Completing the Market Design

Howard F. Illian, President, Energy Mark, Inc., Buffalo Grove, Illinois 60089

***Abstract* — As the electric industry moves toward completing restructuring into competitive markets, many believe that all of the major structures necessary to achieve success are understood. But a careful review of the status indicates that the market design, as characterized by the FERC SMD and other working markets, is still incomplete. This paper will provide support of this position with specific examples of why the market design is incomplete, list some of the issues that must still be resolved, and indicate research initiatives that, if completed, will allow a working market design to be completed.**

***Index Terms* — Ancillary Services, Market Design, Power System Reliability, Power System Security.**

I. INTRODUCTION

CURRENT market designs as applied world-wide are not complete. They do not assure a long-term stable market.

This statement is made from a perspective that differs from most observers of our industry.

A. Frame of Reference

As a former system operator, I approach the problem of restructuring differently. The first and foremost issue is that electricity markets must support reliability. This stems from the inability of electric systems to ration the product. It is a consequence of a lack of economic storage to inventory product. Electricity must be produced in the same instant that it is consumed. When supply and demand for the product fall out of balance, the system fails, no one receives service, and there is no market. The financial losses to the customers resulting from failure can be significantly greater than any savings resulting from the efficiencies of competitive electricity markets. Thus, restructuring is risky unless it can be done in a manner that fully supports reliability.

However, as an economist who has spent an entire career in an industry that has significant built-in inefficiencies resulting from cost based regulation, I applaud the efforts to restructure. If the industry can be restructured into reliable and competitive markets, the payoff will be well worth the effort. Unfortunately, failure results in the Humpty-Dumpty effect. Can the industry be returned to a structure that can be effectively regulated? It is a one way street. The journey has begun. It must be completed successfully.

B. What is Reliability ?

The North American Electric Reliability Council defines reliability as a combination of adequacy and security. An electrical system is secure when it can be upset and still remain in service. Security requires reserves to insure that sudden imbalances can be limited before system failure. Adequacy is required because without adequate capacity, the reserves necessary to return the system to a secure state will not be available when needed after an upset. It has been recognized by many that supply adequacy has not been sufficiently addressed by current market designs. This is the reason that many regions are considering additional ICAP Markets to attempt to insure adequate capacity.[1] Addressing adequacy alone fails to recognize the function of the system operator in preparing the system for upset and recovering from an upset when it occurs. The system operator facilitates the transition from adequacy to security. It is this transition process that requires many of the Ancillary Services[2] that have been included in the markets. It is this process of transforming adequacy to security that has been left out of current market designs. As long as markets are designed without internalizing this process they will be unable to support reliability.

II. IS PRICE VOLATILITY ENOUGH ?

Current solutions to the market design problem use price volatility to assure adequacy. The assumption is that if the prices are high enough, new capacity will be brought to the market and will be available for dispatch when required. This assumption has many problems.

A. Assuring Adequacy:

Price volatility will assure adequate capacity, but at the cost of additional uncertainty. When price volatility is the only market signal to provide the incentive to install new capacity, there is an additional supply uncertainty included in the problem that has not been previously included. This uncertainty is reflected by an uncertainty distribution that results from the differences between suppliers risk aversion. It results in significant additional uncertainty in the relationship between a specific price and the response to that price by suppliers. This uncertainty has never been part of this process. What effect does including this uncertainty have on reliability?

Also, the political environment in North America currently makes unlimited volatility an unacceptable alternative and as a consequence most markets have some form of price cap in place that has the effect of limiting volatility. This form of price control raises the question of whether price volatility can provide the incentives required to assure adequacy in the

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Howard F. Illian is President of Energy Mark, Inc., Buffalo Grove, IL 60089 USA (847-913-5491; fax: 847-913-5498; e-mail: howard.illian@energymark.com).

[1] Some feel that markets with high price caps can insure adequate capacity through price volatility and scarcity pricing. This solution may result in other problems with respect to who is disadvantaged by volatility and scarcity pricing. It may also result in unintended reliability consequences.

[2] Ancillary Services in the context of this paper only include the real-energy services and exclude Reactive Power and Black-Start.

market. Recognition of these limitations on price volatility is also fueling efforts to create ICAP markets to address the resulting revenue adequacy problems.

B. Assuring Security:

Since reliability requires both adequacy and security, questions must be asked about the ability of price volatility to assure security. An additional uncertainty similar to that raised above is added to the problem in this step. Since the system operator incurs costs when transitioning from adequacy to security, and the energy providers incur costs standing ready to supply response, how are these opportunity costs associated with the transition from adequacy to security included?

Can one assume that by using volatile pricing strategies, the opportunity costs can be captured in the energy price? This requires that the opportunity costs associated with this transition from adequacy to security be passed to the customer in the form of higher energy prices. The traditional solution has been to put these costs into uplift. Does uplift correctly assign these costs to market participants?

C. Do Ancillary Services Reduce Price Volatility ?

It is clear that when ancillary services are used they reduce market price volatility. This is obvious because part of the cost has been placed in the option or reservation price. How does this affect the validity of prices revealed by a market based on volatility? Are prices derived from such a market the correct prices? Are the correct prices masked by the use of the ancillary services reserved? Can this problem be eliminated by insuring that the dispatch intervals do not overlap?

D. Does Price Volatility Reduce Ancillary Services Needs ?

If the logic of allowing the price volatility in the market to inject the incentive to provide the appropriate amount of ancillary services is correct, then by allowing high price volatility and shorter market intervals, ancillary services could be eliminated entirely. Does a market based on price volatility require ancillary services? If ancillary services are partially paid for in advance, how should the price associated with the reservation of the energy be included in the market? If ancillary services are included in a market based on price volatility, is there a risk of paying for a portion of those ancillary services twice?

E. Price Volatility and Reservation Costs:

The current methods of acquiring ancillary services arrange for these services in advance of their use in the market. It is well know that one way to affect price volatility is to arrange for capacity to deliver energy when needed in advance. In addition, many markets enable the system operator to commit units in anticipation of shortages of committed capacity to provide the necessary energy. These commitments affect the price volatility of the market. This suggests that the prices set in a market dependent upon price volatility can be influenced by system operator decisions. How do these operator decisions affect prices?

F. Overlapping Intervals:

As the system approaches real-time it becomes very difficult, if not impossible for the system operator to know the root cause of an imbalance on the system. As a consequence, it is not possible for the operator to know what resources, reliability or market, to dispatch to return the system to a balanced condition. This creates a two-fold problem in the pricing mechanism. The first problem is the affect that dispatching from the wrong resources will have on market prices. If the market has separated the resources, the result of dispatching from the wrong resource is the calculation of an incorrect price. The second problem occurs when it is appropriate to dispatch from both resources concurrently. Under these circumstances, the market clearing price is significantly affected by the dispatch of the reserved services. How does the concurrent dispatch of market energy and ancillary services influence market price? Can the dispatch of ancillary services overlap with the dispatch of market energy within a common interval? Does a unique price result from this dispatch situation?

G. Discussion:

Ancillary services are required for every market independent of the price volatility or market interval. The interconnection fails without them because the Frequency Response ancillary service must be delivered within any reasonable market interval before the price volatility can elicit a price response. If price volatility alone is used to provide the incentive for market participants to stand ready-to-supply balancing energy from Frequency Response, the market fails due to a lack of Frequency Response because that service must be provided to balance the interconnection before the market price responds. Frequency Response cannot be rewarded through ex-post energy pricing because it offsets the ex-post pricing mechanism. Frequency Response cannot be rewarded through ex-ante energy pricing because the events causing the frequency error that require this service cannot be forecast. This raises basic questions about the basic understanding of ancillary services in a market.

III. NON-OVERLAPPING INTERVALS:

The concurrent use of energy products that are used to set market prices and ancillary services that have been reserved result in indeterminate energy prices. The system operator does not always know what the problems causing the need for action are in real-time. Therefore, the system operator cannot parse these decisions between reliability based energy products, reserves, and market based energy products, balancing energy, when operating the system.

This leads to a solution that is different than the methods used in the designs of current markets. This solution is to separate the market operation from the system operator reliability operation by eliminating the overlap of intervals in which these functions are concurrently performed. The market would be responsible for finding the closest solution to optimal on a forecast basis. Then, at some interval before real-time, the market ends, fixes its prices, and hands the problem over to the system operator to implement that solution reliably.

For example, the market could be solved one hour before real-time and then that solution could be handed over to the system operator to manage the risks associated with starting with the market solution and ending with a reliable real-time delivery solution. The differences in costs could be collected and allocated to those responsible for the differences between the market solution and the real-time operation. Under this type of design, the operator is allowed to operate the system without interference from the market and the market will attempt to develop forecast solutions that are as close to the real-time solution as is economically justified.

The system operator would still anticipate reliability needs, reserves, and acquire ancillary services ahead of time to meet those needs in real-time. The lumpy, non-convex, nature of these costs would be collected and allocated to the differences between the market solution and the real-time operation.

IV. Transitioning From Adequacy To Security

The highest value-added contribution to electricity is made by the system operator. The value-added contribution results from decisions the system operator makes to convert adequate capacity to adequate response and real-time security. This component of operations has not been captured and integrated into any market design anywhere in the world. An example clarifies the nature of this process.[1]

A. *Example of Converting Adequacy to Security*

An example of an adequacy to security transition should provide additional insight into this process.

B. *Assumptions:*

- Three 500 MW generating units serve load on a system.
- Each generating unit has a 5% droop characteristic.
- They are serving a total load of 1275 MW.
- Response desired is 150 MW for 0.3 Hz frequency change.
- Unit 1 - incremental cost = $30 / MWh, output = 450 MW.
- Unit 2 - incremental cost = $40 / MWh, output = 450 MW.
- Unit 3 - incremental cost = $50 / MWh, output = 375 MW.
- The total hourly cost is $ 50,250.

C. *Problem:*

The system load unexpectedly increases by 75 MW. What does current operating practice tell us about how to load these units while maintaining a reserve of 150 MW?

D. *Alternative 1: Load the units economically.*

- Unit 1 is loaded to 500 MW.
- Unit 2 is loaded to 475 MW.
- Unit 3 is loaded to 375 MW.
- The total hourly cost is $ 51,400.
- The frequency response remaining is 75 MW.

E. *Alternative 2: Load to maintain response.*

- Unit 1 is loaded to 450 MW.
- Unit 2 is loaded to 450 MW.
- Unit 3 is loaded to 450 MW.
- The total hourly cost is $ 54,000.
- The frequency response remaining is 150 MW.

F. *Result*

The cost of the 75 MW of additional frequency response provided by Alternative 2 is $ 35 / MW.

G. *Discussion*

This example is just one demonstration of the added value that the system operators contribute to the system. When the system operators make decisions to substitute energy from one generating unit to another, they are transforming capacity to response. It can be concluded that what has been incorrectly defined as a capacity market in almost every electric market should be defined as a response market. It is also clear that except for unit commitment decisions, most of these decisions are made very close to real-time. If these markets are truly response markets, then the concept of capacity pricing is incorrect and the market designs that are based on capacity simply will not work correctly. It also indicates that the correct name for these services may not be Ancillary Services, but instead they should be called Reliability Services.

V. The Resource Pyramid

The example supports a definition of response rather than capacity as the basis for differentiating between Ancillary Services. If these services are defined as response based, the relationship between all of the market products can be explained by the resource pyramid shown in Figure 1.[2] This new definition changes the way markets should be designed. It also includes the highest value service, Frequency Response.

There are currently two initiatives moving forward within the industry to change this situation. The first is a request

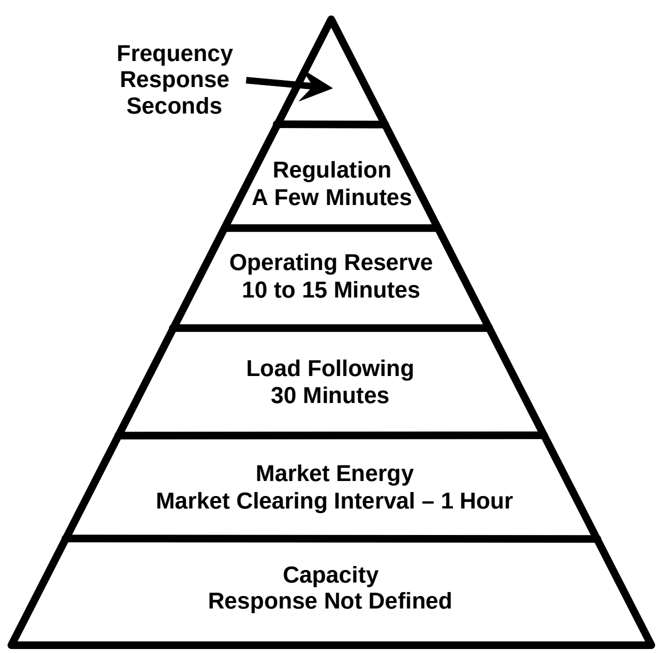

Fig. 1. The Resource Pyramid – describes the relationship of the services used to maintain the resource–demand balance required for reliability, and the response time for the service.

within the NERC community sponsored jointly by the Resources Subcommittee and the Interconnected Operations Services Task Force to develop a new operating standard to insure adequate frequency response. The second is an IEEE technical task force white paper on the importance of maintaining adequate frequency response on the interconnections throughout the world. Both are concerned with the lack of price signals within current market designs to insure adequate frequency response.

There is only one market in the world today that includes frequency response as an ancillary service, and the reason for doing so is not to insure adequacy of response, but to differentiate one type of frequency response from another.[3]

VI. What Are Ancillary Services ?

A few questions might help to clarify ancillary services and clarify how they should be integrated into the market.

A. Are ancillary services used by the customer?

Ancillary services are not used by the customer. They are used by the system operator to manage risk for the customers. The risk that they are used to manage is the risk of imbalance between the resources and demand in the market place. Since the risk of imbalance is the result of both customer errors (load forecast) and generator errors (uninstructed deviations), both generators and customers are receiving a service from the system operator. The customer could choose to manage this risk individually by matching their demand to the output of the resources they have purchased. This is one way to self supply these services but it is not the most efficient or economic.

B. Are ancillary services energy or options on energy ?

The energy only definitions in use by most markets assume that ancillary services are energy equivalents. The form of the contracts and the way they are used by the system operator indicate that they are really options on energy. If they are options how should they be configured? If I purchase a call option on a stock, I won't pay the market price when I exercise that option. Should a call option on energy result in the payment of market price when it is exercised? The specific form of the option is differentiated by the how quickly the option may be exercised. It is the system operator's job to acquire the correct options and to construct a portfolio of these options that will assure the customers secure energy.

C. What does the customer receive?

The customer does not receive ancillary services directly. The customer does not receive energy directly. The customer receives reliability in the form of secure operations in real-time. Therefore, the customer is receiving a risk-based product, not an energy based product. This difference is subtle but critical. If this is the case, where did this product of Delivery Error Management come from?[3][4]

[3] The Nordic Market includes frequency response as an ancillary service, but for reasons due to the response characteristics associated with hydro units using long penstocks.

VII. What Does The System Operator Provide ?

One function of the system operator in modern power system operations is correctly described in the NERC Functional Model as the Balancing function. It is this function that uses the real-energy ancillary services that are being addressed in this paper. This function has both planning and operating components. When an operator commits a generating unit to the system, they are anticipating the need for adequacy capacity that can be transformed into adequate response before that response is required for use in real-time to balancing energy.

When the system operators make decisions about how to load the available capacity, they are performing the function of converting adequacy to security. An important part of the end state is the balance between economics and security in the form of the available responses maintained. This transition from adequacy to security and the subsequent dispatch of the resulting resources suggests that the real product the system operator is contributing is not energy but risk management associated with unscheduled energy.

As the system operator dispatches resources to balance energy he also constantly reconfigures the system to retain sufficient response to insure future security. These trade-offs between economic dispatch and retaining response to maintain security result in the risk management product of Delivery Error Management not an energy product as currently described in many markets. This is a primary inconsistency observed in current market designs.

VIII. Delivery Error Management

Delivery Error Management is the risk product that the system operator provides to both generators and customers when the system operator dispatches scheduled energy and ancillary services. It includes the management of both load forecast errors and uninstructed deviations. This relationship is shown in Figure 2. If one assumes that this product is risk based rather than energy based, the determination of how the product should be priced changes significantly.

It has been recognized by system operators for decades that

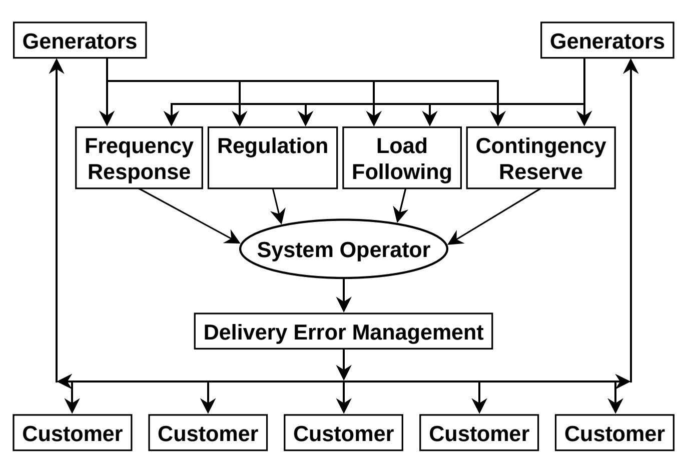

Fig. 2. Delivery Error Management – describes the relationship between the ancillary services acquired by the system operator and the service that the system operator provides to both generators and customers.

the most efficient way to dispatch an electrical system with multiple resources is to use an equal lambda dispatch. This is simply the operator's way of expressing that the correct price is a marginal energy price and that it should be applied to incremental use of all resources in an electricity market.

If the product is risk management instead of energy then there should also be an equal lambda solution in the risk domain that would indicate the correct marginal price for incremental risk, not for incremental energy. The answer that we are searching for to determine how to allocate this risk management product, Delivery Error Management, should have the form of an equal lambda solution. Equal increments of risk contributions should pay equal marginal prices for management of that risk.

IX. Solving The Unconstrained Market

Transmission constraints add the fog of major additional complexity to the problem of understanding how to integrate the above information into the electricity market. If constraints affect ancillary services and market prices, then the simplest form of reliability problem will appear in the unconstrained market. The design of the unconstrained market should be investigate to insure that equilibrium can be achieved while maintaining reliability, both adequacy and security, in the market using market price signals that include reliability risk management. Therefore, the electric industry and the academic community should be dedicating significant additional resources in the research on integrating reliability pricing into designs for electric markets that are unconstrained by transmission. This problem must be solved first. It will be impossible to determine how to integrate reliability pricing into a constrained market, if we do not learn how to integrate it into an unconstrained market first.

X. Size Matters

An important piece of information is that the necessary quantities of ancillary services proportionally increase as the size of the interconnection decreases. This provides a strong indication that when an interconnection is divided into a number of constrained areas, the total amount of ancillary services required to provide equivalent reliability might increase under certain conditions. If this is true, then transmission constraints could result in synergistic effects beyond those currently included in the market using today's methods. Current methods of determining ancillary service needs do not address this characteristic associated with the problem. We must understand this problem in greater depth.

XI. How Do Constraints Affect A/S ?

Early studies have shown that Ancillary Services also increase local costs when transmission is constrained.[5] If this is true, do current methods of pricing energy in transmission constrained areas reveal the correct prices? Is the reliability within the constrained region equivalent to the reliability of the remainder of the interconnection? When does the transition from constraints not affecting reliability to constraints that affect reliability take place? Is there some additional reliability cost that should be included in the local price of the constrained region? Is it fair for those paying the highest prices to receive the lowest reliability? The answers to these questions are dependent upon the results realized from the study of unconstrained markets in addition to the study of transmission constrained markets. Therefore, answers for unconstrained markets must be found before addressing constrained markets.

XII. Managing The Risks of Unscheduled Energy

Many questions have been raised about what we do not know and few answers have been provided. Most of the remainder of this paper attempts to set the stage for determining a plan of action to allow us to move forward by reviewing some of the answers developed. The incomplete part of the electricity market is the need to address adequacy, and therefore, reliability. This can be accomplished in a straight forward manner by pricing unscheduled energy. Unscheduled energy is the reason we need adequate supply and ancillary services, and is the reason that we are concerned with reliability. If a general solution can be found to manage unscheduled energy in a market, that solution will lead to the integration of reliability into market pricing. If the solution is general enough to be fully scaleable, then the same solution can be applied to the individual customer or individual generator, the seams between control areas or ISOs, and the interconnection as a whole.

XIII. The Single Meter Problem

When defining the differences between real-energy services, it becomes apparent that energy service differences are due to the variability and timing of energy supply or use. These differences apply to both the block energy services and the sub-hourly RS. The delivery of a single real-energy service is easily measured. However, problems arise when concurrently scheduling delivery for more than one service from a single generator or to a single customer. Each will have only one meter or set of meters to measure the delivery of all services. Consequently, if there is delivery error, a difference between scheduled and actual delivery, there will only be one delivery error measurement available because there is only one metered value. The problem of how to distribute this singular delivery error among the multiple schedules for energy services is the Single Meter Problem [6][7] shown in Figure 1.

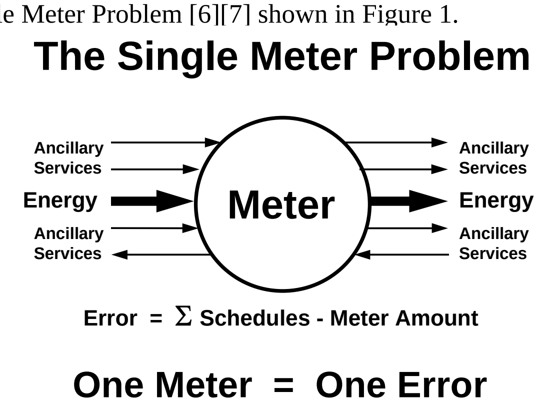

Fig. 3. The Single Meter Problem – presents the problem of determining the value of error from multiple schedules delivered through a single meter.

Restated, how should the error term from a delivery schedule for multiple services distribute among those services? The rule set resolving this problem equitably could be quite large and complex. An alternative statement of this problem is related to the pricing of energy errors. If the form or shape of unscheduled energy from a generator is exactly the same as from a load, the price should be exactly the same because the effect on the system is exactly the same. Efficient markets in these services require a simple solution to this problem. Open energy market development requires efficient management of the errors that will occur during the delivery of energy services. This need arises from the desire to assign costs for error management in proportion to delivery error. Most markets apply an average uplift charge to assign these costs thus disabling price signals delivery error might carry instead of solving the Single Meter Problem.

XIV. Solving The Single Meter Problem

The Single Meter Problem must be solved under two conditions. It must be solved for the Balancing Authority and it must be solved for the generator or load. Different solutions are required because the there are differences in responsibility to perform frequency control.

A. The Balancing Authority Solution:

Fortunately, the Single Meter Problem for Balancing Authorities (BAs) was solved decades ago. That solution resolved the problems associated with the singular delivery error by putting all error into a single term and managing that term as though it was an additional service. That single delivery error term for managing the errors between BAs on the interconnections is Area Control Error (***ACE***). The ***ACE*** Equation (1) defines the frequency control responsibility of Balancing Authorities. The first term is the error between scheduled and actual demand. The second term is a dynamic megawatt responsibility that varies with frequency error. It is another schedule and could be included in the first term, but that would reduce the clarity of responsibility defined. The Frequency Response term of the ACE equation represents a scheduled interchange between the Balancing Authority and the interconnection for which Balancing Authorities do not receive compensation.

$$ACE = \Delta T - 10B(F_A - F_S) \qquad (1)$$

Where: ACE = Area Control Error
B = Frequency Bias
F_A = Actual Frequency
F_S = Scheduled Frequency

The ***ACE*** Equation is still the appropriate measure for determining responsibility for interconnection frequency control. It resolves the Single Meter Problem for Balancing Authorities. It represents the error in control for a Balancing Authority as a singular delivery error, resulting from the difference between many concurrent schedules and only one net actual delivery as measured by a set of meters. Unfortunately, ***ACE*** does not resolve the entire problem. ***ACE*** does not provide a price signal. ***ACE*** is used only for real-time control and performance measurement. For example, ***ACE*** errors accumulate, but those errors are paid back only with in-kind services. Fortunately, ***ACE*** is used as a performance measurement and has been investigated for many of the same characteristics that will be required to make the transition to the risk domain and to develop market prices.

B. CPS1 Information:

The Control Performance Standard (CPS1) developed by NERC in the mid-1990s provides an important part of the solution to the Single Meter Problem. It provides a valid measure of the effect of ***ACE*** contributions to interconnection reliability risk. It weights ***ACE*** by the coincident frequency error on the interconnection in a covariance measure that transforms ***ACE*** in the energy domain into equivalent risk in the risk domain. It includes the term ACE x Frequency Error which is normalized by the frequency control responsibility the BA has accepted with its reliability responsibility. Interconnection frequency error is included in the CPS1 measure because it measures the total net imbalance error on the interconnection. Equation (2) defines the CPS1 Criteria.

$$Average\left\{\left(\frac{ACE}{-10B}\right)_1 \times \left(F_A - F_S\right)_1\right\} \le \varepsilon_1^2 \qquad (2)$$

Where: The 1 subscript indicates 1 minute averages.
ACE = Area Control Error
B = Frequency Bias
F_A = Actual Frequency
F_S = Scheduled Frequency
ε_1 = 1 Minute Average Frequency Error Limit

If this equation is a valid indication of the reliability risk contribution of a BA to the interconnection, it can be used as a basis for transforming energy error into risk contributions due to that error. These risk contributions can determine an equal lambda solution in the risk domain. This is important because risk varies over time and it is total risk that is important in reliability analysis. Additional risk in one time period can be offset by reduced risk in another. Any solution in the risk domain must recognize this characteristic of the problem.

Figure 3 – Equal Risk Profiles – plots the set of equal risk profiles as defined by the NERC CPS1 Criteria on an ACE versus Frequency graph.[8] These profiles provide the basis for converting from the energy domain to the risk domain when valuing unscheduled energy.

C. The NERC IOS Contribution:

One of the problems that the NERC Interconnected Operations Services Task Force faced was how to value the risk error associated with the delivery of Interconnected Operations Services (NERC's Ancillary Services). It was recommended that the removal of the Frequency Bias obligation would convert the CPS1 equation into a function that would properly value uninstructed deviations.[9] The recommendation is shown in (3).

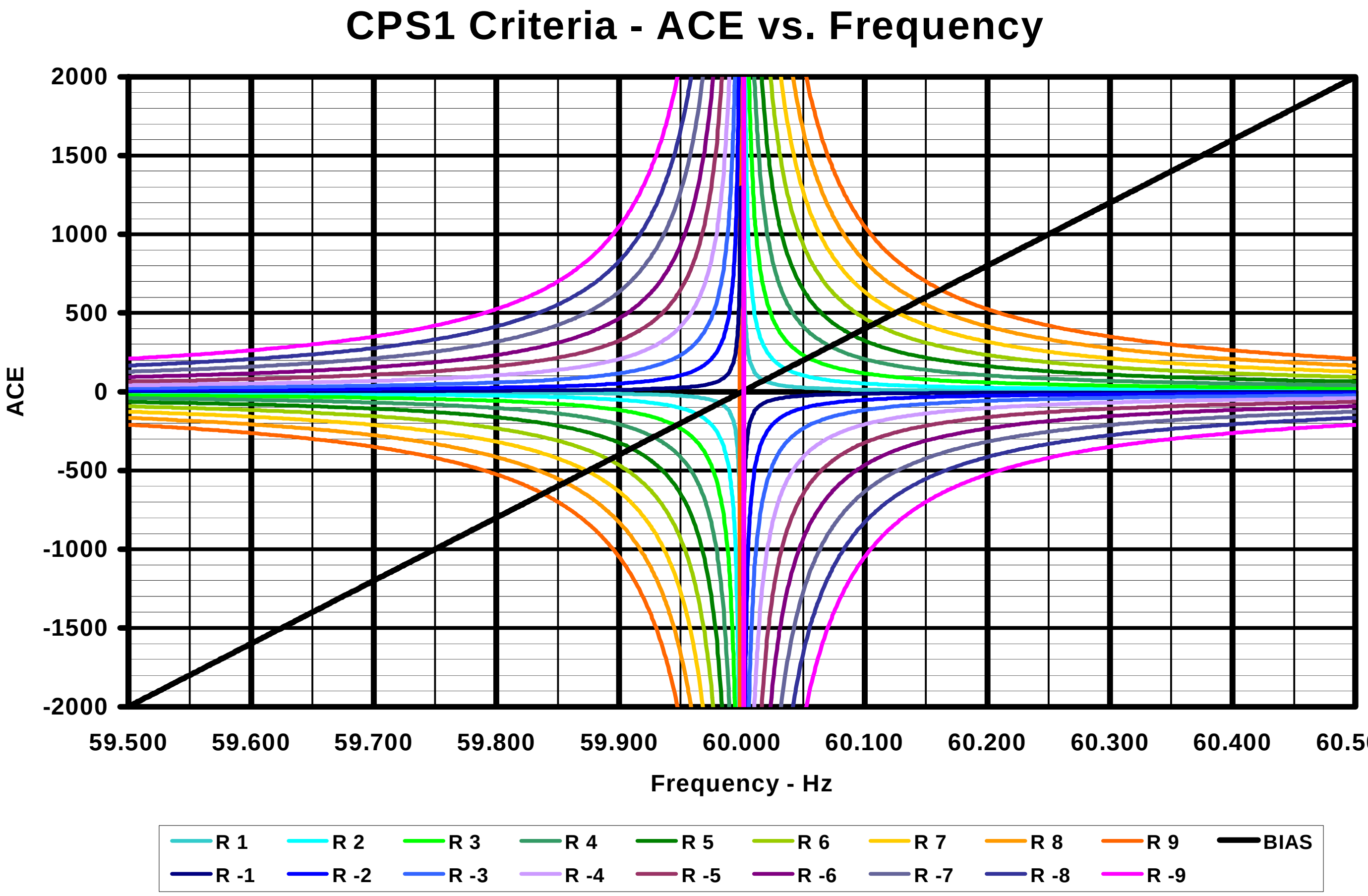

Fig. 3. Equal Risk Profiles – are plotted from the CPS1 Criteria on an ACE versus Frequency graph.

$$\frac{\textbf{Average}\left\{\left(\mathbf{E_U}\right)_1 \times \left(\mathbf{F_A} - \mathbf{F_S}\right)_1\right\}}{\textbf{Average}\left(\mathbf{F_A} - \mathbf{F_S}\right)_1^2} \approx \textbf{AverageRisk} \quad (3)$$

Where: The 1 subscript indicates 1 minute averages.

E_U = Unscheduled Energy

F_A = Actual Frequency

F_S = Scheduled Frequency

This result was the first indication that the solution could be scaled from a NERC BA to unscheduled energy in general. Although it was accepted by the IOS Task Force, it was not included in task force recommendations.

D. The NERC JIITF Recommendation:

In 2001 the NERC Joint Inadvertent Interchange Task Force was given the task of mitigating the financial advantages that derive from the practice of settling Inadvertent Interchange by the payback of energy in-kind. That task force completed its work in 2002 with the recommendation that Inadvertent Interchange consisted of three components.[10] The first component, the Energy Component, represented the value of the energy included in the Inadvertent Interchange and is represented in the energy price. The second component, the Transmission Component, represents the reliability value of the transmission congestion and in present markets this is also included in the energy price. The third component, the Frequency Control Component, represents the value of the response and underlying reserves used to deliver the balancing energy necessary to offset unscheduled energy. It could be effectively measured by the covariance of the energy and frequency error multiplied by a price representing the per unit value of the total risk costs incurred as an extension from the work on NERC CPS1 and the NERC IOS. This Frequency Control Component was recommended for inclusion in a paper prepared for this task force.[11]

E. Determining Per Unit Risk Cost

In late 2002 a method to estimate the per unit risk on an ex-ante basis was developed as part of a contract with ERCOT. That work is yet to be published. In essence, the total risk is directly proportional to the actual RMS value of the frequency error for an interconnection. This value is reasonably stable because the annual average frequency error is reasonably stable. Therefore, the per-unit price can be estimated from the total revenues allocated to ancillary services, including the lumpy components, divided by the annual RMS Frequency Error for the interconnection. Although this value will change over time, it provides a stable insurance risk estimator.

F. Including Transmission Reliability

The final pieces of the puzzle were developed in conjunction with the North American Energy Standards Board (NAESB) as documentation for the Inadvertent Interchange Payback

Task Force (IIPTF). These three pieces are described in technical papers prepared for this task force.

The first paper [12] supports the use of a concept called "Native Market Pricing" that uses the prices of working markets to properly represent the correct prices even under the conditions when those markets are not integrated under a single market solution engine. The assumption in using native market pricing is that even if transmission or trading constraints are not explicitly solved for in an integrated market, if the transmission constraint is enforced, the market prices on opposite sides of the constraint will diverge by the correct amount to properly represent the effect of that transmission constraint. Therefore, this method can be used across seams, between traditional control areas or across ISO seams, as long as the constraints associated with those seams are enforced in an effective manner. This leaves it up to the market to find the optimal solution to the allocation of the available transmission transfer capability.

The second and third papers [13][14] demonstrate that if the revenue imbalance created by this Native Market Pricing method is then uplifted back to the parties in proportion to their contribution to the Inadvertent Interchange (unscheduled energy), the marginal price that results will support the constraint pricing. This result is important, because it demonstrates that a central market engine may not be required to effectively support locational pricing in a market that prices inadvertent interchange correctly. It also demonstrates that over-recovery or under-recovery may not be required to provide good marginal price signals. This conclusion can also be extended and generalized to unscheduled energy.

G. Generalizing the Solution:

The final step in generalizing this solution developed for Inadvertent Interchange is to demonstrate that the same solution can be applied to unscheduled energy in general including Energy Imbalance. This paper is the first to recommend that there are no assumptions or limitations used in these methods that would prevent them from valuing unscheduled energy on a basis that is fully scaleable from the smallest customer to the largest ISO.

XV. The Transition to Adequacy Pricing

The most promising path to market provided adequacy and security is the proper pricing of unscheduled energy. Correct pricing in real-time can drive the forward market to assure both the adequacy and response required to operate a secure system. The reliability that is necessary for the markets in this commodity results from that secure system.

Unfortunately, the path suggested in this paper results in an *average price solution* that is correctly allocated in proportion to marginal risk. The best solution would be a *marginal price solution* allocated in proportion to marginal risk. Therefore, these alternatives can only provide an intermediate stop on the way to finding a full solution for the electricity markets. However, it is an important step because it moves the industry forward and provides a learning platform that can result in acquiring the knowledge to make that last step from average to true marginal pricing of reliability in an electricity market.

XVI. Required System Operator Function

Although the above may provide a path to insure adequate capacity on the system to support reliability, the function of the system operator is still required to insure the efficient transition from adequacy to reliability. Early designs have failed to integrate this function into the market. Current designs of Day Ahead Markets and Multi-settlement allow more of the operator function to be integrated, but still fall short. Significant additional work must be done on market design to integrate the operator function completely and effectively into the market structure.

XVII. Research and Development Needs

The following are the most important research and development needs to successfully complete restructuring of the electric industry into competitive markets.

1. Does overlapping the dispatch of energy with ancillary services in real-time result in indeterminate market energy prices?
2. Should the energy-only market definitions be retained or should the ancillary services be integrated into the market as options?
3. Does the integration of ancillary services into the market as options allow mitigation of hockey-stick bidding?
4. What is the most effective way to integrate the system operator function into the market design?
5. Can the correct pricing of unscheduled energy drive a forward market in energy that will support adequacy?
6. How can an unconstrained market be designed to assure adequacy?
7. How do reliability requirements for an interconnection vary with interconnection size?
8. When do constraints begin to result in differences in reliability between the constrained region and the remainder of the interconnection?
9. How do the reliability needs of a constrained region of an interconnection differ from the reliability needs of the total interconnection?
10. How should constraints affect the pricing of ancillary services within and outside the constrained region?
11. Can a market be designed without a centralized solution engine to calculate the prices for the market?

Most of these needs require that the industry take research a step backwards and solve the unconstrained market problem, before returning to apply what we learn to the transmission constrained markets. This will not be popular, but without understanding the unconstrained market first, we will only be guessing at the consequences of constrained market solutions. If this step is not taken, the alternative will be the implementation of non-market solutions to the problems of adequacy and integration of the system operator function.

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BIOGRAPHY

Howard F. Illian graduated from Carnegie Institute of Technology (Carnegie-Mellon University) in 1970 with a B.S. in Electrical Engineering. From 1970 until 1976 he worked for ComEd in the field of Operations Research, and was Supervisor, Economic Research and Load Forecasting from 1976 until 1982 when he was assigned to Bulk Power Operations where he was Technical Services Director when he retired in 1998. He is now President of Energy Mark, Inc., an energy market consulting firm specializing in defining the commercial relationships required by restructuring. He has authored numerous papers in the field of Engineering Economics, and has testified as an expert witness before the Illinois EPA, the Federal EPA, and the Illinois Commerce Commission. He has developed and applied several new mathematical techniques for use in simulation and decision making. He has served on the NERC Performance Subcommittee, the NERC Interconnected Operations Services Implementation Task Force, the NERC Joint Inadvertent Interchange Task Force, and the NAESB Inadvertent Interchange Payback Task Force. Recent work includes significant contributions to the development of the new NERC Reliability Standards and a suggested mathematical foundation for control based on classical statistics. His current research addresses the development of unscheduled energy pricing, and the related definitions for Ancillary or Reliability Services.