Restructured Electricity Markets Offer Increased Complexities… and Opportunities… For COGENERATION

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ABSTRACT

Electric industry restructuring has complicated the decisions associated with investing in and operating cogeneration facilities. On the other hand, it is starting to provide the opportunity to genuinely add value by allowing market signals to help optimize both the power system and the cogeneration facility. It is important to look beyond existing tariffs to the underlying physical requirements. If the cogeneration facility can be designed and operated in a way that benefits both itself and the power system, tariffs can likely be changed to compensate it for its actions.

Electricity is a unique product in that production and consumption must be matched essentially instantaneously. Storage is not practical.* Use of alternating current, while it provides the tremendous benefit of relatively cheap voltage transformation, further restricts operational options. Flow can not be easily controlled on individual transmission

*Pumped storage plants do exist but their numbers are limited. They store energy as mechanical potential, not as electricity. In the context of this paper, they behave more like conventional generators rather than true storage devices. They arbitrage over hours, not seconds.

lines so control of the system to prevent overloads must be accomplished by redispatching generation.*

Consequently the production cost of electric power is highly volatile. In spite of this, historically we have elected to isolate the consumer from the power system's real-time production cost. Consumers use power whenever they choose and the power system responds to accommodate those needs. The customer does not see prices that reflect current conditions and cannot benefit financially if it takes action to help the power system.¶

Restructuring of the electric power industry is changing all of this, and cogeneration can benefit by exploiting the opportunities presented. Retail tariffs are slow to change. It is better to examine the physical requirements of the power system and the wholesale markets to determine how cogeneration can prosper in a restructured environment than to focus only on current tariffs. It may be necessary for cogeneration proponents, along with distributed generation and agile load proponents, to press for tariff changes with their state regulators.

Cogeneration can prosper by recognizing that the prices of electric energy and the reliability services (ancillary services) vary dramatically in time. These price changes are only somewhat predictable. Prices will generally be higher on hot August afternoons than they are after midnight on spring mornings. But times of extremely high prices, like the $7000/MWh and $9000/MWh prices seen in the Midwest over the past two summers, are less predictable. Owners of cogeneration facilities can benefit by curtailing consumption, by selling energy to the power system, or by selling reserves to the power system during times of high price.

It is critical to evaluate the *integrated* cost to the cogeneration facility of responding to power system markets. These costs will vary from time-to-time depending not only on the prices the power system presents but also upon the activities going on at the cogeneration facility and the price of fuel. The cogeneration facility must retain control over its own operations, responding to changing prices as appropriate *at that time.*

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*Phase angle regulators and Flexible AC Transmission devices can control flow on individual lines but they are very expensive and used only rarely.

¶Demand charges and time-of-use rates provide only limited incentive for consumers to reduce the burden they place on the power system when costs are *expected* to be high.

WHICH RELIABILITY SERVICES MIGHT CO-GENERATION FACILITIES SELL?

Table 1 presents the 12 ancillary services (reliability services) commonly discussed.[1] These services are required to maintain bulk power system reliability and are being opened to competitive markets. Clearly cogeneration facilities will not sell System Control, System Black Start, or Dynamic Scheduling. Energy Imbalance and Real-Power-Losses are primarily accounting services with the required physical energy and capacity coming from other services. Cogeneration Facilities 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 cogeneration facilities should excel at if they are connected to the power system through an inverter.

The five remaining services (Regulation, Load Following, Frequency Responsive Spinning Reserve, Supplemental Reserve, and Backup Supply Plan) deal with maintaining or restoring the real-energy balance between generators and loads. These services are characterized by the required response time, the response duration, and the communications and control required to facilitate the service.

Figure 1 shows the required response for the five energy balancing functions. Because regulation requires continuous adjustment of real power transfers between the resource and the system, cogeneration facilities may not want to provide this service to the power system. The contingency reserves are especially amenable to being provided by co-generation. Load following could be provided directly or through the use of a spot market price response on a shorter time frame than 1 hour.

Similar restrictions apply to cogeneration facilities 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 cogeneration facility selling contingency reserves must have capacity it can unload when the contingency occurs, either by increasing its electricity output or by temporarily curtailing load.

Providing ancillary services from cogeneration facilities should involve a careful integration of generation and load response. Since fast services generally command higher prices than slower services it is

Table 1. Key Ancillary Services and Their Definitions

System Control: Control-area operator reliability and commercial functions

Reactive Supply & 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 CPS 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 Plan: Customer plan to restore system contingency reserves within 30 minutes if the customer's primary supply is disabled

Real-Power-Loss Replacement: Compensation for transmission system losses

Energy Imbalance: Accounting for the hourly discrepancy between scheduled and actual transactions

Dynamic Scheduling: Real-time metering telemetering, and computer software and hardware to electronically transfer some or all of a generator's output or a customer's load from one control area to another

Network Stability: Use of fast-response equipment to maintain a secure transmission system

System Black Start: The capability to start generation and restore all or a major portion of the power system to service without support from the outside after a total collapse

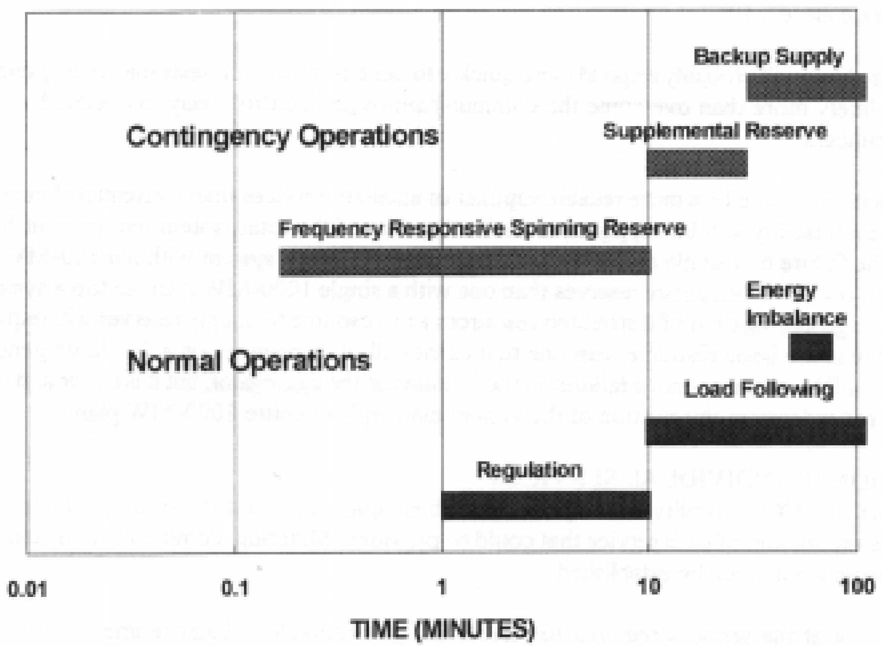

Figure 1. Required Response Times

desirable to sell the fastest service possible. At times it may be faster to temporarily curtail load and restore the load to service as additional generation is brought on line if the generation is not already operating.

WHY UTILIZE COGENERATION AS A POWER SYSTEM RELIABILITY RESOURCE?

For the cogeneration facility the reason is money, either through reduced power bills or through an added source of income. From the power system's point of view there are several reasons that cogeneration facilities (and all distributed generators and loads) should be encouraged to sell ancillary services. FERC is encouraging open competitive markets for generation. FERC ordered the unbundling of ancillary services 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 participation by 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 do what it was designed for, i.e., 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.

Cogeneration facilities should 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. 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 distributed resources as a resource to supply reserves will require less redundancy in the basic resource than one that carries all of its reserves on a few large generators. There can still be common-mode failures in the facilities of the aggregator, 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 cogeneration facility, 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.[a] Response must be maintained for an additional 20 min-

[a]Specific timing requirements for each service vary from region to region. The requirements referenced here are from NERC (1998) Draft Policy 10.

utes, i.e., until 30 minutes after the contingency. This is a short interruption that many customers may find acceptable. Integration with the cogenerator's 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. Candidates include water pumping, building temperature control, water heaters, and air compressors.

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 cogeneration system and its load to respond.

Frequency Responsive Spinning Reserve is both easier and more difficult for distributed resources 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 harder for some generation that is not on-line to provide. Again, an initial response by the load, followed by a response from the cogeneration system might be ideal. Having each facility in an aggregation responding at slightly different frequencies could create a typical generator droop characteristic.

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 was receiving the lost generation 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. Some cogeneration facilities 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.

Cogeneration facilities 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.[2]

Regulation is the least likely of the generation/load balancing services for cogeneration facilities to provide. 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.

PAST USE OF LOAD CONTROL

At first this all sounds like traditional utility load control applied to cogeneration facilities, but there are major differences. Load control has been and is currently used in a number of locations.[3] Some implementations have been successful but the idea has not been universally adopted.

This is at least partly because of traditional rate structures, which provide little flexibility to customers. The customer must agree up front to be subject to utility control, usually for a year or more. There is no ability to enter and leave the market as the customer's economic conditions change. The customer often gets paid a flat fee independent of how or if the resource is actually used. This provides little flexibility for the load and little incentive to actually perform.

Similarly, in the energy market, the costs of peaking generation or peak reserves are typically spread over an entire season or year. Charges (both operating and capital) are not assigned exclusively to the hours when the generation or reserves are required. Assigning the costs to the hours when they are needed would result in much higher prices for those services during specific hours (and lower prices at other times). Under either good economic regulation or a truly competitive market, the result would be the same total revenue collection (that required to pay for the resource). Providing a price signal that accurately reflects the real-time cost to provide the service will encourage all suppliers, loads and generators, to offer supply when it is needed most.

SUPPLIER CONTROL OF ITS FACILITY

While automatic deployment is necessary when selling some reserves, it is often important to allow the customer to decide when it will participate and when it will not. 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 without high costs being incurred. These times are often independent of anything happening on the power system and are therefore unrelated to the price of the service.

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 on the evening 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. In fact, 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 utility needs information about which facilities will be supplying services ahead of time. The cogeneration 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 cogeneration facility will need the ability to change the availability on shorter notice, perhaps with economic consequences.

A cogeneration facility that experiences 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 are intended to 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 (as is 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.

CERTIFICATION Vs METERING

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 2 to 8 seconds. The amount of data and the expense per MW are both reasonable. When the operator calls for response the response can be monitored in real time.

Providing the same information from hundreds or thousands of individual resources would be prohibitively expensive and would provide an overwhelming amount of data that could not be managed in real time. An alternative to real-time monitoring of each individual resource exists. Cogeneration facilities could be certified, either individually or in aggregation, for the provision of each ancillary service. Certification would consist of exercising the resource under controlled conditions to determine the reliable response.[4] 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. Recording meters at each resource could also be audited to verify performance for both actual events and tests.

AGGREGATION AND COMMUNICATION

The major objection often voiced to customer 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 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.

Communications are inherently different with an aggregation of resources than with a single entity. As mentioned above, it is not currently practical to collect data from thousands of individual facilities every 2 to 8 seconds. It is practical, however, to send instructions to those facilities as fast as necessary, That is because it is the same signal going to large groups of the facilities. That signal could be "deploy now" or it could be "the current price for response is $X."

CUSTOMER ECONOMICS

In competitive bulk-power markets, customers will have many choices with respect to their use of electricity and their payment for electricity services. In the context of this discussion, they can choose to participate in hourly markets and face spot prices that can vary widely in response to supply/demand relationships. Alternatively, they can sell reserve services (options) as discussed above. Decisions on whether to participate in spot markets or sell reserves will be based on the customer's flexibility in modifying its electricity generation and use (in particular, its fixed and variable costs to modify its electricity generation and use in real time), the prices of energy and reserve services, and the frequency with which outages occur.

For example, higher reserve prices and less frequent outages will lead customers to sell reserve services, forgoing opportunities to reduce consumption or increase generation at times of high spot electricity prices. On the other hand, increasing flexibility (i.e., declining cost) in modifying electricity use or self generation will lead to more decisions to participate in spot energy markets.

CONCLUSIONS

Real-time electricity prices are volatile, they reflect the changing costs associated with balancing supply and demand in an environment where there is essentially no ability to store the traded commodity. Costs associated with the cogeneration facility change dynamically as well. Electricity prices are important but they are only one of several cost factors the cogeneration facility must juggle as it strives to maximize its own profit.

In many cases it may be advantageous to sell reliability services to the power system. Avoiding peak prices may require reducing demand for 4 to 8 hours or longer, Selling contingency reserves may only require standing ready to reduce load (or generate power) for 10 to 30 minutes in the event of a power system contingency.

There are design, contracting, and operations decisions that must be considered: Design and build systems that maximize flexibility, negotiate contracts that provide flexibility, make operational decisions based upon the real time prices of electricity, ancillary services, alternative fuels and the impact on current operations. Seasonal diversity between gas and electricity prices generally helps with the highest electricity prices (or curtailments) coming in the summer and the highest gas prices (or curtailments) coming in the winter.

Things are not so fortunate for use of the waste heat coming from the generator supplying local heating. Supplying cooling may be a better match. This is another reason to look at selling contingency reserves. It is also often easier to introduce storage on the load side. Thermal storage is easier to build than electric energy storage. Even short term storage (10 minutes) can have real value.

References

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Brendan's interests include electric industry restructuring, ancillary services, distributed resources, demand side response, energy storage, renewable resources, and advanced analysis techniques. He has published over 50 papers, articles, and reports. He is participating in the IEEE SCC 21 Distributed Generation Interconnection Standard working group, served as staff to the Department of Energy's Task Force on Electric System Reliability, was a member of the NERC IOS Working Group, and has appeared as an expert witness in FERC and state litigation. He has conducted research projects concerning restructuring for the NRC, DOE, EEI, numerous utilities, state regulators, and EPRI.

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