economies of scale (fueling, operating, and maintaining few sites versus many). There is also the practical issue of limited sites for distributed generation which inherently are in the proximity where people live and work. For example, to displace a 30 MW central station unit would require 30 sites for 1 MW unit. These 1 MW sites, being located in communities, would likely be subject to operating limitations (run-hour limits) which reduce the comparability to central station units.

Table A-1 (continued)
Compilation of Comments

No.	Section No.	Comment
33	Section 6	Marginal Distribution Capacity Cost using area and time specific marginal cost is great in concept. The practical challenge is that the distribution circuits that benefit from this approach are few because these are the circuits where the loads are growing slowly so that the deferral benefits are large enough to offset the cost of the relatively small size of the distributed resource. In addition, the effort to research the area and time specific marginal cost information, and the area and time specific distributed resource information is large relative to the distribution planning staff covering the entire service area. Nonetheless, the HECO utilities have implemented procedures to better coordinate the distribution planning with the DSM implementation and DG/CHP implementation efforts.

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