BULK-POWER RELIABILITY AND COMMERCIAL IMPLICATIONS OF DISTRIBUTED RESOURCES

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1. INTRODUCTION

The electric power industry is currently going through an amazing transformation. For most of its history the electric power industry has relied on ever-larger and more efficient central generating stations. Now, commercial restructuring is sweeping the U.S. electricity industry. Indications are that distributed micro-energy sources may be more prevalent in the future. Three independent forces are driving the trend to small generators:

The electric power industry is being restructured and will become one in which competitive generation suppliers compete for customers, replacing the traditional structure of vertically integrated regulated monopolies with franchise service territories and captive customers.

Natural gas is the fuel of choice for new generation. Twenty years ago, it was illegal to burn gas to produce electricity. Now gas is plentiful, competitively priced, and much cleaner than other fossil fuels.

Technological advances promise to make small-scale generation cost-competitive with large power plants. Efficiency improvements for combustion turbines in the 10- to 100-MW range have transformed them from expensive peaking units to base-load generators with efficiencies above 55 percent when operated as combined cycle plants. More recently, microturbines in the tens-of-kilowatts range are coming to market. Their manufacturers claim that costs will soon be competitive with delivered retail power prices. Internal combustion engines are significantly improved. In the longer term, fuel cells, photovoltaics, wind, and Stirling engines are getting closer to commercial viability. Distributed generation also makes cogeneration possible on a much wider scale, and cogeneration improves the economics of distributed generation and may accelerate deployment.

Combined, these three forces will accelerate the use of distributed generation technologies. In addition, opening markets to competition encourages energy producers and users to seek alternatives to the incumbent utility, including self-generation, storage and load control. Competitive markets also favor technologies that have low capital costs, are quick to build, and quick to deploy, and modular, so that they can respond rapidly to changing market conditions. Major new generation projects that take a decade or more to plan, site, design, and build (those based on coal or uranium, for example) are essentially impossible to finance and build under today's market conditions, whereas abundant gas leads gas suppliers to seek new markets for their product.

The environmental community has been active in the distributed generation field for decades, primarily because many renewable resources are inherently distributed. The aggregated size of the deployed resource has been relatively small, however. Consequently the power industry has been slow to adopt standards, rules and tariffs that fully integrate distributed generation into the overall system, utilize the capabilities of distributed generation to enhance bulk-power reliability, or compensate distributed generators for their contributions to reliability. Restructuring of the industry coupled with the expectation that gas-fired micro-sources are on the verge of a commercial explosion is the impetus behind the recent increase in standards activities that are finally recognizing distributed generation.

This paper examines the reliability impacts distributed resources (DR) can have on the bulk-power systems and the resultant commercial implications. Because the industry is in transition, and the process is a long one, few details can be offered concerning specific tariffs, final interconnection standards, or other regulatory requirements. Politics will continue to play an important role in making these final determinations. The underlying physics of the interconnected power system, on the other hand, is much more constant. This paper discusses the fundamental reliability requirements of the bulk-power system and the interaction with distributed generation.

Distributed resources include distributed generation, energy storage, and agile load* that responds to power system price or control signals. There is no established definition of the maximum size for DR. A common definition includes generating units of 10 MW and less although some include customer-owned generation up to about 100 MW. Electricity is difficult to store directly, so storage is generally in another form as discussed in Exhibit 1. Distributed resources can be owned by a customer (load), a utility, or an independent power producer. Resources (generators or storage) can be located at a customer's facility, at a utility substation, or connected directly to a distribution feeder.

It is important to recognize who owns the distributed resource and what its primary mission is. Distributed resources are often owned by commercial and industrial enterprises in businesses of their own. These owners are not primarily in the electric power business. They can no more turn over control of their facilities to the power system operator than a

*By "agile" we mean customers that can rapidly increase or decrease their loads in response to short-term (e.g., hourly) price changes or to requests from the system operator.

power system can turn over control of the transmission system to a customer. This situation led to the frequent failures of past utility load-management programs. Utilities generally required the customer to turn over control of a portion of the load to the utility, often for a year or longer. The customer received a flat fee independent of how the resource (load reduction) was actually used. This provided little flexibility for the customer and little incentive for it to actually perform. Such inflexibility inherently limits the amount of resource that can be drawn into the market.

Ancillary services do not have a fixed (time invariant) value to the power system, so flat fee payments are not appropriate. As demonstrated by Figure 3, the value of reserves to the power system varies dramatically in time. If that value can be expressed to the DR in the form of a price more resources will be encouraged to provide the needed services. A resource that would lose money providing spinning reserve at an average price of $10/MW-hr might find it profitable to provide the reserve when the price rose above $15/MW-hr. Both the power system and the distributed resource benefit when average compensation is replaced by time varying prices that reflect actual value.

The owners of DR must be free to enter and leave the ancillary service markets at their discretion. Just as the price of hourly energy and each of the ancillary services vary, so do customer economics. For many customers there are times when less flexibility exists and the load cannot be interrupted or generation can not be brought on line without high costs being incurred. These times are often independent of anything happening on the power system and are therefore unrelated to the prices of the energy and ancillary services. This is especially true for the complex interactions between thermal energy, electricity, and the customer's load within a cogeneration facility but it is even evident with simple loads. For the right price, a residential customer might be willing to automatically curtail air-conditioning use for 30 minutes to supply contingency reserves, for example. This same customer would probably be unwilling to curtail use at any price when he was holding a dinner party, however. Similar restrictions might apply for an industrial customer, such as a continuous chemical processing plant while it is taking a monthly inventory and needs a stable process. In both cases the customer choice not to participate is unrelated to the utility economics; neither load is trying to avoid providing the service when it is highest in value. Indeed, the chemical plant may intentionally select times for its inventory when the power system is not stressed, such as at night or on weekends. It would do this not because of a concern for the power system but because that may be a time when the chemical process is stable as well due to reduced activity at the chemical plant.

The power system operator, on the other hand, needs information about which resources will be supplying services ahead of time. The DR operator must declare that it is available before it enters or leaves the market. Perhaps this declaration would be one day in advance for the following 24 hours. Both the utility and the DR will need the ability to change the availability on shorter notice, perhaps with economic consequences. A DR that experiences

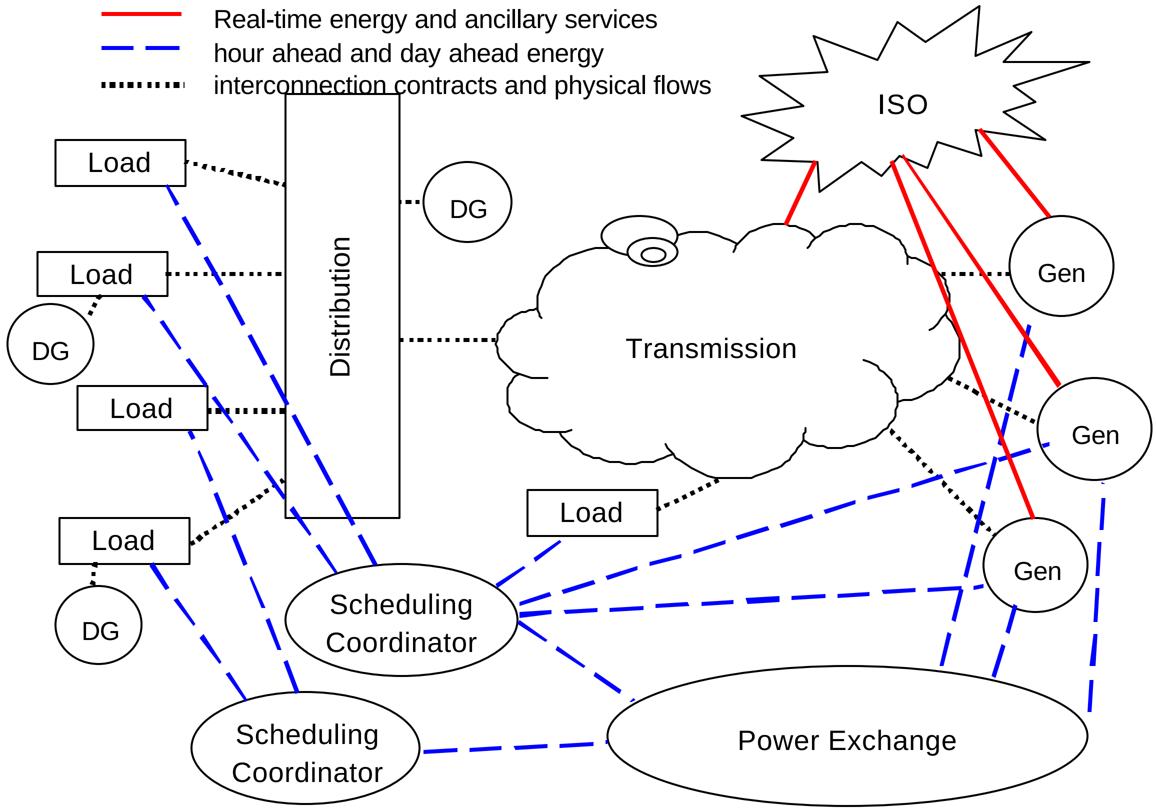

Figure 1 Distributed resources are physically and organizationally separated from the bulk-power system operator and the energy and reliability markets.

technical difficulties and is suddenly incapable of supplying the service must be able to leave the market. Conversely, if the power system finds itself unexpectedly short of reserves it will need to be able to call for additional reserves quickly, perhaps by raising the current price. Indeed, this is how the day-ahead, hour-ahead and real-time markets operate in California's competitive bulk-power system.

It is critical to avoid providing an incentive for a resource (either load or generation) to declare itself available when it is not or vice versa (as was done in the United Kingdom). Equipment failures are inevitable but service providers should have an incentive to maintain the reliability of their resources. They should never find it profitable to sell a service that they know they cannot deliver.

Figure 1 helps explain the difficulties in integrating distributed resources into the bulk-power system. Distributed resources are organizationally and physically separated from the energy and reliability markets. The system operator is used to dealing with the transmission-system facilities and large generators but has generally not had to deal with individual loads or

Exhibit 1. Storage

Electricity is a unique product in that production and consumption occur simultaneously. Storage is attractive but elusive, electric energy is difficult to store directly. Only pumped hydro storage has been commercially viable to date and there installations are limited and costs are high.

In principal storage could have great value. It could be used to arbitrage the daily, weekly or seasonal price fluctuations. On a shorter time scale it could be used to provide contingency reserves, freeing generation to generate. On a shorter time scale still it could be used to enhance power system stability. A number of technologies may be getting closer to providing commercially viable storage: batteries, flywheels, compressed air (coupled with combustion turbines), super-capacitors and superconducting magnetic energy storage are all candidates.

Other forms of storage may be more promising still. If a load can store one of the products it is producing with electricity that load might sell its production flexibility back to the power system as one of the ancillary services. Thermal storage, either of hot water or building cooling, may be a better alternative than directly storing electricity. A customer might oversize its hot water heater. The hot water heater could then be cut off for 15-30 minutes if the power system needed to deploy reserves. The users of the hot water would not notice the interruption. Other potential storage applications include: building air conditioning, process compressed air, municipal water pumping, irrigation, commercial freezers, air liquefaction, or industrial parts production. Any process that consumes electricity, produces something that can be stored at relatively low capital cost, and that is not labor intensive is a good candidate.

Many of these processes naturally cycle on-and-off. Aggregation of numerous loads is necessary to statistically assure a specific response (a specific number of MW) when the power system operator calls for reserve deployment. It is also necessary to control each individual load's return to service. Though there is natural diversity in the cycling of 1000 hot water heaters, for example, they are all likely to try to come on if they have been out of service for an hour. This would impose an unacceptable burden on the power system. The return to service would be staggered to eliminate this burden.

micro-generators[*]. The system operator generally does not even have contact with

[*]We use the term "system operator" and "independent system operator (ISO)" to identify that function within the regional transmission organization that controls the operation

organizations that own distributed resources. Communications, metering, and control infrastructure is required. Contracts and tariffs are needed. Rules and standards that define each party's responsibilities must be developed. First, regulators and engineers responsible for designing the system must be convinced that the distributed resources are willing and able to participate in reliability and energy markets.

Distributed resources *should* be permitted to participate in reliability markets. The relatively small size of each individual unit benefits the power system because the failure of a single unit to respond has relatively little impact on the power system. Small units are likely to respond faster than large units, providing another benefit.

Communications, control, and metering issues remain problematic. System operators are used to dealing with a relatively few, large generators to obtain reliability resources. Because they are few and large it is reasonable and necessary to closely monitor the real-time performance of each unit*. It is necessary because the failure of a single unit to perform as expected has serious consequences that must be dealt with immediately. It is reasonable because the amount of information is small enough that the system operator can make use of it in real-time. Also, the cost, on a per-MW basis, has proven to be acceptable. These characteristics are challenged by distributed generation. With thousands of small resources responding it is not necessary for the system operator to monitor the performance of each unit in real-time because the failure of a single resource is inconsequential. The performance of the aggregation can be modeled statistically with high confidence. It is not reasonable either because the amount of information that would be returned would overwhelm the system operator. The cost would be prohibitive as well. Unfortunately, with little experience to base requirements on there are no standards for communications, control or metering yet.

Distributed generation and agile load are surprisingly similar from the point of view of power system reliability. Reliability is maintained on the power system by continuously balancing load and generation. Historically this has been done by controlling a few large generators but it does not have to be done that way. The important thing is to balance load and generation, which can be done with either side of the equation. Distributed generation and agile load share the advantages and disadvantages that come from being composed of numerous small resources. Reliability and response speed should be higher, but communications and metering are more difficult and expensive.

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of the power system.

*Unit real and reactive power output and bus voltage are typically reported to the system operator every two to eight seconds.

Some distributed generators exploit resources that are inherently dispatchable (controllable) while others are not*. Intermittent resources, such as wind mills, photovoltaics, or run-of-the-river hydro, are not dispatchable. Cogeneration facilities with specific thermal requirements may not be dispatchable either. The ability to control the output of dispatchable generators has value in that the generator can support the bulk power system. This increases the number of services (e.g., regulation and spinning reserve) the generator can sell to the power system. Distributed generators that interface with the power system through solid-state invertors (rather than through rotating generators) can sell reactive power to the power system whether the generator is providing real power or not.

Because this report focuses on bulk-power reliability, a number of benefits offered by distributed resources are not discussed. Distributed resources can be used to reduce the loading on distribution equipment and delay the need for the distribution utility to make costly investments. They can also provide emergency power, increase local reliability and improve local power quality. Waste heat can be used for cogeneration, an option not open to central generators. These benefits, although not discussed here, should be examined when considering distributed-resource investments.

The rest of this report is organized as follows. Section 2 discusses the reliability services that distributed resources may be able to sell. Section 3 examines the communications, control, and metering requirements for providing these services. Section 4 looks briefly at interconnection requirements, standards activities, and utility concerns associated with distributed generation. Section 5 discusses transmission concerns for distributed resources. Section 6 presents a vision of how a distributed system could work in the future. Section 7 summarizes the key points developed here.

2. TECHNICAL REQUIREMENTS FOR BULK-SYSTEM RELIABILITY SERVICES DISTRIBUTED RESOURCES MIGHT CHOOSE TO SELL

Electricity is a unique commodity in that production and consumption must be matched essentially instantaneously. Reliability of the power system is maintained by actively controlling some resources to continuously balance aggregate production and consumption. Historically control was exercised only over large generators. Loads did whatever they wanted

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*Dispatchable resources are ones for which the RTO can order increases or decreases in output, within a minute or two for resources providing the regulation service or within five or ten minutes for resources providing balancing services (i.e., the load-following service). Intermittent resources, because their output depends on external forces (such as the wind or sun) are not dispatchable and, therefore, can not sell controllable generation into ancillary service markets.

to meet their needs, while generation, under the control of the system operator, responded to the changing requirements imposed by loads. As restructuring progresses and regulated system operations is separated from competitive generation, the specific requirements for reliability services to maintain this generation/load balance need to be articulated clearly in technology-neutral language. That is, the required performance must be specified clearly enough that separate commercial entities can agree on what will be provided, and at what price. The requirements must specify performance rather than the methods to yield desired outputs. For example, a system operator should request "100 MW of response that can be delivered within 10 seconds" rather than "100 MW of unloaded, on-line capacity from a large fuel-burning generator". FERC started this process by requiring the separation of six ancillary services from transmission in its Order 888; FERC expanded that process with its Order 2000 on regional transmission organizations (RTOs).

INDIVIDUAL SERVICES

Table 1 presents 8 ancillary services (reliability services) that DR owners might want to sell*. These services are required to maintain bulk power system reliability and are being opened to competitive markets in regions where RTOs operate. Distributed generators and storage devices may or may not be able to sell Reactive Supply and Voltage Control From Generation to the bulk power system depending on their size and location. Network Stability is a services that distributed generators and storage devices should excel at if they are connected to the power system through an inverter and are in the correct physical location. Blackstart appears to be a service that DR is qualified to sell since many DR generators are inherently capable of operating independently of the power system. To be useful to the power system, however, the blackstart units have to be located where they can be used and capable of re-starting other generators. Some DR generators are not large enough or located properly to be useful. For those that are big enough and in the correct location this could be an excellent service to sell.

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*This list is not exactly the same as FERC's. System Control is not included because DR owners can not sell that service. System Blackstart, Backup Supply and Network stability are included because DR owners might be able to sell these services even if FERC does not explicitly recognize them.

The services also do not exactly match the current NERC Interconnected Operations Services which currently split out Frequency Responsive Reserve. The precise definitions are still in flux though the concepts are well accepted.

Table 1. Key Ancillary Services and Their Definitions

Reactive Supply and Voltage Control from Generation: Injection and absorption of reactive power from generators to control transmission voltages
Regulation: Maintenance of the minute-to-minute generation/load balance to meet NERC's Control Performance Standard 1 and 2
Load Following: Maintenance of the hour-to-hour generation/load balance
Frequency Responsive Spinning Reserve: Immediate (10-second) response to contingencies and frequency deviations
Supplemental Reserve: Response to restore generation/load balance within 10 minutes of a generation or transmission contingency
Backup Supply: Customer plan to restore system contingency reserves within 30 minutes if the customer's primary supply is disabled
Network Stability: Use of fast-response equipment to maintain a secure transmission system
System Blackstart: The capability to start generation and restore all or a major portion of the power system to service without support from outside after a total system collapse

The five remaining services (Regulation, Load Following, Frequency Responsive Spinning Reserve, Supplemental Reserve, and Backup Supply) deal with maintaining or restoring the real-energy balance between generators and loads. These services are characterized by response time, response duration, and communications and control between the system operator and the resource needed to provide the service. Figure 2 shows the required response for these five energy-balancing functions. Because regulation requires continuous (minute to minute) adjustment of real-power transfers between the resource and the system, loads may not want to provide this service. Load following could be provided directly or through the use of a spot market price response on a time frame less than an hour, consistent with FERC's requirements that RTOs operate real-time balancing markets. The contingency reserves are especially amenable to being provided by distributed resources.

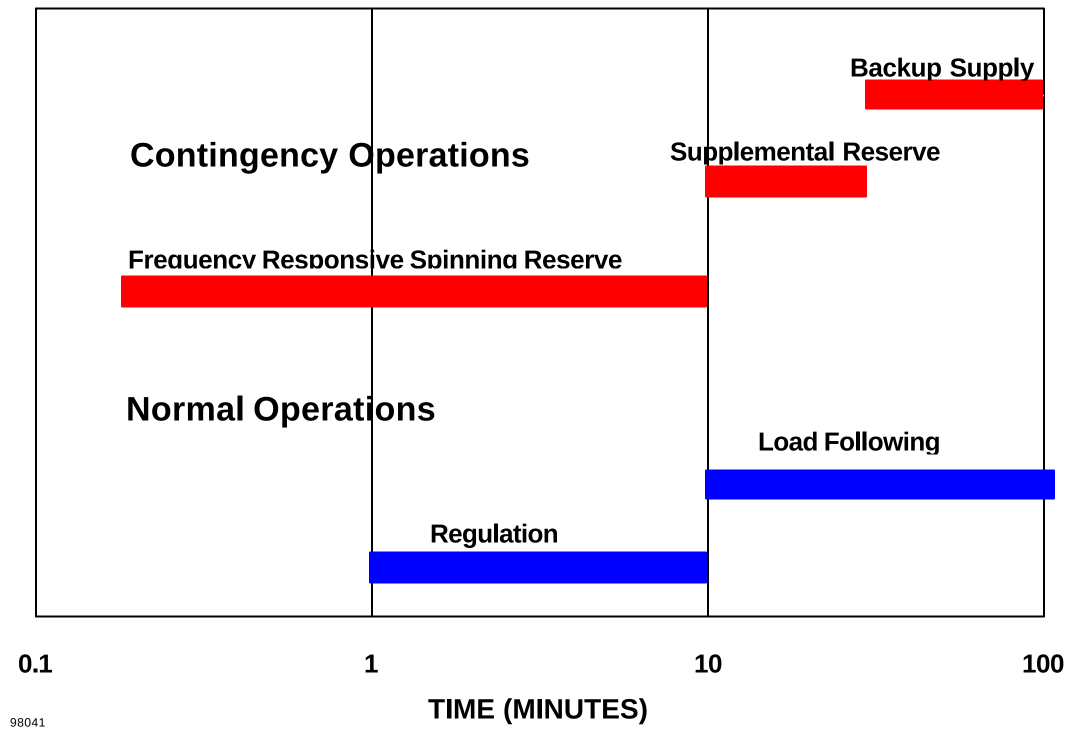

Figure 2 Real-power ancillary services are differentiated by the required response time and duration.

Similar restrictions apply to DRs supplying ancillary services as apply to central generation stations supplying those same services. For a generator to supply contingency reserves, it must have capacity available to respond to the contingency; the generator cannot be operating at full load. Similarly, a DR selling contingency reserves must have capacity it can make available when the contingency occurs, either by increasing its power output or by temporarily curtailing load.

Providing ancillary services from distributed resources should involve a careful integration of generation and load response. Since fast services generally command higher prices than slower services (as shown by Figure 3) it is desirable to sell the fastest service possible. At times it may be faster to temporarily curtail load than to start generation. Load can be restored to service as additional generation is brought on line. It is also generally easier to incorporate energy storage on the load side in the form of thermal storage than it is on the power-supply side. Ten minutes of storage can be very valuable, as seen from the high prices paid for spinning reserves in Figure 3.

DISTRIBUTED RESOURCES AND THE POWER SYSTEM BENEFIT WHEN ANCILLARY SERVICE MARKETS ARE OPEN

Distributed resources benefit because they receive revenue from the sale of ancillary services as well as from energy production. The power system benefits in several ways.

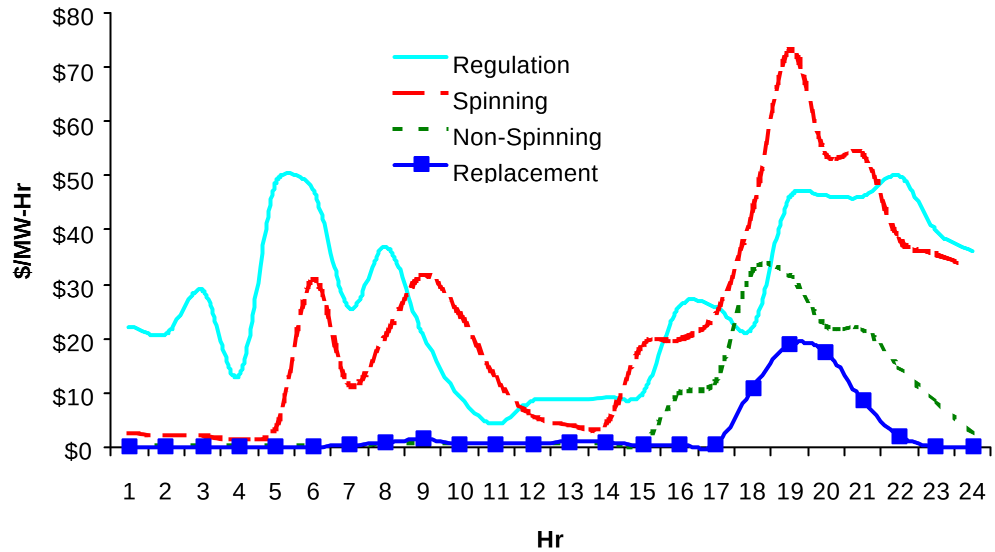

Figure 3 Real power reserve services requiring faster response command higher prices, on average, than do slower services in the California market as shown by this December 1998, weekday data.

FERC is encouraging open competitive markets for generation, both energy and ancillary services. FERC ordered the unbundling of ancillary services from transmission to promote competitive markets, which should improve economic efficiency and lower electricity prices. These markets should be open to any technology capable of providing the service, not just generators. This will expand supplies and reduce horizontal-market-power problems.

Beyond the argument of fairness, having additional resources participate as suppliers, as well as consumers, of electricity services improves resource utilization. Ancillary services consume generating capacity. When loads provide these reserves, generating capacity is freed up to generate electricity.

Smaller facilities will probably respond more quickly to control-center requests than large generators. This will likely more than overcome the communications and control delays associated with their greater numbers. Distributed resources should also be a more reliable supplier of ancillary services than conventional generators. Because each facility will be supplying a smaller fraction of the total system requirement for each service, the failure of a single resource is less important (Exhibit 2). Just as a system with ten 100-MW power plants requires less contingency reserves than one with a single 1000-MW plant so too a system that utilizes a large aggregation of DR as a resource to supply reserves will require less redundancy

Exhibit 2. Reliability from Distributed Resources

Whenever a system operator calls for the deployment of contingency reserves there is always some change that the resource that is supposed to supply the reserve will fail to do so. The small size of individual distributed resources reduces the consequence of this problem and makes them a more reliable source of contingency reserves. Take, for example, the case of a system operator purchasing 100 MW of supplemental operating reserve from a 100 MW fast-start combustion turbine. This turbine might start within the required time on 90% of its attempts. In one case in ten the system operator is 100 MW short. It does the system operator little good to reduce its expectations to 90 MW, though that is the average response.

A collection of 12,500 10 kW distributed resources that individually have only an 80% chance of responding each time makes a better aggregated resource. In this case 20% of the individuals fail to respond but the system operator still sees a the full 100 MW response each time.

than one that carries all its reserves on a few large generators. There can still be common-mode failures in the facilities of the aggregator (the aggregators communications system could go down, for example), but it is easier and cheaper to install redundancy in this portion of the system than with an entire 1000-MW plant.

PROVISION OF INDIVIDUAL SERVICES

The owner of a DR, in cooperation with an aggregator and the system operator, would determine the amount of each service that could be provided. Metering, communication, and control requirements would then be established.

Looking first at the services required to restore the generation/load balance after a contingency, ***Supplemental Reserve*** is a likely candidate for provision. The resource must fully respond within 10 minutes of the contingency[*]. Response must be maintained for an additional 20 minutes, i.e., until 30 minutes after the contingency. This is a short interruption that many customers may find acceptable for a portion of their load. Integration of distributed generation with load is particularly important. Anything that inherently has some storage in the process, or any process for which storage can be readily added is a good candidate.

[*]Specific timing requirements for each service vary from region to region. The requirements referenced here are from NERC (1998) Draft Policy 10. The NERC Security Committee is currently thinking of extending this 10 minute response time to 15 minutes.

Candidates include water pumping, building temperature control, water heaters, and air compressors. A commercial building might sell Supplemental Reserve by offering to shut off its air conditioning compressors. Building temperature would rise a few degrees during the curtailment. The building owner might pre-cool the building a few degrees in order to store “cool” and limit the temperature rise to an acceptable value. Alternatively, the building could be designed with greater thermal mass, either in the structure itself or as a thermal storage unit attached to the building ventilation system.

The system operator takes some of the 10 minutes to recognize the contingency and to call for response. The aggregator’s communications process will consume some time. This leaves a few minutes for the distributed resource to respond.

Frequency Responsive Spinning Reserve is both easier and more difficult for DRs to provide. Because the service responds to system frequency, each facility has the triggering signal available at all times. The service only has to be provided until it is replaced by Supplemental Reserve, 10 minutes, creating a shorter interruption. Full response is required within 10 seconds, however, which may make it hard for generation that is not on-line to provide. Again, an initial response by the load, followed by a response from the generation might be ideal. NERC is beginning to move away from technology specific standards as indicated by the recent Performance Committee meeting. Don Badley (Northwest Power Pool) reports that “they were in agreement that load could be counted as Spinning Reserve but only as long as it approximates governor response”. Having each facility in an aggregation responding at slightly different frequencies could create a typical generator governor characteristic where the response is greater with greater frequency deviation.

Frequency Responsive and Supplemental Reserves restore the system’s generation/load balance and maintain it for 30 minutes. Thirty minutes after a contingency occurs the customer that lost the generation that occasioned the use of reserves is responsible for making other arrangements or curtailing its load. The ***Backup Supply*** plan is a pre-arrangement that tells the system operator how to proceed for each load’s loss of primary supply. Loads may find distributed generation an attractive option instead of relying on Backup Supply delivered through the utility. Alternatively, some distributed resources may find it attractive to provide Backup Supply for other loads. The 30-minute warning provides time for communications and for the responding facility to take actions to reduce its own costs.

Distributed resources may also wish to participate in maintaining the generation and load balance during normal operations, though this seems less likely. ***Load Following*** could be provided by cycling daily operations in response to direct MW commands from the system operator or by responding to short-term price signals.

Regulation is the least likely of the generation/load balancing services for DRs to provide. It requires the most frequent response by the DR to system operator requests, typically more than one per minute. It also requires the greatest amount of communications between the DR and the system operator. Not surprisingly, standards for the required communications, control, and metering have not been established. It is possible, however, that excess agile generating capacity or loads with variable speed drives (e.g., water pumping) could accept automatic-generation control signals from the system operator. Municipal water pumping accounts for approximately 1% of national electricity consumption, providing potentially significant sources of load-based regulation or other ancillary services.

3. COMMUNICATIONS, CONTROL, AND METERING REQUIREMENTS

Historically system operators have obtained ancillary services from a few large generating plants. Because of the small number and large size of each resource it was both necessary and practical for the system operator to monitor the performance of each plant closely. Generator power output is typically telemetered to the system operator every two to eight seconds. Commands to adjust output can be sent to the plants as frequently. This high-speed communication is necessary because the failure of a single power plant to respond had to be compensated for immediately. It was practical because each plant was very expensive and the communications and control costs, although high, were small in comparison to the overall cost of the power plant. It is probably not cost effective to provide this level of monitoring for each DR. It is also not necessary, as will be discussed later.

Once the commercial arrangements are understood the actual information that must pass between the parties follows from the service requirements. For each of the reliability services, a method must be implemented to transmit the price to the resource and for the resource to confirm its commitment to provide the service. This can be done a day ahead or hour ahead. For services, such as blackstart and voltage control, this may be done through long-term contracts of one or more years in length.

Actual deployment requires much faster signaling. *Frequency Responsive Spinning Reserves* must be fully deployed within ten seconds. Resources responding to Interconnection frequency deviations can detect on their own without information from the system operator, because system frequency is the same everywhere and is readily observable. Spinning reserve is also used by the system operator to respond to contingencies that are not large enough to move system frequency. The request to deploy these reserves must get from the system operator to each resource within seconds. Fortunately this is a “broadcast” signal, a unique signal is not required for each responding resource. Also, the signal can be fairly simple, “deploy now”, rather than a complex command to follow a detailed list of instructions.

Deployment of *Supplemental Reserves* is similar to deployment of Frequency Responsive Spinning Reserves but simpler. Since response is not required for 10 minutes the signal can take longer to get from the system operator to the resource, perhaps a minute or so. The signal is still a simple broadcast one telling a large group of resources to deploy.

Backup Supply has a longer time still for the deployment signal to get to the resource but it likely involves more commercial parties than the two reserve signals. It is also likely to be more resource specific because it is a contractual matter between the customer that lost its primary supply and the resource supplying Backup Supply. If a customer is using distributed generation to provide its own Backup Supply the communications and control issues, as well as the commercial arrangements are much simpler.

Load Following requires signals sent every five or ten minutes. These signals could either be prices, which could be broadcast throughout the system, or specific MW instructions, depending on how the service is defined in each area. In either case, the signal would likely be sent several minutes before the price or instruction was to be implemented and could take in the range of one to three minutes to arrive.

Regulation requires matching generation and load on a minute-to-minute basis. Deployment instructions tell the resource to go to a specific level (almost always a generation output level but conceivably a load consumption level). These instructions must arrive within seconds to be effective.

Reactive Supply and Voltage Control from Generation is generally deployed by sending the resource a voltage or reactive power output setpoint. The resource is expected to respond rapidly to local conditions that attempt to move the resource away from its setpoint. But setpoint updates are not sent very often and can typically withstand a delay of a minute or two. Signals are resource specific, however, because they apply to the particular physical location.

Blackstart requires intimate control by the system operator. Deployment is extremely rare, however, so it is possible that voice communications with a local operator would be acceptable if the resource was at a manned facility with suitably trained operators.

CERTIFICATION VS METERING

Metering serves two purposes. Coupled with fast communications it can provide the system operator with information concerning the real-time performance of the resource in providing whatever ancillary service the resource is currently supplying. Coupled with much slower communications it can also provide after-the-fact information on how well a resource performed each service it was contracted to provide. Communications speed is most important for the first task, accuracy for the second.

Most of the generators on a typical power system are relatively large and expensive. It is reasonable for the system operator to monitor unit output and bus voltage every few seconds. The amount of data and the expense per MW are both reasonable. When the operator calls for response, it can be monitored in real time. Historically, real-time monitoring of generator provision of ancillary services was emphasized, little attention was paid to after-the-fact performance evaluation within vertically integrated utilities.

Providing the same real-time information from hundreds or thousands of individual resources (e.g., residential water heaters) would be prohibitively expensive and would yield an overwhelming amount of data that could not be managed in real time. An alternative to real-time monitoring of each individual resource exists. Distributed resources could be certified, either individually or in aggregate, for the provision of each ancillary service. Certification would consist of deploying the resource under controlled conditions to determine the reliable response. Testing of the contingency reserves, for example, would not be announced to the resource. The response would be measured on control-area metering. Periodic testing would monitor continued capability. Individual resource performance would also be monitored with recording meters. After-the-fact analysis, and payment for service provision, would be based on recorded system operator requests for response and resource service provision. There is no compelling time constraint on returning the verification information to the system operator, it could be collected at the end of the billing cycle (monthly) as long as the meter preserves enough detail in the temporal record to evaluate the performance. The metering has to be fast enough to capture ancillary service performance but the communications from each resource to the system operator does not. This should keep the cost to participate in ancillary service markets reasonable.

It may take time to convince system operators that are used to directly monitoring their ancillary service resource's performance in real time that the use of DR is better. Assured response from a certified resource that, because of the small size of each component, is inherently more reliable and which fails more "softly" provides greater overall reliability than closer monitoring of a less reliable resource[*].

AGGREGATION AND COMMUNICATION

The major objection often voiced to distributed supply of ancillary services is that the system operator cannot deal with the large number of individual resources and that the communications requirements would be overwhelming. These are valid concerns but ones that can be addressed. Aggregators can provide a genuinely valuable function here. By handling the communications with a large number of distributed facilities they can present the system

[*]Failures are "softer" in that not all of the response is lost at once, as is typical with large generators. Failure of a single DR has relatively little impact on the overall system.

operator with a single point of contact for a reasonable amount of capacity, similar to the system operator's interface with generating resources. They can also be an interpreter between the electrical system and customers. The system operator is not interested in learning the details and concerns of each customer. Similarly, customers are in businesses of their own and have neither the time nor the interest in learning all about the power system. The aggregator can bridge this gap, creating a valuable resource in the process.

The aggregator would first perform the commercial function of identifying DRs that are interested in and capable of participating in ancillary service markets. The aggregator would determine the collective capability to provide each ancillary service and negotiate with each DR to determine what they would be willing to provide at any given price. Armed with this information the aggregator would negotiate with the system operator to be able to supply ancillary services to the system. This could be as simple as filing the appropriate paperwork to register for an existing ancillary services market. It could be as complex as convincing the system operator of the value of letting DR participate and establishing performance rules. Negotiations between the aggregator, the system operator, and the DR owners would be iterative.

The aggregator would establish physical communications with the system operator that likely will have to conform system control and data acquisition (SCADA), energy management system (EMS), and/or automatic generation control (AGC) requirements established by the system operator. These communications will enable the system operator to treat the DR aggregation as a single resource. Next the aggregator will establish a communications network to connect it to each DR. The communications between the system operator and the aggregator will be robust and fast. The communications between the aggregator and each DR will be inexpensive. Both price signals and deployment control signals will have to be conveyed.

The aggregator also performs important real-time decision functions as well. Interacting with the ancillary service markets the aggregator negotiates price and quantity commitments for the aggregation. This involves the expected interaction with the ancillary service markets of providing bids. To generate those bids the aggregator has to negotiate with each DR. It can do this by having a list of standing bids from each resource, by communicating with each resource in real-time to determine current capability and price, or through a combination of both. The aggregator will have to assemble the collection of DR capabilities into a coherent ancillary service bid for each market clearing, perhaps hourly. It is likely that the aggregation process will involve some manual decision process and communication with the ancillary service markets. Communication with each DR to obtain current capability and price information will likely be automatic, though it must be under the control of the DR owner. It could be as simple as the DR owner providing a standing bid for each ancillary service that changes only when the DR owner notifies the aggregator (the standing bid is "automatic"). Or it could be as complex as a computer program at the DR facility that considers all the current conditions at the DR facility and generates a quantity and price bid in real-time. Finally, on the commercial side, the aggregator must notify each DR of commitments that resulted from each round of market clearing.

The aggregator has an important operational role as well. When the system operator call for deployment of an ancillary service it notifies the aggregator. The aggregator must pass this notification on to the individual Drs that agreed to provide the service for the current period. If the system operator called for less than full deployment the aggrgator must be capable exercising control over the collection of resources. For example, the aggregator may have sold 400 MW of supplemental operating reserve. When a need arises the system operator may only call for 300 MW to be deployed, however. The aggregator could tell each DR to provide only ¾ of what it offered. Alternatively it could tell ¾ of the DRs to deploy. A combination of the two methods will likely be used depending on the current capability of each DR.

The aggregator may be the entity that takes the risk of statistical performance when load is used as the resource. When cyclic loads, such as hot water heaters or air conditioners, are used as contingency reserves there is some probability that any given load will not be on when it is directed to turn off. Use of cyclic load as a resource requires an evaluation of the statistical behavior of those loads to determine how many loads to curtail in order to obtain a specific response. The response will vary as external conditions vary. Many more hot water heaters are likely to be on in the morning when people are waking up, getting ready for work, and using hot water than are on in the middle of the night when little hot water is used. The aggregator will likely be the one to make the real-time evaluation of what DR response to request from its fleet of resources in order to deliver a specified response to the system operator. The aggregator will also likely be the one to take the economic risk of non-performance[*].

The aggregator will also be heavily involved with individual DR performance evaluation and compensation. Compensation for the aggregated response will be based upon the market rules established for all ancillary service providers. How that total compensation gets allocated among the individual DRs will be the responsibility of the aggregator. Individual DR performance will have to be evaluated. Metering at each DR site will record individual response and report this back at the end of the billing cycle, perhaps monthly. Individual meters may record deployment requests as well as DR response to assure that the communications system notified the DR that it needed to deploy. Compensation could be per successful event. Alternatively, performance metrics that establish statistical limits might be preferred. Performance might only be expected 1 out of 2 times for a cyclic load, for

[*]The system operator could take the risk instead of the aggregator. In that case the system operator might contract for X MW of hot water heater response rather than for Y MW of supplemental operating resereve.

Exhibit 3. Metering an Aggregation

An example may help to illustrate how recording meters can differentiate aggregator performance for the system operator. Say a system operator has 4 large generators (A, B, and C) and 3 aggregations (X, Y, and Z) each providing 50 MW of supplemental operating reserve. A contingency event occurs and the system operator calls for 300 MW of response. From system metering the system operator can tell that it received only 250 MW of response. The system operator takes immediate action to obtain additional response, perhaps obtaining it from a neighboring system. Who failed to deliver? The large generators individual real-time metering may have shown that generator A over-delivered 10 MW while generator B under-delivered 20 MW. Generator C delivered what it said it would. The system operator then knows that collectively, aggregators X, Y, and Z under-delivered 40 MW but it is not possible to tell from the real-time metering where the fault lies. Examining the individual DR recording meters at the end of the month would reveal the source of the problem. Aggregator X could prove that it fully delivered its 50 MW based upon its DR's meters. Similarly aggregator Y could show that it delivered its 50 MW. Aggregator Z would have to admit that it delivered only 10 MW based on its DR's meter readings. Aggregator Z would also know which of its DRs failed to perform, but this is an internal matter for Aggregator Z. Note that the system operator does not need to actually collect and analyze the individual DR meter data. It is enough for the system operator to have the right to audit the meter data in the event that there is a dispute among the aggregators.

example. Metrics and compensation would be a commercial concern between the DR and the aggregator.

Individual DR meter records may be used by the system operator to evaluate the performance of each aggregation. System metering tells the system operator in real time how the entire system performed for each ancillary service deployment. Individual metering on large resources tells the system operator how they contributed, again generally in real time. Since it is impractical to provide real-time metering and communications to report DR performance the system operator has no way of distinguishing between individual aggregators performance. Examining each individual DR's recording meter will enable the system operator to evaluate the performance of each aggregator, as shown in Exhibit 3.

COMMUNICATION TECHNOLOGIES

NERC policies call for reliable and redundant communications networks for "voice, AGC, SCADA, special protection systems, and protective relaying". Historically utilities have used a range of technologies to fulfil this requirement to observe and control the transmission system and communicate with generators. Microwave, fiber optics, leased telephone lines, owned telephone lines, and power line carrier are all in common use. All can provide reliable and fast, communication for data, control, and voice signals. Specifically, the draft NERC policy that deals with ancillary service resource providers (Policy 10) calls for "voice and data communications ... to respond to the instructions or controls of the OPERATING AUTHORITY" and for the resource to "provide to the OPERATING AUTHORITY real-time telemetry of the real power output of each IOS RESOURCE." Unfortunately traditional utility communications technologies are too expensive for use with DRs though they work quite well for large generators.

Several technologies look appealing for low-cost communication with a large number of distributed resources, however. Pilot efforts are underway using pagers, the Internet, non-dedicated phone lines, and radio. In each case the objective is to reduce the per-unit cost of implementation. Communication speed is important but only has to be fast in one direction, and the fastest signals generally can address a large group of resources with a single deployment command.

Pagers, for example, are promising because they provide individually addressable communications for $20 capital cost and $5/month per device. The amount of information they transfer, a telephone number and short text message, is greater than that required for an ancillary service transaction which typically contains a MW amount and a price. Deployment signals contain even less information, a MW amount at most. Pagers are limited to communicating in one direction, from the aggregator to the individual DR, so they would be useful for confirming a DR's acceptance to supply an ancillary service for a set time period and for deployment commands. Pager speed appears to be adequate or close. Messages typically get to pagers within about two minutes, quite adequate for most ancillary service communications. The pager service provider is constantly assembling batches of messages for broadcast to all pagers. This is the process that results in the slight delay in the communications process. It is possible that the infrequent ancillary service deployment commands for spinning reserve (the ones requiring the greatest speed) could be given higher priority for a higher fee. Pager based thermostats are currently available for a few hundred dollars. Prices should drop significantly if quantities increase. And quantities would have to be high for the resource to be ov value as a DR.

Non-dedicated telephone lines can be used as well. Devices such as alarm systems and even some advanced electric meters use existing telephone circuits to communicate with central stations. The device accesses the existing phone line, determines if it is currently in use, and makes a phone call to the central station when communications are needed*. This type of technology could be used when a DR needs to communicate a change in availability to the aggregator.

Locations with Internet access may choose this technology to communicate with Drs. Individual lighting fixtures are being experimentally addressed through this technology in some office complexes. Costs are expected to be as low as $1/device. Communications is available in both directions.

The resource aggregator will deploy its own communications network and sell the aggregated performance, which depends in part on the performance of the communications network. This gives aggregators the freedom to try different communications technologies and the incentive to find performance at low cost.

4. INTERCONNECTION REQUIREMENTS & UTILITY CONCERNS

Interconnection requirements affect both power plants built by independent power producers and distributed resources. In both cases, owners of new resources complain that the traditional utilities are blocking their access to the bulk-power system by imposing expensive and unneeded studies and investments. The utilities respond that they must ensure the safety of their workers and the public in general, and that they can't connect resources whose operations might degrade power quality, reduce reliability, or overload transmission elements and cause congestion.

The situation for DR is especially difficult because utilities have relatively little experience connecting distributed generators. The requirements in place at many utilities today are based on good practice for large units. They often require individual engineering studies for each application. Capital costs associated with interconnection equipment can be $40,000 or greater. While this can be appropriate for a 100-MW generator it is prohibitively expensive and probably unnecessary for a 2 kW photovoltaic system.

Utilities have three basic interconnection concerns:

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*Alarm systems typically seize the phone line to report emergencies. Electric meters typically wait until the phone line is not in use. Some electric meters even sense when another telephone on the premises is picked up and terminate the meter's phone call to avoid interfering with a new outgoing call.

- # *Safety* - A distributed generator could energize part of the distribution or transmission system when that system is supposed to be de-energized., endangering utility personnel and the general public.

- # *Equipment Damage* - A distributed generator could damage utility or other customer equipment.

- # *Power Quality* - A distributed generator could cause flicker, harmonics, or other power-quality problems for other nearby customers.

These underlying concerns manifest themselves in numerous technical requirements such as the need for load break disconnects (a switch located outside the building so that utility personnel can disconnect the distributed generator at any time), utility-grade breakers (more rugged and expensive than commercial breakers), dedicated isolation transformers, feeder relay coordination (studies are required to assure that existing protection on the utility system will continue to work after the distributed generator is installed), etc. Finding appropriate ways to deal with these legitimate concerns has lead to considerable debate over interconnection requirements. Utilities have little financial incentive to find low-cost solutions and often feel that they are the ones taking the risk. Manufacturers and owners of DR want to reduce costs but do not want to sacrifice safety or quality.

State regulators are beginning to resolve these issues. The Texas Public Utility Commission has taken a lead in this area implementing interconnection standards for the state. Texas experienced a generation shortage in 1998 and the Commission believes that existing distributed generation, such as emergency generators at customer facilities, can alleviate the problem.

INTERCONNECTION STANDARDS

Standards activities are also underway at the Institute of Electrical and Electronics Engineers (IEEE) and Underwriters Laboratories. These are voluntary standards but state regulators and utilities often adopt them so the forums are important. IEEE P929, *Recommended Practice for Utility Interface of Photovoltaic Systems*, addresses interconnections for small (less than 10 kW) photovoltaic (PV) systems with the utility grid. The recommended practice has several key features:

- Interconnection requirements apply only to the interface point between the utility and the customer, not to the point where the generator connects to the customer's facility.

- If the inverter is non-islanding, it is not a possible source for energizing the utility. No protection is required beyond that internal to the inverter.*
- The inverter should shut down if voltage is outside 88 to 106 percent of nominal or frequency is outside the range 59.5 to 60.5 Hz.
- Required trip times vary from 2 to 120 cycles; with faster tripping required for greater deviations from normal operations.
- The inverter should remain off until at least 5 minutes after utility power is restored.
- Third-party testing is required. Underwriters Laboratories test procedure UL 1741 supports the requirements in P929.

Underwriters Laboratories developed UL 1741, *Invertors and Charge Controllers for Use in Photovoltaic Power Systems*, to coordinate with IEEE P929. This standard (its first draft was released 15 years ago in 1984), covers testing, manufacturing specifications, and general safety for PV invertor and charge controls. This standard provides for third-party testing and certification of manufactured PV distributed generation systems.

The standards work for small PV systems is being extended to all distributed generators (less than 10 MW) through IEEE SCC 21 P1547, *Distributed Resources and Electric Power Systems Interconnection*. This is the primary national forum for distributed generation manufacturers, utilities, and others to come to consensus concerning technical requirements for interconnection. The process is expected to result in a final draft standard by the spring of 2001.

Standards activities concerning distributed generation interconnection tend to be slow because this is a consensus building activity among parties with very different motivations. While everyone wants safety and reliability distributed generation manufacturers and owners have a strong economic motivation to keep costs down, to standardize the process, to reduce uncertainly, and to speed the interconnection process. The utilities tend to focus more on assuring continuity of service to other customers and reducing the cost of the overall utility system. Utilities tend to favor studying each installation and are less likely to agree that a generic solution is adequate in all cases. Finding common ground is taking time.

WHEN TO DISCONNECT A RESOURCE

The issue of when to disconnect a distributed generator illustrates the difficulty in deciding how best to utilize DR. It is universally recognized that a distributed generator must not energize a section of the power system that the utility has intentionally de-energized. This

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*An inverter is a solid-state electrical device that converts DC electricity into AC electricity. An electrical island is a portion of the electrical grid that operates independent of the rest of the grid (i.e., it has its own frequency).

would risk injuring or killing people. But should DR be able to intentionally power a portion of the grid independent of the host utility (islanding)? Most proposed standards do not allow such islanding although it is not an uncommon practice for utility owned generators. Utilities are concerned that non-utility generators might not do this safely, other customer's equipment might be damaged or that power quality would not be acceptable.

Similarly, proposed interconnection standards now call for distributed generators to disconnect from the power system if frequency or voltage get out of a narrow range. This is advocated to simplify the power system until it is returned to a more normal condition. It is also a safety feature to assure that the distributed generator is not operating in an island. But if frequency is low, removing generation further lowers frequency, which hurts the system, possibly causing it to fail. This separation requirement is now being re-thought.

OPERATING MODES

A surprising amount of flexibility remains even if safety concerns prevent operating distributed generation interconnected with the grid. Some or all of a customers load can be transferred to an isolated generator, relieving the utility of the burden of supplying that load. This is the normal operating mode for emergency generators. One disadvantage of this mode is that some finite time (seconds) is generally required to switch from the utility supply to the distributed generator, even if the distributed generator is operating at the time switchover is required. Extremely fast switches are available but they are expensive.

In addition to providing the load with backup power, switching load between the utility and the distributed generator allows a load to reduce the peak demand it imposes on the utility, to avoid using power when spot power prices are likely to be high, or to sell contingency reserves to the power system. Still, isolated operation is less flexible than operating in parallel with the utility. The isolated load must be matched closely to the distributed generator to avoid wasting excess generating capacity or falling short of supplying the load.

GENERATOR TYPES

Utility interconnection requirements are typically not related to the basic energy source that powers any given distributed generation technology. Whether the energy comes from a fuel cell, a microturbine, a reciprocating engine, or a windmill is unimportant. How the energy is converted to 60-Hz power used commercially is somewhat more important. For that there are only four technologies: synchronous generators, induction generators, self-commutating invertors and line-commutated invertors (Exhibit 4). Generators typically convert mechanical energy into alternating current (AC) electric power. Fuel cells and photovoltaics produce direct current (DC). Invertors are solid-state electronic devices that convert DC electricity into AC of the desired frequency and voltage. A combination of a rectifier and an inverter is used to convert high frequency AC electric power produced by generators connected to microturbines (most of these rotate too fast to produce 60-Hz power directly) into DC then into 60-Hz electric power.

5. TRANSMISSION CONCERNS

Restructuring is also changing how transmission is operated and prices. Because flows on individual lines cannot be easily controlled in an AC network and because capital costs are high while operating costs (incremental costs) are extremely low, transmission will almost certainly remain regulated. Distributed generation might be considered less dependent on transmission than other forms of generation because distributed generation is generally located close to or co-located with the load it primarily serves. (Wind generation is an exception in that it is often located remotely from loads.) Transmission is important to distributed resources, however, because of the impact it has on local *prices*.

Transmission costs only about one tenth as much as generation so it is appealing to think that we should have enough transmission so that the system is rarely congested and commerce can flow freely over the system. Unfortunately this is not practical. Transmission is difficult to build. There is often public opposition to the construction of new lines. And since flows on individual lines can not be controlled activities in one part of the system affect flows throughout the system. Consequently constraints can appear in different locations at different times. Assuring that constraints seldom appear would likely require expensive overbuilding.

Since flows on individual lines can not be controlled directly, overloads (actual or potential) are relieved by redispatching generation. Generation is lowered at some locations and raised at others. Redispatch incurs a cost because the generation that is reduced was selling at a lower price than the generation that was raised. It is primarily the way this redispatch cost is recovered that impacts distributed generation.

Under traditional transmission pricing, the cost of building and operating the transmission system, including the redispatch cost to alleviate congestion, is spread among all customers based on their energy use, demand, or both. Under restructuring, FERC is advocating and several RTOs are implementing transmission pricing that addresses congestion through competitive markets. This is done by allowing local electricity prices to reflect the cost of alleviating transmission congestion. A number of schemes are possible, using either nodal or zonal prices; the important point for DR is that the volatility across both time and space of prices increases because of congestion.

Exhibit 4. Generator Types

Synchronous Generator: An electromagnet or a permanent magnet on the rotor produces the magnetic field in a synchronous generator. As a consequence the frequency of the AC electric power produced (60-Hz for example) is exactly related to the rotational speed of the generator (1800 RPM for example). Similarly, the magnitude of the voltage produced (and the reactive power delivered to the power system or consumed by the generator) is directly related to the strength of the magnetic field. A synchronous generator with an electromagnet can control its output voltage and real and reactive power outputs. Synchronous generators are excellent at supplying isolated or interconnected loads. Almost all traditional utility generators are synchronous machines. Synchronous generators have relatively high surge capacity (extra power available for a few seconds) which is useful for motor starting but also produces high fault currents which can damage utility equipment when short circuits occur.

Induction Generator: An induction generator relies on the power system to induce the required electric field in the generator's rotor. As a consequence, the electrical frequency is not locked to the rotational speed of the generator (a 60-Hz generator might spin at speeds between 1820 and 1860 RPM to deliver power to the grid, for example). An induction generator cannot control its output voltage and it consumes reactive power. Therefore, induction generators are not good at supplying isolated loads. Unfortunately this characteristic cannot be relied upon to guarantee that the generators will not support an isolated island. If there is just the right amount of capacitance and real load in the island, the induction generator can continue to energize an isolated island. Induction generators have lower surge capacity than synchronous generators so their ability to support motor starting is reduced. The output drops rapidly as voltage collapses, so they have relatively low fault contribution.

Self-Commutating Inverter: Inverters convert DC electricity to AC power by rapidly switching DC power of the appropriate polarity on and off. A self-commutating inverter does all of the required switching itself. As a consequence, a self-commutating inverter can control frequency and voltage, real and reactive power, and is suitable for powering isolated or interconnected loads. Inverters have relatively low surge capability and fault contribution, often not much more than the normal rated output.

Line-commutated Inverter: A line-commutated inverter relies on the power system alternating current passing through zero twice each cycle to perform half the switching operations. Thus, it cannot control voltage or frequency, consumes reactive power, and is not suitable to power isolated loads. Unfortunately, as with induction generators, this characteristic cannot be relied upon to guarantee that the inverter will not support an isolated island. If there is just the right amount of capacitance and real load in the island the

Congestion pricing can be good or bad for individual distributed resources but it will primarily be good. Loads would like to locate at low-price locations, on the generation side of congestion, but this may not always be possible. Distributed generators should try to locate at high price locations, on the load side of congestion. Loads that locate on the high-priced side of congestion for other business reasons will find the addition of distributed generation to be more attractive. Similarly, controllability of the load has more value on the high-priced side of congestion than on the low side.

Congestion relief also rewards response speed. Congestion is only somewhat predictable and usually only lasts for a few hour at a time. Resources that deploy quickly are better able to respond when prices change unexpectedly. Similarly, if regional rules are set appropriately, distributed generation or agile loads can allow congested transmission to be loaded more heavily. Generators and/or loads are poised to respond if there is a contingency rather than reserving transmission capacity for contingency response.

Regulated transmission and competitive generation conflict when it comes to investment. An investor in DR expects to take the normal commercial risk that another investor may choose to locate nearby and compete. The market will decide which of the two competitors is preferred. But transmission investment decisions are made in the regulatory arena. Transmission's costs are almost all capital, so once the decision is made to invest, the costs are sunk. The investor in DR technology that is counting on serving a high-price congested area runs the added risk that a regulator or RTO will decide to invest in transmission and alleviate the congestion. At that point, even if the distributed technology is the better economic choice, the distributed resource will lose because the transmission cost is sunk, marginal cost is zero, local prices drop, and the regulatory environment guarantees the transmission project's profits.

Intermittent remote resources such as wind are the most vulnerable to transmission pricing reform if they are located on the wrong side of transmission congestion. Being intermittent it is difficult to economically reserve transmission capacity as it may not be needed during any given hour. They also do not have the option of rescheduling production to times when the transmission system is unconstrained. Since transmission is still regulated it may be best to try to obtain regulatory relief based upon the societally desirable nature of their generation.

6. AGILE MARKET RESPONSE, A VISION OF HOW THE SYSTEM CAN WORK

Distributed resources are likely to interact differently with the power system in the future. A distributed generator wishing to interconnect with the power system today faces an installed distribution system with set protection schemes, safety procedures, reliability rules, tariffs, and market structure. The utility may not recognize that adding distributed generation to the existing resource mix benefits the power system. Penetration of grid connected on-site generation remains low, so this is likely the only distributed generator on the feeder or substation. Consequently, utilities expect the distributed generator to accommodate the genuine physical and commercial constraints of the power system. Utilities do not expect that the power system to incur large costs, at the expense of the majority of users, for the benefit of a few users.

For example, islanding a portion of the distribution system is currently considered a serious safety risk. The utility requires the owner of the distributed generator to ensure that the generator cannot energize a distribution line that is intended to be dead. If the utility supply to the line is interrupted, the distributed generator must detect the departure of the utility and de-energize the line too. In many cases there may be no economic alternative to this mode of operation for existing distribution lines, as reconfiguring an existing feeder's protection scheme could be very expensive. The implementation and expense will be debated, but the basic philosophy of de-energizing under adverse conditions may be economically unavoidable.

From the perspective of the overall system, however, this is not a desirable design philosophy because it defeats a primary benefit of distributed generation, increased reliability. It would be much better if the distribution feeder protection scheme was designed to exploit the distributed generators' ability to support an islanded system. The distributed generators could sell backup supply to other customers on the feeder, benefitting all parties including the host utility.

Although it may be necessary to accept reduced benefits from distributed resources for the present, designers of distribution expansion should ensure that the full capabilities of distributed generation are supported in the future. Utilities will come under pressure for this solution from at least three directions. First, as users and distributed generation manufacturers get more comfortable with basic energy production they will want to expand their range of operations. Second, state regulators will continue to pressure utilities to accept greater amounts of distributed generation. Finally, and perhaps most importantly, system operators will recognize that distributed generation can sell reliability services to the system. System operators tend to be conservative and slow to adopt new technology, but they also like having a large pool of diverse resources to draw upon when the power system is under stress. They may provide the strongest impetus for change, with the power system actively recruiting distributed generation rather than fighting it. This may occur more quickly as FERC encourages RTOs since the system operator will organizationally be at greater distance from the traditional large generators.

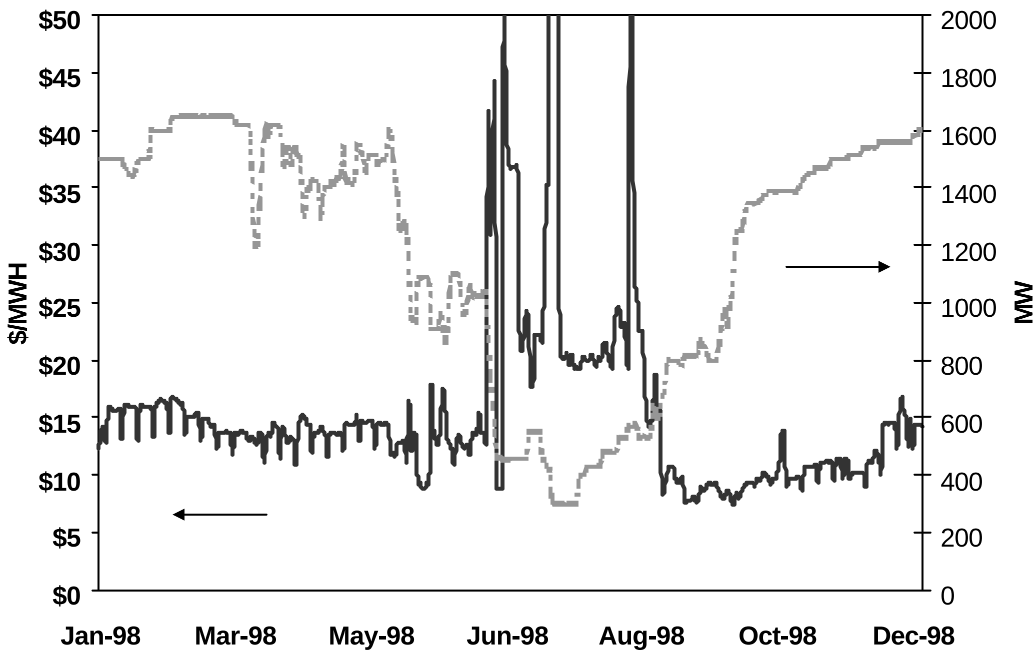

Figure 4 Resources that can respond to fluctuating prices should be allowed to participate in bulk power markets for energy and reliability as this large load does.

The power system of the future may fully integrate DR into energy and ancillary service markets. Prices for energy and the ancillary services would change hourly (or faster) to reflect current system conditions. As the system became stressed prices would rise. Broadcasting prices would allow all resources—loads and generation—to respond and mitigate reliability concerns. Price would be the dominant means of achieving desired response, not command-and-control signals. Loads and generators that could not respond, due to their own economic or physical constraints, would be free to continue operating as their internal requirements dictated. Commercial financial instruments would replace regulatory rate design to shield those unable to respond from the volatility of markets. Those that could respond would receive the economic benefit. Aggregators and marketers would help both the system operator and individual generators and loads by bringing together resources with complementary capabilities. Automated decision tools would likely handle interactions with energy and ancillary service markets while still leaving DR owners in control of their own facilities. By watching the market for some time each participant could decide if investing in additional flexibility would be profitable for them. Flexibility could be gained by adding distributed generation, controlling their load, or adding forms of storage. This process allows markets to optimize the power system and the individual participants businesses while minimizing central planning and control. As shown in Figure 4, some loads are currently able to tap bulk power markets and significantly reduce their power costs by maintaining sufficient flexibility that they can maneuver as fast as the bulk markets require. Hopefully this opportunity will be extended to all loads and distributed generators in the future.

7. CONCLUSIONS

The future for DR is uncertain. The technologies for distributed generation, storage, and load-control are advancing at a rapid pace. Communications and control technologies are making similar progress. Distributed resources are, or will soon be, at a point where they can make a major impact on the physical operation of the power system in terms of reliability and economics. Price-responsive load is probably the largest untapped resource available. The extent to which these resources are allowed to participate in energy and reliability markets is an open policy question.

Distributed resource's ability to help system reliability depends upon a number of factors.

- Will interconnection standards prohibit distributed generators from being able to supply reliability services (ancillary services) by forcing them to trip off line whenever voltage or frequency deviates?
- Will ancillary service standards adopted by NERC and the regional councils be defined in terms of the historic large generator technology or will those definitions be technology neutral, allowing distributed generation and load to participate in ancillary service markets?
- Will tariffs be changed such that DRs see real-time prices for energy and ancillary services and thereby be provided with incentives to respond to system needs?
- Will communications, control, and metering technologies support the rapid response required for DR to supply ancillary services?
- Finally, will the DR technologies themselves provide sufficient controlled response to be of use in supplying reliability services to the bulk power system?

It seems likely that the political and regulatory process will resolve these issues in favor of DR. The match between the inherent capabilities of DR and system reliability needs, as expressed in the ancillary services markets, are good. The real-energy load/generation balancing services of regulation, load following, frequency responsive spinning reserve, supplemental operating reserve, and backup supply value fast controllable resources. Higher prices are paid to faster responding resources that can provide the higher quality services. Participation in these markets depends on the resource being able to receive and respond to the market prices for each service. A massive infusion of fossil-fuel distributed generation into the market can help renewable based distributed generation by eliminating some of the barriers to full participation. The service each resource can sell will be determined by the physical capabilities of the individual installation.

Three other factors are compelling the current push to develop distributed generation. First, the efficiencies of smaller generators are increasing, with combined-cycle combustion turbines nearing 60% efficiency. These machines are large by distributed generation standards but small when compared with 1000-MW thermal plants. Microturbines are commercially available and efficiencies are expected to rise. Internal combustion engine efficiencies are also rising, nearing 40% for advanced engines. Second, the relative abundance and low price of natural gas makes this the fuel of choice for distributed generation, greatly reducing pollution concerns. Third, the low capital cost and short lead times of distributed generation is a much better match to today's competitive markets than traditional large generators that can take 10 or more years to complete.

A critical distinction from past use of controllable load is that the DR *owner* must be in control of the resource, free to enter and leave each market based on the owner's needs. The resource must be bound to commitments to provide services that it has agreed to provide but these agreements should be in alignment with hourly markets, not multi-year obligations.

Aggregation is both necessary (the system operator cannot directly deal with thousands of responding entities) and a benefit (the statistical response of thousands of small independent entities is much more predictable than the response of a single large entity). The communications requirements, in terms of the required speed and the number of entities that must be communicated with, are daunting but advances in communications technology appear to be up to the task. Market provision of ancillary services, as opposed to the vertically integrated utility's command-and-control system, requires that prices be negotiated through a bidding scheme before each market closes. Faster communications will be required when deployment of reserves is required, but this type of signal can be broadcast to all the responding resources, it need not be specific to each entity. Certification and after-the-fact metering can replace real-time monitoring of each distributed generator or responding load. Aggregators will provide a valuable service by assembling DR collections to present large blocks of controllable power to system operators.

Hopefully, markets will develop to provide the opportunity, flexibility and price signals required to fully integrate agile loads, distributed generation, and local storage fully into the power system. This should raise system reliability while optimizing the economic performance of both the participating customer and the power system.