Exhibit No. ISO-17

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PREPARED DIRECT TESTIMONY OF

STEVEN E. STOFT

ON BEHALF OF

ISO NEW ENGLAND INC.

DOCKET NO. ER03-563-030

AUGUST 31, 2004

SUMMARY OF DIRECT TESTIMONY OF DR. STEVEN STOFT

The basic purpose of an installed capacity market is to secure an appropriate level of investment in generating assets to maintain reliability and to acquire that capacity at just and reasonable rates. By making the capacity market locational, investors will be induced to build generation in the regions where it is most needed, and loads in those regions will pay just and reasonable rates for procuring reliability. It is also the best approach for reducing market risk, and also reduces market power. The ISO's current market structure does not achieve this result in part because it does not properly value reliability.

In establishing the demand curve, the following principles are proposed:

The cost of new entry and a determination of the minimum reliable level of installed capacity, Objective Capability (OC), should determine the height and slope, not value of lost load (VOLL), because VOLL is not easily calculated, and would lead to a demand curve that becomes almost vertical. This imposes the very type of risks on investors that the Commission sought to correct in the current ICAP market and to avoid with the sloped demand curve.

The determination of OC is a process that has been practiced and refined for over 35 years in New England. The cost of new entry, called the estimated benchmark cost of capacity (EBCC) by Dr. Stoft, is the annualized fixed cost of the Benchmark Generator. Based on the testimony of John Reed, another of the ISO's witnesses, a frame gas-turbine generator is chosen as the Benchmark Generator in all regions. This type of generator has the lowest total installed cost (and highest variable cost) of the types of generators likely to be built.

Dr. Stoft has selected 15% above OC, which is 9.1% above the historical average level, C_{Target} for the point at which the ICAP price should fall to $0. The zero-capacity level will be adjusted over time in accordance with observed stability of the level of installed capacity under the Locational ICAP market. For capacity levels below OC, the Locational ICAP price is flat at twice EBCC. This is because twice the EBCC is high enough to send a very strong investment signal.

This demand curve is intended to induce the market to keep the level of installed capacity at C_{Target} on average, which should result in capacity levels below OC in only about 15% of the years. When the market has a little excess capacity but when very little investment is being undertaken, the demand curve will send a signal to induce investment in a timely fashion. Conversely, when investment is undertaken, investors will be able to discern its cost-depressing consequences more clearly in advance and thereby avoid the type of overbuilding that has occurred in the recent past.

Inframarginal revenues for the Benchmark Generator are subtracted from the generator's Locational ICAP payment. In addition, Locational ICAP generators will be evaluated during Critical Hours and paid for the percentage of production during these hours to assure that necessary reliability is achieved in accordance with the Commission's directive.

All generators – not just new generators – will receive payments under the Locational ICAP proposal. The policy of paying all generation that provides the necessary service sends the strongest signal to new investors.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power LLC, *et al.*) Docket No. ER03-563-030

DIRECT TESTIMONY OF

STEVEN E. STOFT

1. Introduction:

Q: PLEASE STATE YOUR NAME AND ADDRESS.

A: My name is Steven E. Stoft. My office is located at 2910 Elmwood Court, Berkeley, California, 94705, and my e-mail address is steven@stoft.com.

Q: ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A: I am filing testimony on behalf of ISO New England Inc. (the "ISO").

Q: WHAT IS YOUR BACKGROUND IN THE ENERGY INDUSTRY?

I am a professional economist with fifteen years' experience in the study of economic issues relating to electricity products and markets. A copy of my curriculum vitae is attached hereto as Exhibit ISO-18. In brief, I am the author of Power System Economics: Designing Markets for Electricity (2002, Wiley-IEEE Press), a comprehensive treatise on the theory and practice of power market design. I have also published dozens of scholarly papers and reports on issues related to electricity markets, a list of which is included in Exhibit ISO-18. I have been invited to speak on electricity market issues before the National Science Foundation, the World Bank, the Federal Energy Regulatory Commission

("FERC" or "Commission"), the Edison Electricity Institute, the U.S. Department of Energy and others. I have held appointments with FERC's Office of Economic Policy, where I worked with Dick O'Neill's consultants on advanced market-design issues and reviewed the startup filing of the New York Independent System Operator ("NYISO"), with the Lawrence Berkeley National Laboratory, and with the University of California Energy Institute. In addition, as a self-employed professional consultant, I have advised public utilities, private power companies, and governmental entities on electricity market issues. Since September 1999, I have been a paid advisor to PJM's Market Monitoring Unit.

Q: HAVE YOU PREVIOUSLY APPEARED AS AN EXPERT WITNESS IN OTHER ENERGY INDUSTRY LEGAL PROCEEDINGS?

A: Yes. I have appeared on behalf of generators in two proceedings before the Alberta Electric Utilities Board, and on behalf of the California Electricity Oversight Board before FERC.

Q: WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A: It will answer the Commission's questions regarding the structure and use of the Locational ICAP demand curve, as set for hearing by the Commission in its Order on Compliance Filing and Establishing Hearing Procedures in *Devon Power, LLC, et al.,* 107 FERC ¶ 61,240 (2204) ("June 2 Order"). To do this properly it will be necessary to explain many details of that market, and the design approach used to develop the demand curve.

It will describe the role of a demand curve in the short and long-run Locational ICAP markets.

It will describe the role of the demand curve in the context of the larger Locational ICAP market design, including the Locational ICAP auction, availability testing of purchased Locational ICAP capacity, and monthly adjustments to the demand curve.

It will describe the treatment of inframarginal revenues and benchmark cost of capacity ("BCC") in determining the demand curve and Locational ICAP payments.

At the end of my testimony I have included a glossary defining the technical terms and abbreviations I will use throughout my testimony.

Q: PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY AND CONCLUSIONS.

A: The simplest means of providing such a summary is to address the questions raised by the Commission in its June 2 Order and, as appropriate, to address certain other Locational ICAP benefits that result from the design of an efficient, effective market.

Q: WHAT IS THE PURPOSE OF AN INSTALLED CAPACITY MARKET?

A: Although this is not an issue set for hearing, it is helpful to begin our presentation with a brief discussion of the installed capacity market because it will aid our analysis of the issues that have been set for hearing. The basic purpose of an installed capacity market is to secure an appropriate level of investment in generating assets to maintain reliability and to acquire that capacity at just and reasonable rates.

Q: WHAT IS THE RATIONALE FOR ADDING THE LOCATIONAL COMPONENT TO THIS MARKET?

A: By making the capacity market locational, investors will be induced to build generation in the regions where it is most needed, and loads in those regions will pay just and reasonable rates for procuring reliability.

Q: CAN A LOCATIONAL ICAP MARKET SERVE OTHER PURPOSES WHILE FULFILLING THE BASIC RELIABILITY PURPOSE?

A: Yes, in fact a primary reason for choosing the Locational ICAP market approach to reliability is that it is the best approach for reducing market risk, and also reduces market power. In the long-run, this may well save consumers more money than the improvement in reliability.

Q: CAN THE ENERGY MARKET UNDER NEW ENGLAND'S STANDARD MARKET DESIGN SUSTAIN A RELIABLE LEVEL OF INVESTMENT?

A: No. Currently, the energy markets are not likely to provide sufficient opportunity for return on investment when the installed capacity level drops to the level required for reliability. Consequently, the necessary level of installed capacity cannot be sustained.

Q: CAN YOU EXPLAIN WHY THE NEW ENGLAND'S ENERGY MARKET IS NOT LIKELY TO SUCCEED AT SUSTAINING THE NECESSARY INVESTMENT?

A: It is difficult to explain why it will not succeed without understanding what is required for success. Fortunately, there is a classic market design that describes what is needed, although it is an impractical design for a number of reasons.

Q: PLEASE DESCRIBE THIS IDEAL, BUT IMPRACTICAL DESIGN THAT YOU WOULD LIKE TO USE AS A STANDARD FOR COMPARISON?

A: The Classic Value-of-Lost-Load ("VOLL") Design is a market that sets the spot price of energy at the intersection of the supply curve and the demand curve except when they do not intersect, and then it sets the spot price to the value of lost load. Although this design is not practical, it could be implemented rather approximately, and it would work, though somewhat crudely and with significant risk, if allowed to do so. It is hampered by one impractical input and three unfortunate side effects as follows:

1. VOLL cannot be accurately determined.
2. The Classic VOLL Design's extreme spot prices create costly market risk.
3. The Classic VOLL Design's VOLL pricing creates too much market power.
4. The Classic VOLL Design's occasional extremely large payments by load to generation may well lead to political intervention.

For now I will ignore these shortcomings and focus on the benefits of its core structure. This design allows the market to determine the correct investment level for optimal reliability, and it is a genuine market solution with one exception. The market cannot determine VOLL; that number must be set by the regulator or the market administrator. VOLL is the value of avoiding one MWh of unreliability, and the market tells us nothing at all about this input.

Still, the Classic VOLL Design is theoretically attractive because it allows the market to determine exactly how many generators should be built to properly trade off consumer satisfaction—blackouts vs. cost of electricity.

Q: NOW CAN YOU EXPLAIN WHY NEW ENGLAND IS NOT LIKELY TO SUCCEED AT SUSTAINING THE NECESSARY INVESTMENT WITH ITS CURRENT ENERGY MARKET DESIGN?

A: The energy markets in the Northeast and Midwest, including New England's, differ from a Classic VOLL Design in two important ways:

1. They cap prices at (typically) $1000/MWh which is perhaps 10 to 30 times less than VOLL.
2. They raise price above the intersection of supply and demand, especially when supply runs short.

Consider, as an example, a 1-Megawatt generator with a need to recover $90,000/year of fixed costs and with a variable cost of $75/h when it produces its full MW of output. Suppose, for simplicity, that it has the highest marginal cost of any generator in the system, and that VOLL = $30,000/MWh.

Now consider what would happen to this generator under the Classic VOLL Design. If the system had too much capacity, by a certain amount, this would cause, on average, only one hour per year in which load was shed. So our generator would recover only $30,000/year and would be $60,000 short of recovering fixed costs.

If the system had too little installed capacity, by a certain amount, there would be 10 hours per year on average of load shedding and it would recover 10 × $30,000 of fixed costs or $210,000/year more than it needs. When the market is this short of capacity more such generators would be built and when fixed cost recovery was down to one hour per year, none would be built. The balancing point comes when VOLL price spikes exactly recover fixed costs, which is at three hours per year of load shedding.

A VOLL market automatically brings the level of capacity to the optimal level for reliability and, because the market has voluntarily adjusted to this level, all generators including our 1-Megawatt generator recover their fixed costs and break even.

In this simple example, I will assume that when load is shed every generator in the system is operating at full capacity. Consequently, these VOLL price spikes are paying $90,000/MW-year to every single generator in the system. Economics has proven that this is required as an adder to normal inframarginal rents (short-run profits) to cover the fixed cost of every generator in such a system. With these price spikes they all just break even.

The first difference, listed above, between the New England market design and the Classic VOLL Design is that the New England design, when applied to this example, takes away $90,000 per MW per year for cost recovery needed by every generator in the system. With 25,000 MW of capacity, that comes to a $2.25 billion per year shortfall. The generator in our example would recover none of its costs of owning a generator; it can only pay for fuel and variable operations and maintenance.

New England and other markets recognized this is a problem and have various methods of raising the price above the intersection of the supply and demand curves. The most important of these in New England is the shortage payments.[1] These will pay back some of the $90,000/MW-year. In the last year there were shortages in only about three hours, but in a year with optimal installed capacity there might be 30 shortage hours (these are much more frequent than load-shedding hours), and so our 1-Megawatt generator might earn 30 × $400, or $12,000 ($400 being a typical shortage price increase). This is slightly less than $90,000, so it would be better off, but still rather short of full fixed cost recovery.

If this example were correct, and I believe it is qualitatively correct, the 1-Megawatt generator would recover less than 15% of its fixed costs when there was just the right amount of installed capacity. Because this generator is rather similar to ones that need to be built to maintain reliability, the conclusion must be that the signal to invest, under the current design, is much too weak, or rather, that it is a signal not to invest until New England has far too little installed capacity.

Q: HOW DOES THE PROPOSED DESIGN IMPROVE ON THE CURRENT MARKET DESIGN?

A: First, the proposed Locational ICAP market solves the problem of inducing the correct level of installed capacity in each of New England's Locational ICAP Regions. Second, the proposed design dramatically reduces risk for both investors and customers. Reducing risk for investors reduces their risk premiums and this savings will be passed onto consumers by a competitive market. Third, it reduces market power during times of shortage—the times at which it is most problematic. Taken together, these features of the proposed design will minimize long-run consumer costs, including all costs of generation and the cost of possible blackouts from inadequate generation capacity.

Q: IN ITS JUNE 2 ORDER, THE COMMISSION APPROVED THE USE OF A DOWNWARD SLOPING DEMAND CURVE FOR LOCATIONAL ICAP AND ASKED: "SHOULD THE HEIGHT AND SLOPE OF THE CURVE BE BASED ON THE COST OF NEW ENTRY OR ON OTHER FACTORS, SUCH AS AN ESTIMATE OF THE RELIABILITY VALUE TO LOADS OF ALTERNATIVE LEVELS OF CAPACITY, AND IF THE LATTER, WHAT ARE REASONABLE ESTIMATES OF SUCH RELIABILITY VALUES?"

A: Let me start by clarifying the term "value." Its use by the Commission is essentially the same as is its use in "value of lost load." Both refer to the value to consumers of avoiding a loss-of-load condition. That relationship is crucial,

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[1] Shortage payments increase the price of energy by various amounts ($200, etc.) when there are various

but it is also crucial to understand that this question does not concern a VOLL energy market (such as described earlier) or the comparison of such a market with a Locational ICAP market.

The Commission's question concerns the ICAP markets and two methods of constructing the demand curve for an ICAP market—one based on the cost of new entry and the other based on VOLL. Essentially, this question asks, should VOLL and probabilities of lost load be used to draw an ICAP demand curve, or should the cost of new entry be used to draw that curve?

I will refer to these two fundamental approaches as the cost (of new entry) approach, and the value (of lost load) approach. To compare them fairly it must be noted that the cost approach requires one other crucial and difficult input, Objective Capability ("OC"), the minimum acceptable capacity level for reliability. In spite of this difficulty (which pales in comparison to the difficulty of estimating VOLL), the cost approach is far superior to the value approach.

In the cost approach, the demand curve's position is determined by the cost of new entry (which I will refer to as Benchmark Cost of Capacity or BCC) and OC together. In contrast, the value approach requires as an administrative input, VOLL, because reducing the chance of lost load is what makes marginal capacity valuable to consumers.

In theory, developing a demand curve based upon the value of lost load to consumers could be the best means of compensating generators with just and reasonable rates paid by consumers. But in practice, this approach has two flaws;

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levels of operating-reserve shortage.

the first makes it nearly impossible to implement and the second makes it less desirable even if implementation were feasible. The first flaw is that the market does not, and cannot, provide an estimate of VOLL; it must be administratively determined. As I will explain later, this determination is extremely difficult, extremely inaccurate and would be extremely controversial since misestimation could lead to inadequate reliability or over-procurement of capacity. The use of VOLL in capacity markets is without precedent.

The second flaw in the value approach to demand curve design is the unnecessary risk this would impose on the market. Just as using a VOLL energy price is extremely risky, so a VOLL demand curve design would produce a demand curve that becomes almost vertical below current OC levels and is extremely risky. This imposes unnecessary costs on investors, who pass them on to consumers, with the result that rates are higher than necessary and therefore not just and reasonable.

In contrast, the cost approach relies on a determination of the minimum reliable level of installed capacity, OC. The determination of OC is a process that has been practiced and refined for over 35 years in New England. For these reasons, the cost approach should be used and a VOLL-based Locational ICAP demand curve should not be used.

Q: WHAT IS THE "BENCHMARK COST OF CAPACITY"?

A: BCC, previously called the cost of new entry ("CONE"), is the annualized fixed cost of the Benchmark Generator. John Reed, another of the ISO's witnesses, testifies that a frame gas-turbine generator has the lowest fixed cost per

Megawatt of capacity, of any type of generation that the market will build. (Economics terms generators that are worth building, "economically efficient.")

Not surprisingly, this unit also has the highest variable cost of any economically efficient technology. This means its inframarginal rents are smallest, and in dollar terms, most accurately estimated. Using this particular generator as the benchmark gives the most accurate Locational ICAP Payments, so I am using frame gas turbines as the Benchmark Generator in all regions.

John Reed has estimated the annualized cost of a frame gas turbine for each of the Locational ICAP Regions and these estimates, called Estimated Benchmark Cost of Capacity ("EBCC"), will inevitably differ slightly from the true value, BCC. In the Rest-of-Pool Region, EBCC is $7.70/kW-month

When installed capacity equals a value I call C_K, the Locational ICAP demand curve is defined to pay an actual frame gas turbine its fixed costs, BCC, as nearly as possible. This would seem to mean paying its EBCC, but because both the energy market and the proposed ICAP market pay generators only when they are available, the actual frame unit would recover less than BCC and its potential investors would not be motivated to invest. This will be corrected in the Market Rules by replacing EBCC with EBCC divided by a benchmark-availability rate, *e.g.* 90%. To avoid unnecessary complexity, this adjustment will not be made explicit in the remainder of my testimony, but it should be remembered that EBCC will include it when the market is implemented.

Q: THE COMMISSION GOES ON TO ASK: "SHOULD THE LOCATIONAL ICAP PRICE REFLECT THE COST OF NEW ENTRY (NET OF

INFRAMARGINAL ENERGY REVENUES) WHEN CAPACITY EQUALS (I) OBJECTIVE CAPABILITY, (II) THE HISTORICAL AVERAGE LEVEL OF CAPACITY RELATIVE TO OBJECTIVE CAPABILITY, OR (III) SOME OTHER LEVEL?"

A: First let me clarify our approach to the treatment of inframarginal energy revenues, which differs slightly from the Commission's formulation in its question. In the current design, the Locational ICAP Payment equation **is**

LP = P – PER. (PER stands for Peak Energy-Market Rents.)

This means the "Locational ICAP Payments" ("LP") equal the "Locational ICAP Price" ("P") given by the "Locational ICAP Demand Curve" minus the inframarginal rents ("PER"). By answering this question for the Locational ICAP Price, P, I will avoid the confusion of inframarginal rents while being faithful to the intent of the question.

My answer is that the Locational ICAP Price should reflect the cost of new entry when capacity is at a point between OC and the historical level of capacity relative to OC. Symbolically represented:

OC = Objective Capability

C_K = The capacity at which the Locational ICAP Price reflects (equals) the cost of new entry (now BCC).

C_{Target} = The historical average level of capacity relative to OC

$$\mathbf{OC < C_K < C_{Target}}$$

All three of these values, recognized here by the Commission, play key roles in the design of the demand curve. The method used to pick C_K is to choose it so that investors will recover BCC on average when they provide C_{Target} of capacity on average.

Later, when I explain the demand curve in more detail, I will explain why it is necessary to select an intermediate value of C_K in order to make the Locational ICAP Price, P, equal BCC on average, when installed actual capacity is averaging the selected target level of capacity.

Q: NEXT, THE COMMISSION ASKS: "AT WHAT CAPACITY LEVEL SHOULD THE LOCATIONAL ICAP PRICE FALL TO $0?"

A: In the consultation with the ISO, the capacity level selected for a $0 Locational ICAP Price is 15% above OC and 9.1% above the historical average level, C_{Target}.[2] The zero-price capacity level (C_{Max}) will be adjusted over time in accordance with observed stability of the level of installed capacity under the Locational ICAP market. If the market becomes more stable as anticipated, the capacity level at which the Locational ICAP Price falls to zero will be decreased.

These values are derived from the considerations discussed in my previous answer and one additional design parameter: the ratio of the slope to the left of C_K to the slope on the right. This ratio has been set to three.

Several economic considerations have gone into the determination of C_{Max} and the slope ratio. Additionally, in his testimony, ISO witness Mr. LaPlante discusses some policy considerations that have also been included in developing this level.

[2] It should be noted, that due to the subtraction of benchmark inframarginal rents from the Locational ICAP price, Locational ICAP payments will fall to $0 at a level that is lower by perhaps something in the neighborhood of 1%.

Some considerations push in one direction and some in the other, so a tradeoff was made after carefully considering the following factors. First, a high value of C_{Max} is desired to minimize investment risk by providing some Locational ICAP payments even in times of capacity surplus. Second, a low value of C_{Max} is desired so that proper retirement signals are not unduly impeded. Third, a low C_{Max} is desired to make the demand curve steep, allowing it to accurately determine C_{Target}. Fourth, a higher value of C_{Max} might require allocating Locational ICAP payments to shortage hours in years which had no shortage hours.

Q: PLEASE BRIEFLY DISCUSS THE SHAPE AND SLOPE OF THE DEMAND CURVE YOU RECOMMEND.

A: The demand curve is necessarily based on an EBCC and not the actual BCC, which cannot be known precisely.

As just discussed, to the right of C_{Max}, which is about 15% above OC, the demand curve is flat at $0/kW-month.

For capacity levels below OC, the Locational ICAP Price is flat at twice the EBCC. This is because twice the EBCC is high enough to send a very strong investment signal. Any stronger signal might cost consumers more than the benefits they receive from the added investment.

Between OC and C_{Max} are two sloped regions. The left region, up to C_K, is three times steeper than the region to the right of C_K. The steep left region helps prevent low values of installed capacity, which could threaten reliability, and the flatter right region helps reduce investor risk.

It is important to note that other, slightly different, demand curves could work as well as the one presented here. For such a demand curve to work well, the ceiling must be high enough to prevent much chance of installed capacity falling below OC to avoid market interventions. The level of C_K must be set to induce the relative historical level of capacity denoted by C_{Target}. The right slope should be significantly less than the left slope, to reduce investor risk while protecting against dangerously low values of installed capacity. The level of C_{Max} should neither be so high as to discourage proper retirements nor so low as to impose excessive risk. Within these guidelines and a few less important ones, there is still room for judgment.

Q: PLEASE PROVIDE THE GRAPHIC DEPICTION OF THIS CURVE.

The demand curve described above appears as follows:

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Q: WHAT INCENTIVES AND/OR PRICE SIGNALS IS THIS DEMAND CURVE INTENDED TO SEND?

A: This demand curve is intended to induce the market to keep the level of installed capacity at C_{Target} on average, which should result in capacity levels below OC in only about 15% of the years. When the market has a little excess capacity but when very little investment is being undertaken, it will send a signal that fixed-cost recovery will soon begin to increase fairly rapidly. The ability to forecast high prices accurately will send a strong investment signal before shortage conditions are realized. This signal should induce investment to be undertaken in a timely fashion. Conversely, when investment is undertaken, investors will be able to discern its cost-depressing consequences more clearly in advance and thereby avoid overbuilding.

The stability and predictability of this market will send a message that there is relatively little market risk.

Q: THE DEMAND CURVE IS BASED ON ESTIMATED BCC. WHAT HAPPENS IF THAT ESTIMATE IS TOO HIGH?

A: That is best described with the help of the following diagram.

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Note that the effect of raising the demand curve due to an over estimate of BCC is not to increase the long-run Locational ICAP price, but instead to buy more installed capacity. This is costly to consumers, but they do not over-pay for capacity; they only buy too much. The extra purchase of capacity increases their reliability, but this is only partial compensation for the extra cost incurred, so they are worse off than if they had purchased the target level of capacity. Fortunately, buying too much capacity is not very costly for several reasons: <u>peaking capacity is relatively cheap</u>; it uses almost no fuel, and it provides some reliability benefit. Wholesale costs are only a fraction of retail costs, which further dilutes the cost increase.

Q: THE COMMISSION ALSO ASKS: "WHAT IS A REASONABLE ESTIMATE OF THE NET INFRAMARGINAL REVENUES THAT COULD BE EXPECTED FROM THE ENERGY MARKETS, AND DOES THAT REVENUE VARY AMONG REGIONS?"

A: By asking this question, the Commission appears to have implicitly recognized the complexity of the issue and the difficulty of estimating inframarginal revenues in advance. Inframarginal revenues depend on future weather conditions, outages, and exercises of market power. The proposed market design eliminates all of these difficulties and their inevitable controversies. And to answer the last part first, yes, the benchmark inframarginal revenue does vary among regions.

Q: HOW ARE THE DIFFICULTIES OF ESTIMATING INFRAMARGINAL REVENUES AVOIDED?

They are avoided by estimating the inframarginal revenues after the fact. At the end of the Locational ICAP year, every hourly price is known and all that needs to be estimated is the variable cost of the Benchmark Generator, which is a standard-issue generating unit assumed to be in perfect working order at all times. The result will be far more accurate and nearly free of controversy as to the calculation.

Q: BESIDES SIMPLICITY AND ACCURACY ARE THERE OTHER ADVANTAGES TO THIS APPROACH?

A: This approach will greatly reduce if not eliminate market power in the spot market during shortages by subtracting these revenues from the Locational

ICAP demand curve. Thus, if a generator causes an artificial shortage, the maximum profit that the generator could obtain from this shortage will be subtracted from the Locational ICAP demand curve and, consequently, from the generator's Locational ICAP payment. When generators sell Locational ICAP, they essentially give away their motivation to exercise market power during peak hours.

From a generator's perspective, the primary benefit of retrospective estimation is enhanced revenue certainty from Locational ICAP. Whether energy market factors cause relatively few shortage hours and low prices or, conversely, cause abnormally high numbers of shortages and high prices, Locational ICAP revenue plus shortage revenue will remain constant. This reduces risk to generators and, in turn, lowers costs to consumers who will not have to pay the investor's risk premium.

Q: PLEASE EXPLAIN THIS PROCESS OF PAYING HIGH PRICES IN THE ENERGY MARKET AND THEN SUBTRACTING THEM IN THE LOCATIONAL ICAP MARKET.

A: The central point to remember is that Locational ICAP is just a supplement to the energy market. All generators get and keep the same energy market payments as if Locational ICAP did not exist, whether or not they sell their capacity in the Locational ICAP market. If they do sell in that market, then they will usually, but not always, receive a Locational ICAP payment. In no case will this payment be negative.

The “nominal Locational ICAP payment” is computed from the Locational ICAP price,[3] as determined by the Locational ICAP demand curve, by subtracting the “Peak Energy-Market Rents~~.~~,” (“PER”). These rents are the revenues, net of variable costs that the Benchmark Generator would earn if it were always available. Generally this will be positive, but if it is not, it will be set to zero.

Locational ICAP generators will be evaluated during Critical Hours. If their production during these hours averages 90% of the Locational ICAP capacity they sold, then they are paid 90% of the nominal Locational ICAP payment for all of this capacity.

Example: Perhaps this is all best explained with the help of the 1-Megawatt generator example. That generator has a marginal cost of $75, and I will now suppose that the Benchmark Generator has a marginal cost of $80/MWh, and that the Locational ICAP demand curve and installed capacity level have determined a Locational ICAP price of $7/kW-month. To enrich the example, I will also now assume that some Benchmark Generators have been built and the 1-Megawatt generator does not have the highest marginal cost. The equation that is the key to this example is:

Short-run profit = inframarginal energy rent + (P – PER)

Case 1: The Benchmark Generator has inframarginal rents of $2/kW-month and the 1-Megawatt generator has inframarginal rents of $2.10/kW-month. These are close together because when price is above $75 it is on average $100 above so the two earn almost the same rent.

[3] The monthly Locational ICAP price is the price determined by the monthly supply and demand curve

The 1-Megawatt generator's short-run profit is:

$2.10 + ($7 – $2) = $7.10.

This is the generator's energy rent plus its Locational ICAP payment. The Locational ICAP payment is the Locational ICAP Price minus the inframarginal rent of the Benchmark Generator.

Case 2: The year is cool, there are few price spikes, and the generator's inframarginal rent is $0.55, while that of the Benchmark Generator is only $0.50/kW-month. In this case, the generator's short-run profit is:

$0.55 + ($7 – $0.50) = $7.05.

Case 3: The year is hot, a nuclear unit goes out, and price rises. Consequently, the benchmark inframarginal rent goes to $8.00 and the generator's inframarginal rent goes to $8.20. Its short-run profits would become:

$8.20 + ($7 – $8) = $7.20, except that (7 – 8) is negative.

Locational ICAP payments are never negative, so the 1-Megawatt generator's actual short-run profits are:

$8.20 + 0 = $8.20.

To understand the impact on market power of the Locational ICAP payment formula, suppose that the year is cool as described in Case 2, but the 1-Megawatt generator decides to exercise market power in the most egregious way by disabling a competitor's generator. This is the most profitable approach as it avoids the loss of profit from withholding output. Suppose this causes the market price to increase to such an extent that the year's inframarginal rents become those

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times the relative weight of the month's Critical Hours to the year's Critical Hours (as described below).

described in Case 1. Although the generator makes $~~2.05~~**1.55**/kW-month extra for the whole year in the energy market, its short-run profits increase only by five cents, from $7.05 to $7.10. Because Locational ICAP payments are reduced by price increases in the energy market, a generator loses almost as much in Locational ICAP payments as it gains in energy payments when it exercises market power.

Q: YOU HAVE SAID THAT ONE OF THE FUNDAMENTAL PURPOSES OF THE LOCATIONAL ICAP MARKET IS TO INCREASE RELIABILITY. IS RELIABILITY ONE OF THE GOALS SOUGHT BY THE COMMISSION IN LOCATIONAL ICAP?

A: Yes. In its June 2 Order, the Commission stated that its "goal in establishing these hearing procedures is to arrive at a final LICAP market design that will appropriately compensate generators needed for reliability and attract and retain necessary infrastructure to assure long-term reliability." June 2 Order at P1.

Q: HOW WILL LOCATIONAL ICAP ENSURE THAT THE CAPACITY IS RELIABLE, *I.E.*, ACTUALLY AVAILABLE WHEN MOST NEEDED AT TIMES OF SHORTAGE?

A: There are two possible reasons for unavailability at a time of shortage. First, a resource might be exporting power, and second, it might not be producing power. The first problem is solved by the recall option, and the second problem is solved by a combination of a substantial Locational ICAP payment and availability testing that removes the payment if the generator is unavailable in a Critical Hour.

As in the current market, any generator that has sold Locational ICAP will be recallable by the ISO during an emergency. Such a recall is a matter of scheduling by the ISO and does not depend on the cooperation of the generator.

The Locational ICAP market has been designed to assure that selling Locational ICAP is almost always profitable. Even when there is some chance of it being zero there will be a reasonable chance of peak energy rents being less than the Locational ICAP price and thus of the Locational ICAP payment being substantially positive. For this reason, generators will almost always wish to avail themselves of the opportunity to receive Locational ICAP payments.

Once capacity has been sold, the reduction in Location ICAP payments for unavailability will provide a strong motivation for generators to be available during any hour that has a good chance of being one of the Critical Hours.

Locational ICAP payments are made each month in proportion to the number of Critical Hours in the month and in proportion to the criticalness of those hours (see Section 9). Moreover, a generator's availability track-record is an annual calculation and thus missing a Critical Hour in one month affects the entire year's payments. Suppose there are 100 Critical Hours in the year and a generator misses an average-weighted critical hour in August. As a consequence, its Locational ICAP payment will be reduced approximately 1% in every hour throughout the year.

Assume that annual Locational ICAP payments are $60,000 per MW. Missing one typical Critical Hour would result in missing 1/100 of this payment or $600. But, the weights of shortage hours can easily be five times greater than the weight of the average critical hour. In a shortage hour, the missed payment could easily be five times $600, or $3000. Locational ICAP will provide an extremely strong signal for generators to make themselves available when most needed.

The determination of Critical Hours will be based on real-time energy prices, operating-reserve margins, and other relevant factors. Generators will be checked for availability only during these hours. Partial credit will be given for partial availability. Both energy production and provision of reserves is counted towards availability. Provision of reserves will be estimated based on live testing that will be part of the operating reserve market design and contained in the Market Rules for this market. Fewer hours will be tested in years with a large amount of excess capacity and more hours will be tested when capacity is relatively scarce.

Example: Consider case 1 above and assume that the $2/kW-month of benchmark inframarginal rents (PER) occurs over 200 hours. Now $2/kW-month for a year is $24/kW, or $24,000/MW. Therefore, a 1-Megawatt Benchmark Generator would have received $24,000 above ~~in~~ variable costs from high energy prices occurring in 200 deferent hours.

That comes to $120/MW for each of the 200 hours. Suppose half of those are low price-spike hours with rents of $60/MW, and half are high price-spike hours with rents of $180/MW.

Typically only 100 hours will be Critical Hours (ones with Locational ICAP payments) and those would be the high-priced hours.

If the 1-Megawatt generator misses a low-price-spike hour, it would miss $60, which would reduce its inframarginal rents and it would lose $60 in short-run profit in the energy market. Its Locational ICAP payment would be unchanged, since this is not a Critical Hour. Its incentive to generate in low price-spike hours is therefore $60.

If the 1-Megawatt generator misses a high-price-spike hour, it misses out on $180 of energy payments, but it would also miss 1/100 of the nominal Locational ICAP payment which is $7.10/kW-month over the whole year. This adds a large additional incentive.

$7.10/kW-month for a year, is $85.20/kW, which is $85,200/MW. One hundredth of this total Locational ICAP payment is $852/MW. Therefore, by missing a high-price-spike hour, the 1-Megawatt generator missed $180 from the energy market and $852 from the Locational ICAP market. Its total incentive to generate in a high-price-spike hour is $1032/MWh.

Q: YOU HAVE SAID THAT ONE OF THE PRIMARY GOALS OF A LOCATIONAL ICAP MARKET IS "TO SECURE AN APPROPRIATE LEVEL OF INVESTMENT IN GENERATING ASSETS TO MAINTAIN RELIABILITY." IF YOUR GOAL IS TO "SECURE" INVESTMENT, WHY ARE YOU PROPOSING PAYMENTS TO ALL GENERATORS, EVEN IF THEY ARE ALREADY BUILT AND THE INVESTMENT MADE?

A: Stated bluntly, the ISO pays all resources that provide a capacity benefit—whether they are generators or demand response programs—because the ISO's goal is to mimic the price spikes that would be obtained in an uncapped energy market. Economic theory demonstrates that design to be economically efficient and to send the right investment signals. This policy of paying all generation that provides the necessary service sends the strongest signal to new investors. A policy of paying only new generators must be accompanied by a promise that when they are no longer new generators the payments will continue and they will not be treated as existing generators are now treated. Such promises are rightly viewed with skepticism by investors. This would defeat a major purpose of the Locational ICAP proposal, which is to reduce the perception of regulatory risk.

Q: THE COMMISSION HAS ASKED: "TO WHAT EXTENT DO THE PARAMETERS OF THE DEMAND CURVE USED BY THE NYISO AFFECT THE ABILITY OF NEW ENGLAND TO ATTRACT ICAP CAPACITY, AND THUS, HOW SHOULD THE NEW YORK PARAMETERS AFFECT THE PARAMETERS FOR NEW ENGLAND?"

A: New England's Locational ICAP market is designed so that, provided its parameters reflect its own needs, it will neither harm nor be harmed by neighboring markets. It is also designed to allow efficient trade with neighboring regions. The sloped demand curves of New England and New York ensure that prices will adjust to the costs of new entry in both regions. If these costs differ substantially there will be permanent exporting of capacity from the cheaper region, but this will not affect long-run prices.

New England's Locational ICAP market is designed to allow exporting of energy without any penalty on over 97% of annual hours[4] even when its capacity market

[4] At most there will be 200 Critical Hours out of 8760 in a year.

is very tight. During a very few Critical Hours, generation that has sold Locational ICAP to New England will be penalized if it does not also sell its energy to New England, but it will be prevented from exporting only during actual reserve shortages, which are extremely rare. In general, the market design favors annual imports or exports although it allows monthly switching. Annual trades reflect the costs and values of capacity more accurately than do monthly trades, so this is appropriate.

Q: WHAT IS YOUR BROADEST VIEW OF THE LOCATIONAL ICAP DESIGN GOAL AND THE PROPOSED SOLUTION?

A: There are two key goals: to ensure reliability at a just and reasonable cost, and to reduce the cost of risk to a just and reasonable level. Providing reliability at a just and reasonable cost is the easier problem.

Engineers can assess the cost-efficient, OC level with reasonable accuracy, probably with an error of no more than a few percent. Given a target capacity level based on the OC level, it is not hard to arrange for its provision. Simply design a market that makes a credible promise to pay more than the cost of new entry when capacity is short of Objective Capability and less when it is long. The invisible hand of the market will then provide very nearly the right amount of capacity and competition will guarantee a fair and efficient price for it. If the market and decision-makers overshoot the ideal capacity level by 5%, it will cost consumers less than 1% of retail costs.[5]

[5] See the public PJM document, “Normalized Total System Costs vs Reserve Margin” by Javier Inon and Benjamin F. Hobbs, The Johns Hopkins University, August, 2004.

As I will discuss later in this testimony, risk premiums without Locational ICAP might well cost considerably more than any likely error in the market's induced level of installed capacity. In short, optimizing reliability is the easier part of market design and risk-minimization, which benefits all parties, is the more difficult part. It is also the area in which there is most to gain.

For what is essentially an annual market, the proposed Locational ICAP design does a very good job of reducing investor risk. It almost completely removes the weather risk, and other similar annual risks. Even fluctuations in profitability caused by capacity fluctuations are reduced relative to the energy market and previous Locational ICAP designs.

Although most details of the design have of necessity been partially based on expert judgment, it does not appear that even a perfect demand curve could provide a significant additional cost savings on the reliability front. Also, risk premiums should be nearly as low as theoretically possible. Fortunately, these benefits are not particularly sensitive to changes in design parameter values. For example, making the demand curve steeper would increase risk for investors, but the design would remain just as transparent, weather risk~~,~~ would still be fully neutralized, and cost-recovery would still be much less sensitive to installed capacity than under the previous vertical demand-curve system.

Finally, regulatory risk is the Achilles heel of this proposal. The market's success depends entirely on long-run signals that cannot be sent without a credible regulatory commitment. No matter how well designed the demand curve is or how much it pays, if investors believe the rules and/or the demand curve will be materially changed before they build their generators and receive their first payments, they will simply pay little attention. The money paid in Locational ICAP payments would then send a very weak signal.

Without credible regulatory commitment, risk premiums will stay high and consumers will be forced to pay more than necessary. The market has been designed with this in mind. It contains several self-correcting mechanisms to minimize the need for regulatory modification. The design need not be set in stone. In fact, adjustments that increase the accuracy with which it reaches its stated goals will actually increase its credibility.

2. The Role of the VOLL Design in Locational ICAP Market Design

Q: HOW DOES NEW ENGLAND'S LOCATIONAL ICAP APPROACH COMPARE TO THE CLASSIC VOLL APPROACH?

A: This has been a key question in the Locational ICAP development process and deserves a thorough answer, which will require a more complete description of the Classic VOLL Design, its virtues and its deficiencies.

Before beginning that task, a summary answer can be given.

Similarities:

1. Both require one key administrative input.
2. Both induce the reliable level of investment.
3. Both induce the right mix of investment technologies.

Benefits of Locational ICAP:

1. The Locational ICAP design requires a traditional administrative input that engineers have been using for years, while VOLL itself is an extremely ambiguous input with no accepted methodology for calculation.
2. The Locational ICAP market causes less market risk and thereby lowers the cost of capacity by reducing the rate of return required by investors.
3. The Locational ICAP market inhibits rather than exacerbates market power.

Q: WHY DID YOU CALL THE COMPARISON OF LOCATIONAL ICAP WITH VOLL A KEY QUESTION?

A: To assure that a market design will meet its objectives, both the objectives and the theory underlying the market design must be sound and well understood. The theory of the Classic VOLL Design is relatively well understood and consequently has been used as a starting point or basis for much of the Locational ICAP market design.

Q: WHAT ARE THE OBJECTIVES OF THE ISO DESIGN?

A: The central goal of the ISO market design is a capacity market that, in conjunction with the energy and ancillary service markets, will send the proper price signals to attract and sustain the resources needed for a reliable electric system while costing consumers no more than necessary.

My previous comparison of Classic VOLL and Locational ICAP designs indicates four other subsidiary design objectives:

1. To induce the efficient mix of flexible and inflexible generation.
2. To reduce market risk and thereby reduce the cost of capacity.

3. To minimize market power.
4. To avoid the need for new and uncertain administrative inputs.

These goals and objectives can be summarized by saying that the Locational ICAP design attempts to keep all of the positive features of the Classic VOLL Design while eliminating its negative features.

Q: WOULD YOU PROVIDE A BIT MORE DETAIL ON A CLASSIC VOLL DESIGN?

A: First, it is useful to define VOLL itself. VOLL is the value of lost load or the average value of a MWh of load that is involuntarily shed. Value refers to the dollar value that customers would be willing to pay for the MWh they would have consumed had they been able to pay to avoid interruption. For example, suppose no electric appliances in a certain home are in use except the clocks when there is a half hour interruption of service. Suppose the ten clocks (VCR and oven included) require a total of 10 watts of power. Now suppose the homeowner suffers no inconvenience from having her clocks wrong, other than the inconvenience of having to reset them all, and would have paid, at the very most, $2 to avoid this. In this specific case, the VOLL is $2/0.000005 MWh or, $400,000/MWh. If the home owner had been late for work and missed a meeting, she might have paid $30 to avoid this inconvenience. In that case, her VOLL would have been $6,400,000/MWh. The proper VOLL to use for the market is the weighted average of all such calculations over all consumers of power over all possible load-shedding events.

VOLL is impossible to compute with much accuracy, but in principle the value is well defined, and for purposes of discussion I will assume that, just by chance, we have arrived at exactly the right value. This allows an understanding of the principles involved without concern for the practicalities. These same principles can then be applied to the design of the Locational ICAP market, which does not require impractical calculations.

A Classic VOLL Design sets the energy price to VOLL whenever load has been shed. Assuming we know only the one average VOLL value I have described, and not specific VOLLs for specific load-shedding events, this is the theoretically correct energy price.

Q: WHY DOES THIS GIVE IDEAL RELIABILITY?

A: The Classic VOLL Design does not produce perfect (100%) reliability; instead it produces just the level of reliability for which consumers are willing to pay. To be a bit overly concrete, let me explain it as follows: If VOLL = $15,000/MWh, that means that on average consumers are willing to pay $15,000 to prevent 150,000 100-watt light bulbs from going out for one hour, but they are not willing to pay $15,001 to keep them on. At that price, they would rather be in the dark. The Classic VOLL Design builds more generation as long as each $15,000 worth of generation is keeping at least 150,000 lights on that would otherwise be blacked out for 1 hour per year. But when there is so much generation that spending another $15,000 no longer keeps that many more lights on, the Classic VOLL Design says it is time to stop building generation.

Next, for purposes of exposition, allow me to make four assumptions:

1. There is no exercise of market power in this market
2. Investors are risk neutral
3. Investors have an accurate view of long-run average prices.
4. Startup costs are not significant enough to invalidate marginal-cost pricing.

Given these competitive market assumptions, VOLL pricing as just described, leads to an ideal market outcome[6] which can be described in four parts.

1. The short-run market (dispatch) is efficient.
2. The right level of total investment for reliability will be built.
3. The right mix of technologies will be built.
4. Consumers will pay only the long-run cost of producing power.

With such a market, there would be no need for a Locational ICAP market.

The VOLL price spikes play a crucial role in these outcomes, sending strong signals to generators to make themselves available whenever there is much chance of a load-shedding incident. They also provide the revenue needed to induce sufficient investment to create a reliable level of installed capacity.

The negative aspects of VOLL pricing correspond to violations of the first three of the four assumptions just listed.

[6] The VOLL design replaces actual demand response with the best possible substitute for it. Essentially, the ISO bids in demand as the load would if it could act economically but still faced the restriction of collective load shedding. Four remaining secondary violations of competitive assumptions must still be assumed away: (1) incomplete forward contracting places too much risk on investors, (2) real markets do not have atomistic suppliers and so suffer from market power, (3) investors cannot form rational expectations until they know the relevant probability distributions, and (4) generation costs are non-convex. These smaller flaws are removed by assumption in order to focus on the useful aspects of the VOLL design.

Whenever the market comes near a load-shedding event, there is an enormous incentive for generators to withhold and cause such an event to occur. If they can, they will earn, perhaps, $15,000/MWh on every Megawatt of power not withheld and not covered by a forward contract. Even the need to sell more forward contracts is motivation to exercise market power as high spot prices push up the price of forward contracts. Unfortunately, this type of exercise of market power is extremely inefficient as it must necessarily lead to load-shedding—which is an extremely wasteful thing to do when capacity is physically present.

Because a peaker's fixed cost is roughly $90,000/Megawatt-year, five hours of VOLL prices per year are needed to break even. Because so much fixed cost must be recovered in roughly 5 hours per year, this recovery is highly uncertain. In a hot year with low installed capacity, there could be 20 hours of VOLL, but this would only happen about once every 10 or 15 years. To compensate for such fluctuations, the market will also produce many low cost recovery years. This pattern makes the market risky and investors will demand a risk premium.

Finally, a market with infrequent but large payoffs requires a long observation period before its average behavior can be accurately determined. In the mean time, investors may have very poor information and thus make rather large errors in investment. This can lead to both over and under investment, which increases the risk of unreliability.

In summary, the negative aspects of a VOLL approach are:

1. The VOLL itself is extremely difficult to determine.
2. VOLL pricing increases market power.

3. VOLL pricing increases market risk.
4. VOLL pricing reduces the accuracy of investment and thus increases the risk of unreliability.

Q: WOULD YOU EXPLAIN HOW LOCATIONAL ICAP CAPTURES THE ADVANTAGES OF A VOLL PRICING DESIGN?

A: The details are a bit complicated and it is the purpose of this testimony to elaborate them, but I will summarize.

A Reliable Capacity Level. The Locational ICAP Demand Curve pays the same on average as a VOLL market when installed capacity is at the target level. This induces the same average amount of capacity.

The Reliable and Efficient Technology Mix. Like VOLL, Locational ICAP will be paid to generators who are available during shortages and not to generators who find it impossible or unprofitable to show up when most needed. This will send almost the same investment signals as VOLL pricing with respect to flexibility and the dependability of fuel contracts.

Dispatch. Locational ICAP leaves the dispatch unchanged except for reproducing the strong incentives of VOLL for generators to be available during shortage conditions. This brings the dispatch closer to the VOLL standard than would a standard ICAP approach or an energy-only approach without VOLL pricing.

Q: WOULD YOU EXPLAIN HOW LOCATIONAL ICAP AVOIDS THE DISADVANTAGES OF A VOLL PRICING DESIGN?

A: **Risk reduction.** The ISO’s Locational ICAP actually hedges the risk of shortage prices in the energy market as well as introducing no weather risk of its own. When energy prices are high due to shortages, VOLL would add to them while Locational ICAP subtracts them from the Locational ICAP Demand Curve. Thus, fixed-cost recovery no longer fluctuates with irrelevant factors such as weather and outages.

Predictability. A second key to risk reduction and to damping the investment cycle is predictability of fixed-cost recovery. Locational ICAP is predictable because it is transparent. With VOLL pricing, not only are annual fluctuations due to weather unknowable in advance, but average fixed-cost recovery can only be crudely approximated with complex calculations using load and outage probability distributions. Locational ICAP allows actual and average values (which are the same) to be read off the demand curve. Locational ICAP is extremely transparent when compared with almost any other design.

Market power reduction. When there is a near shortage in a VOLL market, suppliers are motivated to turn it into an actual shortage. Under the ISO's Locational ICAP, energy-price shortage revenues are netted out and the motive to cause shortages is nearly eliminated. (Shortage prices retain their full incentive effect; it is only the incentive to manipulate those prices that is removed by Locational ICAP.)

Eliminate calculation of VOLL. The administrative setting of VOLL, with all its attendant difficulties, is replaced by the standard procedure of computing the system's reliable level of installed capacity.

Q: ARE THERE SPECIFIC DESIGN FEATURES OF THE LOCATIONAL ICAP MARKET THAT WERE BASED ON THE CLASSIC VOLL DESIGN?

A: Yes, a few. The reduction in Locational ICAP payments for unavailability was developed to mimic the payment of VOLL prices.

The VOLL revenue curve flattens out at higher capacity values, so the Locational ICAP Demand Curve was given this same property.

The VOLL market provides locational investment incentives, so Locational ICAP was designed to do the same. Locational energy price differences are correctly computed using Locational Marginal Pricing ("LMP"). Locational ICAP Payments are simply a substitute for the missing VOLL energy prices, which are energy prices. Because Locational ICAP Prices are substitutes for energy prices, and because they are locational ~~energy~~ prices, they should follow the same rules as LMP prices. For example, if a line between two Locational ICAP regions is not congested, the two regional Locational ICAP Prices should be equal, just as two energy prices should be equal.

Q: ISN'T VOLL PRICING QUALITATIVELY DIFFERENT FROM LOCATIONAL ICAP PRICING? ONE INCLUDES ALL REVENUES, THE OTHER A SMALL FRACTION OF REVENUES.

A: That is correct. Nonetheless, the crucial part of VOLL revenues is completely comparable to Locational ICAP revenue. To make this clear we must consider a Benchmark Generator.

The ”Benchmark Generator” is one that the market will build, not an out-of-date or impractical one, and for accuracy of inframarginal rent calculations, it is defined as the efficient generator with the highest marginal cost. It will be discussed in detail later.

”Average Peak VOLL Energy Rent” (PVR) is the energy revenue that would be earned by the Benchmark Generator above its variable costs under the Classic VOLL Design in an average year with the given level of installed capacity.

PVR is exactly analogous to the Locational ICAP Price that is determined by the Locational ICAP Demand Curve.

Q: COULD YOU EXPAND ON THE LOCATIONAL ICAP MARKET DEMAND CURVE’S RELATIONSHIP TO VOLL?

A: Because VOLL’s hourly prices can be so extreme they are often the focus of discussions of VOLL pricing, but it is more informative to focus on annual rents, PVR.

As shown in the figure below, PVR will be high on average when there is too little installed capacity and low on average when there is too much.

Notice the qualifier “on average.” Actual Peak Energy-Market Rents can deviate substantially from this average because of weather and unexpected generation outages.

The Locational ICAP Demand Curve is designed to replace PVR. If the capacity level averages out at the Target Capacity Level, both PVR and the Locational ICAP Price should average out to be BCC. As with VOLL, it increases as installed capacity falls and declines as installed capacity increases.

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Q: WHAT ARE THE MAIN DIFFERENCES BETWEEN THE TWO ANNUAL REVENUE CURVES?

A: The first difference between the Peak VOLL Rent (PVR) curve and the Locational ICAP Demand Curve is its shape. The PVR curve becomes extremely steep as capacity dwindles and becomes very flat as it increases, as can be seen in the Figure above. The Locational ICAP Demand Curve is moderately steep at almost all relevant levels although it becomes extremely flat for very low and very high levels of capacity.

The second difference is that the PVR curve only tells what revenue to *expect* in a given year whereas the Locational ICAP Demand Curve gives a precise value for the year. Depending on weather and forced outages, the actual VOLL revenue may be very different from the average rent of PVR. This difference can be significant. Locational ICAP eliminates the uncertainty of weather and most of the uncertainty due to forced outages.

Q: DOESN'T THE VOLL DEMAND CURVE EXPRESS THE VALUE OF THE PRODUCT DEMANDED AND SHOULDN'T THE LICAP DEMAND CURVE DO THE SAME?

A: This is actually the same question asked by the Commission—"Should the height and slope of the curve be based on the cost of new entry or on other factors, such as an estimate of the reliability value to loads of alternative levels of capacity, and if the latter, what are reasonable estimates of such reliability values?" The choice is between a cost (of new entry) approach or a value (of lost load) approach. After describing the Classic VOLL Design in more depth, a few points can be added.

First, the annual average VOLL energy-market rent curve shown in the figure above, is the Locational ICAP Demand Curve that would result from adopting the value approach—using "an estimate of the reliability value to loads of alternative levels of capacity." As noted previously, this is almost impossible to estimate in practice, but we can be quite sure that it would be extremely steep when it crossed the long-run supply curve at BCC. As noted previously, this steepness would make it quite risky for investors. A tiny change in capacity would cause a large change in revenue. This was exactly the problem with the previous ICAP demand function—it was vertical. At the ICAP knife-edge, a one Megawatt change of capacity would cause an enormous change in revenues.

These observations produce a bit of a paradox. It is always desirable to have a demand curve reflect value, but in this case the demand curve would be so steep that it would introduce a large amount of market risk. What should be done? Even if it were possible to compute a VOLL-based demand curve, it would provide little advantage and much disadvantage. As noted the market risk is the disadvantage, but what is the advantage?

The advantage of a demand curve based on value is that when the price of the good (generating capacity) being demanded changes, the demand for that good can change accordingly. If the price of strawberries falls from $1 per basket to 50¢, we buy more. In present circumstances, when the cost of a frame gas turbine unit drops by 2% next year the demand curve could tell us to buy one more gas turbine—if we could draw it that accurately. But we cannot and if even if we could, the engineers have been telling us for years that they do not think it would make much difference at all in how many we should buy. In theory, a value-based demand curve is good, but in practice we cannot do it and if we could it would help too little to notice. All it would do is impose a lot of costly risk on investors.

Q: WHAT ARE THE DEMAND-CURVE'S MAIN PURPOSES?

A: Both the Locational ICAP Demand Curve and the PVR curve play four key roles:

1. Determination of the long-run average installed capacity level and thus reliability
2. Determination of expected annual fixed cost-recovery
3. Determination of market risk
4. Partial determination of market power

3. Basic Theory of the Locational ICAP Demand Curve

Q: HOW DOES THE LOCATIONAL ICAP DEMAND CURVE RELATE TO LOCATIONAL ICAP PRICE AND PAYMENTS?

A: Under VOLL pricing, the PVR curve covers all fixed cost recovery of the Benchmark Generator. The Locational ICAP Demand Curve also covers this same fixed-cost recovery, but the cost recovery comes from two sources: the energy market and the Locational ICAP market. In other words, the Locational ICAP Demand Curve describes the sum of Peak Energy-Market Rents and Locational ICAP revenues.

Note that the "Peak Energy-Market Rents" ("PER") are the actual net revenues of the Benchmark Generator for the year in question and are not Peak VOLL Rents (PVR) the theoretical concept previously defined.

The "Locational ICAP Payment," ("LP") is the Locational ICAP demand-curve value less the appropriate Peak Energy-Market Rents (except under certain extreme conditions discussed later).

The "Locational ICAP Price," ("P"), as distinct from the Locational ICAP Payment, is the value determined from the Locational ICAP Demand Curve and so includes both Locational ICAP and Peak Energy-Market Rents, PER.

Q: IN GENERAL TERMS, HOW WILL THE PROPOSED LICAP MARKET WORK?

A: A demand curve that relates price to quantity will be established and approved by the Commission.

Each month, participants will bid their capacity into the market.

Load will purchase the amount of capacity needed to meet their obligation for that month.

In this way, load will pay an amount determined by the Locational ICAP Demand Curve and generation will be paid that amount. We expect almost all generation to participate and all load must participate.

Q: WHAT ARE THE PARAMETERS OF THE DEMAND CURVE?

A: The demand curve has four regions, with the two middle regions by far the most important. In these two regions the curve slopes down and changes slope at a capacity level designated by C_K. At that point, the demand curve takes the value

EBCC, which is the ~~EBCC~~**Expected BCC**. This point is referred to as the kink in the demand curve.

The Benchmark Cost of Capacity ("BCC") is the average fixed-cost recovery that must be paid to an investor over the life of a plant to make the investor just indifferent to investing.

The Estimated Benchmark Cost of Capacity ("EBCC") is the ISO's best estimate of BCC. It takes into account all known costs required to build a Benchmark Generator and keep it operable.

To the left of the kink the demand curve slopes up steeply until it reaches a level of 2×EBCC at capacity level OC.

To the right of the kink, the demand curve slopes down with 1/3 of the slope it has to the left of C_K until it reaches zero at capacity C_{Max}.

For capacities below OC, the demand curve is flat at a value of 2×EBCC, and above C_{Max} it is flat at a value of zero.

Because of the kink, the long-run equilibrium value of capacity will be slightly above C_K. C_K is chosen so that a normal distribution of installed capacities with mean C_{Target} and standard deviation SD determines an average Locational ICAP Price of EBCC.

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Q: WHAT ARE THE PROPERTIES OF THE SHORT-RUN (ANNUAL) LOCATIONAL ICAP PRICE?

A: Although the supply side of the market will bid, the opportunity cost to an operable generator of providing Locational ICAP is usually close to zero. If the market is competitive, the offer price will be close to zero so the Short-Run Locational ICAP Price will be determined essentially by the demand curve and the amount of installed capacity.

The short-run price needs to be high enough to compensate for any costs of offering in the spot market (which is an obligation of Locational ICAP sellers). It must also compensate for any opportunities of net savings from deactivating a generator for a period of time. (Because of energy revenues, few generators find deactivation to be a net savings.) For high levels of surplus capacity, supplier offers will ensure the Locational ICAP Payments are high enough for these purposes.

Even accounting for these opportunity costs, the cost to an operable generator of providing Locational ICAP is usually close to zero. If the market is competitive, the offer prices will be quite low. Accordingly, except when there is a large amount of over-capacity, the Short-Run Locational ICAP Price will be determined by the demand function and the amount of installed capacity.

When there is enough excess capacity to drive the Locational ICAP Price to zero, the Locational ICAP Price will be determined by the opportunity costs of the marginal bidder, and this should be a low value compared with BCC~~,~~.

In effect, the short-run capacity supply curve is vertical at the installed-capacity level, so <u>in the short-run the supply side determines quantity and the demand side determines price</u>. Thus, the Short-Run Locational ICAP Price is essentially determined administratively.

When there is excess capacity and the vertical part of the supply curve does not intersect the demand curve, then the supply curve will determine price, but only within a narrow and low range of values.

Q: WHAT ARE THE BENEFICIAL SHORT-RUN INCENTIVES OF THE LOCATIONAL ICAP MARKET PROPOSED BY THE ISO?

A: There are three short-run incentives and they complement Locational ICAP's main purposes, which are to assure the proper level of capacity in the long run and reduce market risk. These are

1. To induce availability under high load conditions.
2. To induce participation in the energy spot market.
3. To suppress market power in the energy spot market.

There are two parts to incentive #1. First, high short-run payments induce generators to sell Locational ICAP to the ISO even though there may be opportunities to export energy and even capacity. Second, high short-run prices induce those who have sold Locational ICAP to make a special effort to be available during Critical Hours because Locational ICAP Payments are adjusted for availability during those hours.

Participation in the spot market is very useful and the Locational ICAP market provides a good means of inducing it. Otherwise there is no special connection between the two.

The least crucial incentive, but still a valuable one, is the suppression of market power in the spot market. This is a useful side effect of the present design.

Finally, it is important to note that the central purpose of these annual (Short-Run) Locational ICAP Prices is not a short-run purpose, but a long-run purpose.

Q: HOW DO YOU DEFINE THE LONG-RUN INSTALLED-CAPACITY LEVEL?

A: Because capacity is always increasing, the long-run capacity level is best defined as a percentage of the minimum reliable capacity level, OC.

If there is a Target Capacity Level, C_{Target} that is 5.4% higher, and we hit that target on average over the long run, then the long-run capacity level is 105.4% of OC. This Target Capacity Level was selected because it is the historical average level of capacity relative to Objective Capability. If the distribution of installed capacity levels maintains its historical standard deviation, the Target Capacity Level will ensure that actual installed capacity falls below OC in only about 15% of the years. This is important, because history also teaches that there is likely to be market intervention when installed capacity falls below this level. Historically, although OC was described as the "Objective," it was clearly treated as a minimum acceptable level. When designing the market this ambiguity has been resolved in favor of realism rather than past rhetoric.

It may be better to think of long-run capacity level as the long-run average percent of OC that would be found if the Locational ICAP curve were maintained in its current position over the long run.

The Locational ICAP Demand Curve was designed to cause the long-run capacity level to equal the Target Capacity Level.

Q: WHAT DETERMINES THE LONG-RUN CAPACITY?

A: The Locational ICAP Demand Curve is the main determinant of the long-run average installed capacity level. The demand curve offers to pay more than the EBCC whenever C is less than C_K and less whenever C is greater than C_K. So when C is less than C_K, investors tend to build more and when C is more than C_K they tend to stop building and let C decline relative to load.

This keeps C in the vicinity of C_K. Because the demand curve is steeper on the left, short-run profits increase faster when capacity is less than C_K than they decrease when capacity is greater than C_K. If the distribution of actual capacities (C's) were symmetrical around C_K, short-run profits would average a bit more than EBCC. This upward profit bias at a mean value of C_K pushes the distribution of C's up a little and so the average long-run capacity level (assuming a symmetrical distribution) will be just a little more than C_K. Given the historically observed variance in C, I have estimated that the average C will be about 1.6% higher than C_K.

If there were no randomness in C, the intersection of the supply and demand curves would be the exact determinant of long-run C.

Q: HOW SERIOUS ARE ERRORS IN INDUCED CAPACITY?

A: That depends on the direction of the error and the size of the error. For small errors, of say 3%, there is almost no effect on total cost to load. Suppose the ideal installed capacity level is 30 GW and, the market builds 31 GW of capacity. The extra capacity has a cost, though it will be the cheapest type of capacity and since it almost never runs there will be essentially no fuel cost. Thus its impact on the total cost of production will be less than 1% and on retail costs even less. But for small errors there is another more important mitigating effect.

The ideal level of installed capacity is the point at which the cost of more capacity exactly balances the benefit of reduced outages. In other words, at the ideal level, the costs of an increase in capacity are exactly canceled out by the benefits. For a very small change like 3%, the benefits do not quite cancel out all of the costs, but they cancel most of them. Consequently, small errors have almost no net cost to consumers.

However, errors on the low side of the ideal capacity level soon run into rapidly increasing costs of outages which overwhelm the benefits of cost savings from less installed capacity.

These effects have been understood by engineers for a long time and are part of the reason they tend to err on the high side with installed capacity. They have been recently computed for PJM[7] and this computation shows that, relative to the optimal capacity level, a 6% decrease in capacity would cause a 5% increase in total wholesale cost. It would require a 20% increase in capacity to increase total wholesale costs by 5%. Total wholesale costs, in this calculation, include the cost of shed load figured at a VOLL of $24,000/MWh. The 5% increase in wholesale costs is equivalent to approximately a 2% increase in retail costs. Consequently, if one were to target the center of this 26% range, a 13% error in either direction would cause only a 2% increase in cost to consumers.

The PJM calculation is not exact, and would not apply exactly to the ISO, but two qualitative conclusions are warranted. The cost of erring on the lower side when building capacity is greater than the cost of erring on the high side. Near the optimal level of capacity, small errors in the capacity level have very little percentage impact on total cost to consumers.

Q: WHAT ARE THE LONG-RUN PURPOSES OF LOCATIONAL ICAP?

A: There are three long-run purposes:

1. Inducement of the correct level of investment.
2. Reduction of market risk.
3. Inducement of the right mix of technologies.

The first purpose is the central purpose of Locational ICAP and was discussed in the introduction. The correct levels of investment and installed capacity are achieved by making the Locational ICAP Demand Curve intersect BCC near the desired capacity level.

[7] Seethe public PJM document, “Normalized Total System Costs vs. Reserve Margin” by Javier Inon and Benjamin F. Hobbs, The Johns Hopkins University, August, 2004.

The second purpose, risk reduction, is achieved by stabilizing the year-to-year fluctuations in the Short-Run Locational ICAP Price.

The market induces the right mix of technology by giving different technologies different inframarginal rents. Locational ICAP does not interfere with this. The Classic VOLL Design augments this signal with one which rewards flexible generation that can reliably be present during shortages. By mimicking this, Locational ICAP induces nearly the same efficient mix as does the Classic VOLL Design.

4. The Market Controls the Long-Run Locational ICAP Price

Q: IN THE SHORT-RUN, DOES THE LOCATIONAL ICAP DEMAND CURVE DETERMINE PRICE OR QUANTITY?

The quantity of installed capacity is fixed, so the short-run supply function is usually vertical at its intersection with the Locational ICAP Demand Curve, and this determines the Short-Run Locational ICAP Price.

When the Locational ICAP Demand Curve has determined that price will be low, supply curve elasticity will play a role in determining just how low it is. Thus, the role of supply in short-run price determination is small and the demand curve is by far the primary controller of price. Consequently, the short answer to the question is: “In the short-run, the demand curve controls price and not quantity.”

Q: IN THE LONG-RUN, DOES THE LOCATIONAL ICAP DEMAND CURVE DETERMINE PRICE OR QUANTITY?

A: This time, the short answer is just the reverse: "In the long run, the Locational ICAP demand function determines quantity and not price."

The quantity of installed capacity is extremely elastic in the long term, so the long-run supply function is horizontal, and the Locational ICAP Demand Curve determines the quantity of capacity installed, which is where the long run supply curve or BCC intersects the demand curve. Because the long-run supply curve is horizontal in the relevant region, the long-run price is determined by the level of that curve.

Put another way, the market for new generation investment is competitive, and in a competitive market, the price is driven down to the cost of production, in this case the Long-Run Locational ICAP Price will be the BCC.

Because this is by far the most frequent source of confusion in discussions of ICAP markets, this point bears repeating.

The market determines the Long-Run Locational ICAP Price, and so it is not determined by the estimate of the BCC made by the market administrators and federal regulators.

Q: HOW DO YOU DEFINE THE LONG-RUN LOCATIONAL ICAP PRICE?

A: In economics, the term long-run price is typically used to mean the long-run equilibrium price. Although the market may never achieve this price exactly, on average the short-run prices will be quite close to the long-run equilibrium price. A related concept is the expectation of entrepreneurs regarding the long-run average of the short-run prices. This is the value that will determine the success or failure of their investment. But, consumers are more interested in how much they will actually have to pay. Fortunately the three concepts are nearly coincident, and for convenience I will use "long-run price" to mean this coincidence of prices when the distinctions are of no consequence.

However, to discuss the main point concerning long-run prices, I will need to be quite precise and so I will define the expected and average short-run price concepts in more detail.

I define the "Long-Run Locational ICAP Price", ("P_{LR}") to be the equilibrium price of a market in which the capacity level has plenty of time to adjust in response to the Locational ICAP Demand Curve.

I define the "actual average price" ("AAP") to be the long-run average of the actual (realized) short-run prices.[8]

I define the "expected average price" (EAP) to be the long-run average price expected by investors.[9] EAP is the investors' expected value of AAP.

Q: WHAT IS THE "MAIN POINT" ABOUT LONG-RUN LOCATIONAL ICAP PRICES THAT REQUIRES THESE DEFINITIONS?

A: It is simply a more carefully stated version of the point I made earlier, that the Long-Run Locational ICAP Price equals BCC. It is this:

The best available estimate of the Locational ICAP market's outcome is that AAP = BCC.

[8] To be more precise, the long-run average should be defined as taking place over the life of the relevant investment and using weights that decline exponentially at the investors' discount rate.

Q: WHAT ASSUMPTIONS UNDERLIE THIS POINT?

A: At least three principle assumptions are required to come to this conclusion:

Assumption 1: The market for new investment is competitive.

Assumption 2: Locational ICAP is high enough that Locational ICAP Payments are almost always non-zero.

Assumption 3: Investors are not systematically mistaken about their expectations of AAP in a way that can be publicly verified.

Q: WHAT WOULD HAPPEN IF THESE ASSUMPTIONS WERE NOT MET?

A: **Consider assumption 1.** To take an extreme case, if there were only a single provider of new generation, the monopolist would only build when revenues were much higher than BCC.

Note that in this case, P_{LR} > BCC, would not be caused by any error in the construction of the demand curve. For example, it would not be caused by the demand curve being too high. The cause is simply the market power of the investor.

Consider assumption 2. This assumption rules out the trivial case of setting the Locational ICAP curve so low that it is dominated by energy market rents and no longer determines short-run profits.

If this assumption is violated, the conclusion that long-run P = BCC, is simply replaced by a more complicated looking one that has the same qualitative meaning: the long-run average of max(P, PER) = BCC. This just means that investors will be paid the right amount on average, but that average will include

[9] To be more precise, the long-run average should be qualified as above and the investor should be specified

some years when they are paid PER because its higher than the Locational ICAP Price.

Consider assumption 3. Suppose investors always underestimated AAP by 50%, so that if the average short run price were $7/kW-month they would expect it to be $3.50 and EAP would be $3.50. Because of this systematic error, if BCC were $7/kW-month investors would not invest until AAP reached $14/kW-month.

By refusing to invest until AAP reached such a high value, they would force installed capacity down until Short-Run Locational ICAP Prices actually did rise to $14 and then hovered around that value, causing AAP to reach this value.

Q: ARE THESE THE ONLY REASONS P_{LR} CAN DEVIATE FROM BCC?

A: Except for random deviations which are impossible to anticipate, I believe they are. They are the only systematic causes for a deviation. But there is one more reason that may appear to cause a deviation.

A seeming exception to the long-run pricing rule can be caused by extremely rapid growth in the demand for installed capacity. If the Locational ICAP Demand Curve were shifted right to higher capacity levels at say 20% per year, the market would find it hard to keep up with this rate and scarcity pricing for gas turbines would result. This would increase the BCC.

This is not an exception even though it will increase the long-run price paid to maintain our target level of capacity. The price, P_{LR}, will increase because BCC increases, but it will still equal BCC.

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to be the marginal investor.

Q: SO, IS THERE ANY WAY THE SHAPE OF THE DEMAND CURVE CAN AFFECT THE LONG-RUN LOCATIONAL ICAP PRICE?

A: Assumption 2 indicated that if the curve is set so low that it cannot provide BCC until capacity falls and the energy market takes over, then the Locational ICAP Price will average too little. This deficiency will be exactly made up by the energy market. This is the only way in which selecting the wrong demand curve can cause a deviation for P_{LR} from BCC. It is important to note that this result does not say P_{LR} = EBCC.

Monopolistic investors can raise P_{LR} above BCC, but that is not a problem with the demand curve.

A rapidly increasing demand curve can increase BCC, but P_{LR} will still equal BCC.

Making the demand curve too steep might increase risk and the risk premium might increase BCC, but again, P_{LR} will still equal BCC.

Setting the Locational ICAP Demand Curve a little too high or a little too far right will increase the level of installed capacity and setting it too low or too far left will cause the reverse, but none of these will cause P_{LR} to deviate from BCC.

Q: HOW DOES THE SHORT-RUN PRICE ADJUST TO PRODUCE THE LONG-RUN AVERAGE PRICE?

A: When the short run price is higher than BCC it stimulates investment. This increases capacity and this reduces the Locational ICAP Price. The increase in capacity discourages investment, which slows capacity growth relative to load growth. When installed capacity becomes low enough, this causes the

Locational ICAP Price to increase. Thus, when P_{LR} is above BCC, investment causes it to decrease and when it is below BCC, investment slows or stops and causes it to increase. Thus, the short-run price will oscillate around BCC.

These oscillations are damped by the foresight of investors, especially if the Locational ICAP mechanism is transparent. Although the short-run price will oscillate above and below, the process is a bit more complex than just described. Investors anticipate changes in Locational ICAP Price and try to make sure they show up at the beginning of a Locational ICAP high-price period. This tends to diminish the size of these high-price periods. The investment sequence works more like this.

Investment is not stimulated by current short-run prices, but by the anticipation of high future short-run prices. Because of this, investors do not necessarily wait for a high Locational ICAP Price before they begin investing. They pay attention to other investments and to load growth and if they believe that target capacity will surpass installed capacity next year and if they see no other investment underway, they will conclude that high Locational ICAP Prices might begin and persist long enough for them to profit from them. Then they will invest.

Q: IS THIS RESULT CONCERNING LONG-RUN PRICE UNUSUAL IN ECONOMICS?

A: Actually it is a standard result. Investment in generation is much like investment in other industries and is also similar to the provision of any normal good. Ignoring economies of scale, and assuming the investment industry is competitive, leads to the conclusion that the long-run price equals the long-run cost of providing the good or the investment. Because the long-run competitive supply curve is flat and equal in height to the long-run cost of supply, the position and shape of the demand curve plays no role in the determination of the long-run price.

Even if the long-run supply curve slopes up due to some factor of production being limited, or slopes down due to economies of scale, a competitive market will set the long-run price equal to the long-run cost of supply corresponding to the amount actually supplied. Demand can increase or decrease the amount supplied (New England can buy more or less reliability), but given a quantity supplied, demand has no affect on price.

The result that long-run price equals long-run cost of supply depends only on the supply side of the market being competitive. The details of how this price comes about are the description of how competition forces price down to the competitive level, which is the long-run cost. This mechanism is essentially that same in every market with a competitive supply side and is not unique to the Locational ICAP market.

Q: IS THE MAIN DRIVER BEHIND THIS RESULT YOUR FIRST ASSUMPTION, THAT THE MARKET FOR NEW GENERATION IS COMPETITIVE?

A: That is correct. Competition is the main force behind this result. It provides the impetuous for the entire adjustment process described above and below. Competition holds long-run prices down to long-run cost, makes the long-run cost curve flat, and assures that the required generation will be built expeditiously. It is the reason markets work, when they do work.

Fortunately, because the relevant market is the market for new investment, there is, by definition, time for entry. Because there is time to build, there are many potential suppliers and no one supplier can keep the others out. Consequently it is almost certain that competitive forces will be strong in this market.

Q: CAN YOU NOW PRESENT A DETAILED ARGUMENT FOR YOUR "MAIN POINT," THAT AAP = BCC?

A: Yes, but first I must define BCC more carefully. BCC is the Locational ICAP Price level that would, if generators knew with certainty it would persist, induce them to build the target level of capacity, no more and no less.[10] Thus BCC, although determined by real world costs, is ultimately defined as the costs that must be covered to make investors willing to build the needed capacity.

Step 1. Assume that the Locational ICAP Demand Curve is high enough to exceed PER in every year. I have previously discussed why this assumption does not affect the essence of the result. It should also be nearly true.

Step 2. This step uses the assumption that the supply side of the market is competitive to argue that EAP = BCC.

This conclusion is based on the fact that any other assumption is contradicted by the forces of competition.

[10] This definition does not account for risk because that would make the following argument too complex. Instead we will simply note that risk raises the BCC and that investors will surely take this into account just as they take all other costs into account. Thus, risk will increase both BCC and AAP by the same amount, just as any other cost would.

If EAP > BCC, this means investors expect the average Short-Run Locational ICAP Price to pay more than is required to induce them to build more generation. In this case, because there is competition and so withholding supply cannot keep the price up, some investor will build more generation. This will lower the Short-Run Locational ICAP Price starting when this generation enters service. Investors will be aware of this reduction in AAP and they will lower their expectation of the average short-run price EAP. Thus, as long as EAP > BCC, investment will increase and continue to reduce EAP.

If EAP < BCC, investors will stop investing. This will raise AAP. They will understand this and raise their estimate, EAP, until it equals BCC.

Step 3. This step uses the assumption that investors are not obviously biased to argue that EAP is the best available estimate of AAP.

This conclusion is based on the fact that misestimating the future short-run prices will cause investors to make costly mistakes. If they over estimate AAP, they will invest when AAP is too low to cover their costs and they will lose money on their investment. If they underestimate AAP, they will miss valuable investment opportunities.

Correctly estimating AAP is far more important to investors than to any other market participants including the market designers, administrators and regulators. If anyone else could estimate AAP more accurately, investors would purchase that estimate. Consequently, we must expect them to have the best available estimate.

Step 4. From step 3, "EAP is the best available estimate of AAP." From step 2, EAP = BCC. Combining these gives our result: The best available estimate of AAP is BCC.

Q: THIS STILL SOUNDS A BIT ABSTRACT. CAN YOU RELATE IT TO CONSUMER COSTS?

A: It speaks directly to actual consumer cost, but is somewhat abstractly related to the theoretical concept of the "Long-Run Locational ICAP Price."

The Actual Average Price, AAP, is not exactly the theoretical long-run price, but it will be close to it. However, AAP is what matters because that is what consumers will actually pay on average. The result says that the best estimate of what consumers will pay on average, due to the proposed Locational ICAP design, is the true fixed cost of BCC.

The conclusion that AAP = BCC (and so long-run P = BCC) allows a comparison of the total revenues of a Benchmark Generator selling capacity into the Locational ICAP market with its total long-run costs.

1. Total Revenue = LP + Energy Revenues

2. LP = P – PER

3. PER = Energy Revenues – Variable Costs

Abbreviating Energy Revenue by ER and Variable cost by VC we have:

4. Total Revenue = P – (ER – VC) + ER.

This simplifies to

5. Total Revenue = P + VC

But the Long-Run Locational ICAP Price, P, equals BCC, so

6. Long-run Average Total Revenue = BCC + VC

But BCC is just the long-run annualized fixed cost of the Benchmark Generator, and fixed costs plus variable costs are total costs, so

7. Long-run Average Total Revenue = Long-Run Average Total Cost

The competitive market result, which I have just applied to the Locational ICAP market to show that the Locational ICAP Price will equal BCC, also proves that the Benchmark Generator will be paid enough to cover its total cost of production and no more. Of course this assumes a competitive market.

When the Benchmark Generator earns just enough to cover its total long-run costs, competition will ensure that other generators do also. They will be brought into equilibrium with the Benchmark Generator. If others earn less than total costs, no one will build generation. If other generators earn more they will be favored by the market until there are too many of them and their revenues decline to the point where they are just sufficient to cover their total costs.

This partly explains why the cost paid by consumers under the Locational ICAP design for generating capacity will be just and reasonable. The Locational ICAP design establishes a market where the cost of Locational ICAP plus the energy market revenues will be just sufficient to cover the total cost of producing power. This does not prove that the right amount of capacity will be purchased, but consumers will not overpay for what is purchased, they will pay a long-run competitive price because of market forces.

Q: ARE YOU REALLY SURE THE LONG-RUN PRICE WILL EQUAL BCC?

A: Although economics is unequivocal on this point, it often fails to convince the non-specialist. For this reason, it makes sense to take a closer look as some arguments that purport to show that the Locational ICAP Price could be too high or too low.

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Q: HOW CAN YOU BE SURE A TOO-HIGH DEMAND CURVE WILL NOT PAY GENERATORS TOO MUCH?

A: Suppose a little extra demand did cause permanently higher-than-normal profits. Suppliers would figure this out. When suppliers believe that profits will be permanently above normal, they flood the market with supply. But we have also seen that this depresses profits. Thus, competitive entry makes any supposition of higher long-run average profits self-contradictory.

Q: ARE YOU SAYING THAT A HIGHER DEMAND CURVE THAT PAYS MORE AT EVERY LEVEL OF CAPACITY WILL NOT PAY GENERATORS MORE?

A: It will pay generators more initially, but not after that. If the market is 4% short of capacity under the low demand curve and 6% short of capacity under the high demand curve, then prices will be high during the time the market does its first 2% of catching up. After that it is only 4% short and it pays the same amount per unit of capacity as it would pay at the start under the lower demand curve. From then on prices match up under the two scenarios.

If the demand curve is set to buy too much reliability/capacity, profits will be a little too high initially because the market will at first appear to be in greater jeopardy than it really is. The problem is not that the demand curve is set to pay too much—it has no control over long-term profits; the problem is that the demand curve is set to buy too much reliability.

Q: CAN LOCATIONAL ICAP HAVE AN EFFECT ON THE LONG-RUN COST TO CONSUMERS?

A: Yes. Because the design lowers risk and thus BCC, it will reduce the long-run cost to consumers. An error in Locational ICAP can also cause too much or too little capacity to be purchased. If the target capacity is the optimal level of capacity, then any deviation from this level will increase consumer costs. If more capacity is purchased, the extra cost of capacity will exceed the cost reduction from increased reliability. If less capacity is purchased, decreased reliability will impose more cost that the savings from reduced capacity. For small mistakes, as I have already discussed, this effect is second order and thus very small.

Q: WHAT CONCLUSION DO YOU DRAW ABOUT THE DESIGN OF THE LOCATIONALICAPDEMANDFUNCTIONFROMTHESE CONSIDERATIONS OF MARKET DYNAMICS AND SENSITIVITIES?

A: The crucial considerations are as follows:

1. The market will assure the right Long-Run Locational ICAP Price.
2. The Locational ICAP Demand Curve will control the level of installed capacity.

3. There is several percent of leeway in the efficient level of installed capacity, especially on the high-capacity side.

These considerations are reassuring. First, if the right amount of capacity is targeted, then consumers will pay the right price for the right quantity. The main problem is simply to induce the right level of capacity. The investment market, assuming it is competitive, will set the right price.

Second, the most crucial specification of the Locational ICAP design is that the intersection of the Locational ICAP Demand Curve and the long-run supply curve (horizontal at BCC) should occur near C_{Target}.

Third, there is a reasonable amount of leeway in positioning this intersection and it is better to err on the high side.

5. Adjusting the Locational ICAP Demand Curve to Induce the Right Amount of Installed Capacity

Q: BECAUSE THE MARKET CONTROLS THE LONG RUN PRICE, WHAT IS THE MOST IMPORTANT DESIGN GOAL OF THE DEMAND CURVE?

A: Many would answer that making sure it is neither too high nor two low is most important, but that is the wrong way to think about the problem. It is better to understand that shifting it up really amounts to shifting it right, and shifting it down amounts to shifting it left, and it is the left-right position that matters. This is best illustrated with a diagram.

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The diagram shows that the only effect of shifting the demand curve up is to shift the equilibrium to the right. This is a simplified, completely linear demand curve, but this result still holds in essence for the proposed demand curve. As argued previously, the market determines that the Long-Run Locational ICAP Price will be BCC, so all the demand curve determines is the average capacity level, and the more-subtle properties of price and quantity fluctuations.

The most important aspect of the demand curve is that it be positioned the correct distance to the right so that it goes near the point determined by C_{Target} and BCC. Because of random capacity fluctuations, it is desirable to have it pass about 1% or 2% left of this point. Getting the left-right position of the demand curve right will induce the desired level of capacity for reliability, and this is the central goal of Locational ICAP.

Q: IS THE EQUALIBRIUM CAPACITY COMPLETELY DETERMINED BY THE HORIZONTAL POSITION OF THE DEMAND CURVE?

A: No. BCC plays a crucial role and it is not known precisely. This causes some error in positioning equilibrium capacity, and the size of that error is affected not just by the estimation error in BCC, but also by the slope of the demand curve.

Suppose the ISO had chosen an extremely flat slope to minimize risk, say a slope of $1/kW-month for each 10% change in capacity. If the estimate of BCC were $1.00 per month too high (*i.e.* EBCC exceeds BCC by $1.00/kW-month), then the long-run equilibrium capacity would be 15% higher than anticipated. This is shown in the diagram below.

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As shown in the diagram, accidentally estimating BCC high by $1.00 causes the Locational ICAP Demand Curve to be set high by $1.00 which causes the equilibrium value of installed capacity to be high by 15% which would provide too much reliability at too great a cost.

More disturbing to contemplate is the error of underestimating BCC by $1.00. This would cause the equilibrium capacity level to fall 15% below the target level, which would provide vastly too little reliability. As I discussed earlier, the cost to load of such an underestimate would be far greater than the cost of the symmetrical overestimate.

The cost of errors due to misestimates of BCC can be minimized by using a steep demand curve. Because downside errors are far more costly than upside errors, the most sensible design uses a steeper demand curve on the downside than on the upside, as is shown in the diagram below. In this figure, the level of installed capacity is shown exactly at the intersection of the demand curve with the true Benchmark Cost of Capital, which would only occur if there were no random fluctuation in the capacity level. The actual situation is more complex, but the basic principle still applies.

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It is useful to compare this conclusion with the Classic VOLL Design. The annual peak energy rent curve, PVR, which is strictly analogous to the Locational ICAP Demand Curve, has this same property. It is much steeper on the left than on the right. It has this property for exactly the same reason. The PVR measures the costliness of outages and tells us that downside mistakes are far more costly than upside errors. Its shape ensures that there will be relatively fewer downside errors. In summary, a key conclusion is that the Locational ICAP Demand Curve should be steeper to the left of its intersection with BCC than to the right of its intersection.

6. Adjusting the Locational ICAP Demand Curve to Reduce Risk

Q: IS RISK AN APPROPRIATE CONSIDERATION IN LOCATIONAL ICAP DESIGN?

A: Investing in power markets under deregulation has proven extremely risky, and has consequently made investors reluctant to invest. Although much of the current reluctance is simply the result of the market being oversupplied, there is ample evidence that the perception of risk is also playing a major role. Because investment risk is a major factor and because this risk derives in substantial part from fluctuations in the payments from the energy and capacity markets, the impact of the capacity market's demand curve must be considered.

Concern over market risk is secondary to the concern over reliability, but it is not a small matter. John Reed's testimony on BCC estimates that the required return on equity would be about 16% (15 to 17%) without Locational ICAP and will be about 12% with Locational ICAP. This is a cost saving of 4% on equity and with

50/50 debt-equity financing it is a cost savings of 2% per year on the total installed cost of generation.[11]

At this point it is important to remember that markets pay the clearing price to all sellers and not just to the marginal seller that sets the price. Thus all generation capital will be paid this same risk premium if we rely on a market to pay for capacity. So what is the total installed cost of the ISO's capacity? A precise answer is not needed, so I will take the cost per MW of installed capacity to be the cost of installing a pair of aero-derivative peakers in Maine. Surely this is an underestimate, at $880,000/MW.

The cost of the extra risk premium from not having Locational ICAP would then be 2%/year (half of the 4%/year reduction in the cost of equity) of this amount or $17,600/MW. For the ISO's 28,000 MW, this comes to $493 million per year.

Of course the estimated reduction in the cost of equity is not very accurate, but it represents a well-informed professional judgment. It seems unlikely that anyone can be sure the cost savings from implementing a successful Locational ICAP market would be less.

One way to put this cost savings in perspective is to note that it is sufficient to purchase 5,800 GW of capacity or about enough to cover 30% of the ISO's peak load. In other words, the disputes over reliability, which generally amount to under 5% of installed capacity, may have a price tag five times smaller than the risk savings from implementing Locational ICAP.

[11] I have assumed conservatively, with John Reed, that the cost of debt, which is affected less by market risk, is completely unaffected by the implementation of the new Locational ICAP market.

Although such a cost savings cannot be proven, it has not been and probably cannot be disproved, and it should not be ignored.

Q: WHY DOES THE CURRENT VERTICAL DEMAND CURVE IN THE ICAP MARKET INCREASE INVESTMENT RISK?

A: If the ICAP Demand Curve is vertical, the price in this market will swing from high to zero with a small change of installed capacity, thus the payout from the market is quite uncertain for suppliers. If the ICAP Demand Curve is nearly flat, the price will fluctuate little and the payout from this market will be nearly risk-free. This does not mean a flat demand curve is best, but it does mean that the steepness of the demand curve has an impact on the market risk of suppliers and that this effect deserves consideration when the demand curve is designed. It is also clear that this logic suggests a flatter demand curve than would otherwise be appropriate.

Q: HOW CAN LOCATIONAL ICAP REDUCE MARKET RISK RELATIVE TO THE CURRENT MARKET?

A: It can do this in two ways, (1) by using a demand curve which is less steep than the energy market's peak-energy-revenue curve and less steep than the current ICAP demand curve, and (2) by hedging energy revenues. The latter is accomplished with the Locational ICAP Payment formula as follows.

The most essential Locational ICAP equation is:

$$\text{Locational ICAP Payment} = \max(0,\ P(C_{ICAP}) - PER)$$

This means that the Locational ICAP Payment equals the Locational ICAP demand price determined by the current level of purchased capacity minus the

Peak Energy-Market Rents of the Benchmark Generator. If the result is negative, the Locational ICAP Payment is set to zero.

This method of computing and paying Locational ICAP neutralizes most of the effects of weather and outages. Either of these can force energy prices to spike, which adds to short-term profits. But when this happens it increases PER by approximately the amount of the increase in fixed-cost recovery. Because this is subtracted from the Locational ICAP Price, total short-term profits for all generators remain approximately unchanged. Thus, the risks of price spikes (or the lack thereof) from weather and outages are largely neutralized. This was illustrated by the example in the introduction. As the 1-Megawatt generator's energy rents fluctuated from $0.55 to $2.10/kW-month, the sum of its energy rents plus the Locational ICAP Payment only fluctuated from $7.05 to $7.10/kW-month. This is because Locational ICAP Payments are designed to cancel the risk in the energy market, and they will do a very good job of it.

The demand curve also reduces risk by being less steep than the revenue curve from the energy market. For example, if the installed capacity is reduced from C_{Target} to OC, shortages might increase by a factor of five and with them energy-market revenues. The Locational ICAP Demand Curve also causes a significant price increase in response to such a reduction of installed capacity, but the change is less.

Generators tend not to see price spikes as risky. But, the market will ensure that price spikes are averaged out by many lean years to give the right long-run average. That is what is happening now, and we find that generators find the inevitable flip-side of price spikes to seem risky indeed.

Risk is a cost of doing business and business recovers this cost as it recovers all costs, by charging more for its product. This is called a risk premium. Suppose the risk-free BCC is $6/kW-month. If investors know the market will pay this on average over the long run, but are afraid it will not pay it on average over the life of their project, they will not invest. Instead they will hold out for a higher price and this will drive up the effective BCC. In this way consumers are forced to pay the investor's risk premium.

In conclusion, the Locational ICAP Payment equation automatically hedges a great deal of energy-market risk, and a flatter Locational ICAP demand function reduces risk. Both effects lower BCC, and this cost savings is passed through to consumers.

Q: GIVEN THAT STEEPNESS INCREASES ACCURACY, AND LACK OF STEEPNESS REDUCES RISK, WHAT SHOULD BE DONE?

A: A tradeoff must be made that balances the two slope considerations for the selected Locational ICAP Demand Curve.

As I noted when discussing accuracy, steepness is needed more on the left because accuracy is needed more to prevent deficient capacity levels than to prevent surplus capacity. This improves the compromise because risk can be ameliorated with a flatter demand curve on the right, where accuracy is not as crucial.

It is impossible to calculate the optimal pair of slopes, so they must be selected after careful consideration of all of the above effects. After spending considerable time on this aspect of the design and making a number of simple calculations to check the essential properties of the tradeoffs involved, I have selected the slopes presented in this testimony. They represent my best professional judgment on this matter.

Although, more accuracy would be desirable, it should be noted that there is no indication that much could be saved with even perfect accuracy.

7. The Demand Curve's Effect On Market Power in the Locational ICAP Market

Q: WHY DOES MARKET POWER IN THE LOCATIONAL ICAP MARKET MATTER?

A: In Locational ICAP markets, the effect of market power is much more subtle than is commonly assumed. If a large supplier can raise the Locational ICAP Price by $1 when C equals C_{Target} that will induce others to build more capacity and C will increase to a level sufficiently above C_{Target} to cause the P_{LR} to fall back to BCC. Thus, market power in the Short-Run Locational ICAP market will not raise the Long-Run Locational ICAP Price; it will only raise the level of installed capacity above the level targeted by Locational ICAP. There will, of course, be a short-term price increase, and this cost could be significant.

(The market power discussed in the assumptions of Section 4 concerned market power in the investment market, not in the Short-Run Locational ICAP market. ~~That~~**Market power in the investment market** could raise the Long-Run Locational ICAP Price. Such market power is far less likely than short-run market power because it must restrict entry into the generation market. The market power under discussion here is in the short-run market.)

Another detriment of market power in the Locational ICAP market is that it makes it more difficult to set the Locational ICAP curve where it will induce the right level of capacity. As the exercise of market power comes and goes, the equilibrium level of installed capacity also fluctuates.

Because short-run market power could be severe in some Locational ICAP zones, the Locational ICAP design includes explicit tests for market power coupled with mitigation measures. These should largely take care of the problem. However, a flatter demand curve reduces market power and, thus, the extent to which mitigation measures will need to be invoked. A flatter curve means that the same amount of withholding will raise price less. This will have its most noticeable effect where the Locational ICAP Price is lowest because that is where market power is most likely to exist.

(Say a supplier can raise the Locational ICAP Price by 20 cents by withholding 10% of its capacity. If the initial Locational ICAP Payment is 10 cents, then the supplier loses 10% by withholding and triples its profit on the remaining 90%. This is profitable. If the initial Locational ICAP Payment is $10.00, then the supplier loses 10% by withholding and increases its profit on the remaining 90% by $0.20/$10.00 = 2% by raising the market price. Thus it not profitable as the 2% increase does make up for the 10% decrease, and it has no real market power.)

8. The Demand-Curve Formula

Q: WHAT ASPECTS OF THE DEMAND CURVE NEED TO BE DETERMINED?

A: That depends on the design. The simplest design would have only two parameters: slope and the intersection with EBCC. The proposed ISO demand curve has five parameters.

1. C_K, The C value at which the demand curve intersects EBCC.
2. The floor price.
3. The ceiling price.
4. The capacity where the ceiling price is reached.
5. The slope ratio: (slope when $C < C_K$) / (slope when $C > C_K$)

Q: HOW IS THE CAPACITY VALUE OF THE INTERSECTION WITH BCC DETERMINED?

A: It is crucial that the demand curve be set so that it intersects EBCC at a capacity level greater than OC.

The market cannot control installed capacity precisely and so it will fluctuate around its long-run average. An important source of fluctuations is the lumpiness of efficient capacity investments, both in generation and transmission. If the demand curve went through EBCC at OC, the long-run average would be near OC, and the actual capacity level would fluctuate around OC.

If it did, the actual capacity level would be below OC roughly half the time. That means reliability would be below the minimum acceptable level roughly half the time. Because this is unacceptable, Locational ICAP must be designed to secure more capacity on average. This higher average level is called C_{Target}.

To determine an acceptable C_{Target}, the past performance of the market was reviewed, and the distribution of actual installed capacity levels relative to OC was estimated for the previous 21 years.

The result of this review was that

1. The distribution of C values had a mean of $1.054 \times$ OC.
2. The standard deviation was 5.8%.
3. In 3 out of 21 years, the installed level was below OC.

Rather than rethink basic reliability policy during the Locational ICAP design, it was decided that C_{Target} should be set at the historical average level of capacity relative to OC, and the market should be designed to reproduce this level to the extent practical.

This gives us a relative C_{Target} of 1.054.

One final adjustment is needed. The value of capacity at the kink in the demand curve, C_K, should be set so that the average Locational ICAP Price is EBCC. Because C will fluctuate, we must position the demand curve so that P(C) averages to EBCC over the expected fluctuations. These are presumed to be drawn from a normal distribution with mean 1.054 and standard deviation 0.058. The result is a C_K of 1.038, which is 1.6% below C_{Target}.

Q: HOW IS THE FLOOR PRICE DETERMINED?

A: The floor has been set to $0/kW-month. At some high-enough capacity level, it makes sense to set Locational ICAP to zero. At the capacity level where this occurs, about 15% above OC, a Classic VOLL Design would provide peak revenues extremely close to zero.

At the point where Locational ICAP goes to zero, the ISO's energy market probably pays more than the Classic VOLL Design would pay. Shortage payments are probably greater than would be VOLL payments because shortage payments are paid when the system is still more than a Gigawatt short of shedding load. Although the payment is far less than VOLL, it is far more likely to occur.

In any case, there is essentially no difference between the Locational ICAP design and an ideal VOLL design once the Locational ICAP floor of $0 is reached. A significantly higher floor would diverge considerably from the VOLL design for high levels of capacity.

Q: HOW IS THE CEILING PRICE DETERMINED?

A: The ceiling price was selected to be symmetrical with the floor which is designed to underpay capacity by BCC. The ceiling overpays capacity by BCC. This should be sufficient to send a strong investment signal, but not strong enough to cost consumers a lot with no additional affect on investment.

The ceiling is high enough that when investors anticipate the market coming anywhere close to it they will want to invest in new capacity that becomes operable before that level is reached. Such timely investment should almost always prevent the ceiling from being reached.

This determination is not based on an exact theory but rather on common sense and expert judgment.

Q: HOW IS THE CAPACITY LEVEL WHERE THE CEILING PRICE IS REACHED DETERMINED?

A: Objective capability, OC is basically a lower bound on the normal operation of the market. Below that level, reliability is considered to be unacceptably low, and there will likely be intervention in the market.

Thus, the demand curve needs to reach the ceiling by the point at which installed capacity falls to OC, since the installed capacity level will probably not be allowed to go noticeably below that level.

Q: HOW IS THE SLOPE RATIO DETERMINED?

A: The slope ratio has been set to three, that is the slope when $C < C_K$ is three times greater than the slope when $C > C_K$. On the right side of C_K, the slope does not need to be particularly steep because the accuracy of C_{Target} is much less important above C_K than below C_K. Moreover, a flatter slope will reduce fluctuations in fixed cost recovery when installed capacity fluctuates, and this will reduce the investor's risk of cost recovery.

In keeping with the use of classic VOLL pricing as a model, also note that the revenue curve of a VOLL energy market will have a much flatter slope to the right than to the left of the point where it intersects BCC.

No precise answer can be given to the question of exactly what slope ratio is best, but we know it should be greater than one. The cost of too much installed capacity is considerably less than the cost of too little, so the slope ratio should be substantially greater than one.

Q: HOW IS C_{MAX} DETERMINED?

A: Notice that C_{Max} is not listed as one of the demand curves parameters. It is mathematically determined by the parameters already described. When determining C_K with the slope ratio set to three, C_{Max} is determined as a byproduct of that calculation.

Q: PLEASE PROVIDE THE EXACT FORM OF THE DEMAND CURVE THE ISO IS PROPOSING.

A: At this stage I would like to present the demand curve as if it were to be used for a single region, and on an annual basis. Subsequently I can add the details required for complications. One complication I will not describe is the regional aspect of Locational ICAP, which will be covered by Mark Karl, who also testifies for the ISO. However, it should be noted that the demand curve has the same shape in each region, so the relative parameters given below are the same in each region. The value for OC and EBCC will differ by region.

Variable and function definitions:

EBCC	The estimated fixed costs of the Benchmark Generator
C	Capacity
OC	Objective Capability, the minimum capacity needed for reliability
C_{Max}	The capacity value at which P(C) = 0
C_{Target}	Target long-run average C (Initially set to historical average)
SD	The estimated standard deviation of C
C_K	Capacity at the kink in demand curve
P	The Locational ICAP Price in $/kW-month
P(C)	The Locational ICAP Demand Curve

The formula for the demand curve is:

$P(C) = EBCC \times 2$, for $C < OC$

$P(C) = EBCC \times [1 + (C_K – C) / (C_K – OC)]$, for $C < C_K$

$P(C) = EBCC \times [1 + (C_K – C) / 3(C_K – OC)]$, for $C > C_K$

$P(C) = 0$, for $C > C_{Max}$

C_K is determined so that the expected value of P(C) = EBCC when C takes values that are normally distributed around C_{Target} with standard deviation SD.

Current relative values:

OC = 1.000
C_{Target} = 1.054
SD = 0.058
C_K = 1.038 (calculated as described above.)

Q: PLEASE PROVIDE A GRAPHICAL REPRESENTATION

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Q: HOW WILL C_{TARGET} AND C_K BE KEPT UP TO DATE?

A: Historical data have been used to determine C_{Target} and the standard deviation, SD, used in the determination of C_K. These are not the ideal statistics because the sample is drawn from years before a Locational ICAP market was in effect, and Locational ICAP can be expected to change the distribution. We are expecting it to narrow the distribution, so the estimates should be on the cautious side.

Both C_{Target} and SD will be updated each year as new, and more relevant, data is gained. The update procedures are as follows:

$d = (C - C_{Target})^2$

will be computed, and V will be adjust to

$V = 0.9 \times V_{-1} + 0.1 \times d$

where V_{-1} is the previous SD^2 of the distribution of capacities.

SD will then be updated to $SD = \sqrt{V}$.

$C_{Target} = 0.8 \times (\text{Previous } C_{Target}) + 0.2 \times C^*$, where $C^* = 1 + SD$

In this way C_{Target} and SD will gradually take account of the evidence from the new market with regard to the uncertainty in the distribution of actual capacity values. Technically this forms an exponentially weighted moving average of the means and variances. C* is calculated to cause C_{Target} to approach one standard deviation above OC, which will give an 86% chance of finding C > OC, which conforms to the historical data.

9. The Demand Curve's Relationship to other Design Features

Q: HOW DO THE OTHER PARTS OF THE LOCATIONAL ICAP MARKET RELATE TO THE DEMAND CURVE?

A: The Locational ICAP market comprises 7 major design areas all of which utilize or refine the demand curve:

1. The structure of the Locational ICAP Demand Curve
2. The bidding and market-power mitigation rules
3. The determination of the Locational ICAP Payment
4. The adjustment for actual availability

5. The division of annual into monthly Locational ICAP
6. The locational mechanisms
7. The accounting and settlement procedures

I have already covered the first of these, and I will not cover the last two.

Q: HOW IS THE DEMAND CURVE USED TO ACCEPT AND PRICE BIDS?

A: Mark Karl, who also testifies for the ISO, has described how the demand curve works in relation to the capacity auction, but I will describe it briefly for context here.

In an optimal situation, market participant owners of capacity resources will offer UC_B, and a bid price P_B, where each offer-price pair is associated with a specific unit. Also associated with each unit is an underlying seasonal claimed capability value, which is known to the ISO. These underlying capacities are associated with their corresponding bid prices and a supply curve is constructed such that the offer reflects the underlying capability of the resources offered.

The intersection of this supply curve with the Locational ICAP Demand Curve is used to determine C_{ICAP}, the total Locational ICAP capacity purchased and the Locational ICAP Price. This description requires that offers be associated with specific resources. However, as described in the testimony of Mark Karl, the multiple ownership of resources in New England may dictate a portfolio offer process.

Sellers are paid for their capacity at the Locational ICAP Payment rate reduced by an availability factor that will be described shortly. Thus if a supplier sells 100 Megawatt of ~~unforced~~ capacity and the Locational ICAP auction clearing price is

$7/kW-month, that will be used to compute a Locational ICAP Payment. If the energy market rent (PER) of the operational Benchmark Generator is $2/kW-month, then the Locational ICAP Payment rate is $5/kW-month. If the generator actually produces a weighted average of 102 Megawatt during the Critical Hours, it is paid for 102 Megawatt at $5/kW-month.

Q: HOW WILL MARKET POWER BE MITIGATED IN THE LOCATIONAL ICAP MARKET?

A: Because the suppliers in some zones will have high market shares, the exercise of market power would be expected if rules for its mitigation were not implemented. Mitigation will proceed as follows:

1. A supplier is deemed to have market power in a zone if the supplier has a unilateral incentive to withhold capacity assuming a marginal cost of zero, and all others offer their full capacity at zero.
2. A supplier that is deemed to have market power must bid in all of its capacity at some price, and must justify any price above $1/kW-month.
3. Other suppliers' bids are not restricted.

Q: HOW IS THE LOCATIONAL ICAP PAYMENT DETERMINED?

A: The Locational ICAP Payment is determined by subtracting certain Peak Energy-Market Rents[12] from the Locational ICAP Price which is set relative to BCC. Obviously these two quantities must be calculated in a consistent manner

[12] Unlike Peak Energy-Market Rents, forward-reserve-market revenues are not ~~subtractracted~~**subtracted** from the Locational ICAP price because they pay for additional costly obligations beyond simply providing capacity and energy.

if the subtraction is to produce a reasonable result. Consequently, the PER and the Locational ICAP Price should be based on the same Benchmark Generator.

To understand the selection of the Benchmark Generator and the definition of BCC and PER, some economic theory is required.

Q: CAN YOU EXPLAIN THE ECONOMIC THEORY OF THE BENCHMARK GENERATOR?

A: Yes, with the help of the Classic VOLL Design, I can. Consider such a market in long-run equilibrium with four efficient kinds of technology, baseload (G0), shoulder (G1), “bottom” peaker (G2) and the “top” peaker technology (G3).

When shoulder plants (G1) are on the margin, only baseload earns inframarginal rent, and I will call this rent ER0 because it is earned only by baseload, G0, generators. Note that rent is not revenue, but revenue less variable cost. Thus, when G0 sets the price it earns revenues, but no rent.

Similarly, there are shoulder inframarginal rents (ER1) which are earned only by shoulder and baseload plants and bottom-peaker rents (ER2), which are earned by all three. Finally, there are VOLL price spikes which are received by all four technologies and I will call these revenues, SR_{VOLL}.

Because the market is in long-run equilibrium each type of technology exactly covers its fixed costs. Thus

1. $FC0 = ER0 + ER1 + ER2 + SR_{VOLL}$
2. $FC1 = ER1 + ER2 + SR_{VOLL}$
3. $FC2 = ER2 + SR_{VOLL}$

4. $FC3 = SR_{VOLL}$

Next we cap the market so SR_{VOLL} is decreased to SR_{Capped}, and:

5. $FC0 > ER0 + ER1 + ER2 + SR_{Capped}$

6. $FC1 > ER1 + ER2 + SR_{Capped}$

7. $FC2 > ER2 + SR_{Capped}$

8. $FC3 > SR_{Capped}$

In our theoretical market, the cap decreases the energy revenues of every type of generator by exactly the same amount because all are running on peak and all receive the same energy spike rents whether the spikes are capped or uncapped. The purpose of an ICAP market in this model is to replace the revenues that are lost by capping the price spikes.[13] The Locational ICAP Payment should therefore be

9. $LP = SR_{VOLL} – SR_{Capped}$

This means the Locational ICAP Payment should equal the VOLL energy spike rents minus the capped energy spike rents. This is a theoretical value that cannot be used directly in the design of the market. Instead I will show that a certain value that can be calculated and used is equal to this theoretically correct value. To compute the BCC and PER, a benchmark technology must be selected. Fortunately, any one of these four efficient technologies will do. All are needed in an efficient market, and the market will, over the long run, build some of each.

[13] In reality, part of these revenues have been replaced by shortage prices in the energy market, and this is taken into account in the ISO’s Locational ICAP design.

From time to time each one of these will make a "new entry" into the market, so any one of them can serve as the benchmark.

As an example I will choose G2, the bottom peaker, as the benchmark technology (though in practice choosing the top peaker makes the energy rent calculation more transparent and accurate).

Given this choice of a benchmark technology,

10. $BCC = FC2$, the fixed costs of G2,

11. $PER = ER2 + SR_{Capped}$, the energy-market rent of G2.

I will now show that using BCC and PER to calculate the Locational ICAP Payment as previously described will cause the Locational ICAP Payment to equal the theoretical value $SR_{VOLL} - SR_{Capped}$ exactly as it should.

12. $LP = BCC - PER$

Substituting in for BCC and PER from 10 and 11 above, we have

13. $LP = FC2 - (ER2 + SR_{Capped})$.

Substituting for FC2 from equation 7 above,

14. $LP = (ER2 + SR_{VOLL}) - (ER2 + SR_{Capped})$,

which simplifies to

15. $LP = SR_{VOLL} - SR_{Capped}$,

This says that if the Locational ICAP Payment is (BCC – PER), which it will be when $C = C_K$, then it will equal the gap between any generator's fixed cost recovery under the ISO's energy market and fixed-cost recovery in a Classic

VOLL Design, which is full recovery. This is just what is needed to make all technologies whole for the capping of the price spike.

Technology 2, the bottom peaker was chosen arbitrarily to illustrate the theory of efficient price-spike replacement, but the same proof will show that any of the four efficient technologies can be chosen and used in the same way. Each would give a different BCC and so a different Locational ICAP Demand Curve, but each would also give a different PER. Subtracting PER from BCC would give the same answer in each case, and it is this difference that determines the Locational ICAP Payments, so these payments would be the same in each case.[14]

The important step in choosing a benchmark technology is to choose one that is economically efficient—that will be built by the market. Choosing the efficient technology with the highest marginal cost only makes the energy-market rent calculation more accurate and the incentives mimic a VOLL market a bit more closely. Any efficient technology gives the right signals in equilibrium and leads the market to the correct equilibrium.

This analysis clears up a common misconception. If the more expensive (per Megawatt of capacity) aero-derivative peaker technology were chosen instead of the cheaper frame technology, the Locational ICAP Demand Curve would be much higher. But this does not mean the Locational ICAP Payments would be higher. On average the energy rents of an aero-derivative peaker would be just as much higher **than** those of a frame unit as its capacity costs are higher than those of a frame unit. The result would be the same Locational ICAP Payments once benchmark energy rents were subtracted from the BCC. Frame units were chosen as the benchmark, not to save consumers money or to reduce profits, but to increase the accuracy of Locational ICAP Payments.

Note that choosing efficient technology G2 instead of efficient technology G3 results in shifting BCC up by ER2 and PER up by ER2; consequently it leaves the Locational ICAP Payment unchanged.

Q: HOW DOES THIS THEORETICAL MODEL TRANSLATE INTO THE ACTUAL DETERMINATION OF LOCATIONAL ICAP?

A: The translation is completely straight forward.

1. The highest-marginal cost generator that is also economically efficient should be selected as the Benchmark Generator.
2. EBCC should be set to the annualized fixed costs of the Benchmark Generator, and adjusted for the estimated forced outage rate of the relevant type of generation.[15]
3. PER should be set at the end of each Locational ICAP year to the energy and shortage revenues such a unit would have collected had it been 100% available minus its variable costs. (Variable costs are those that would not have been incurred had it not run at all.)
4. LP = BCC – PER.

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[14] Different benchmark technologies will produce different LPs when the market is out of equilibrium, but these still lead the market back towards equilibrium and provide the same long-run outcomes.

[15] Thus if the Benchmark Generator has annualized fixed costs of $10/kW-month, and a forced outage rate of 10%, its EBCC = 10/0.90.

Unlike in the theoretical model, some of the Peak Eenergy-Market Rents will come from prices set by older generators and by shortage prices.

~~Not surprisingly, it also~~**The Benchmark Generator** has the highest variable cost of any economically efficient technology. This means its energy rents (revenues minus variable costs) will be the smallest and thus the least prone to estimation error when that is measured in dollars and not as a percentage. Since the Locational ICAP Payment is computed by subtracting these energy rents from the unit's fixed cots, this smaller dollar error translates into a more accurate Locational ICAP Payments

(Notice that the highest-marginal-cost unit is also the lowest-fixed-cost unit. If it were not, there would necessarily be some other unit with lower fixed costs and lower marginal costs. In this case, the selected benchmark unit would not have been an efficient unit and was improperly selected. Therefore a properly selected benchmark unit with the lowest marginal cost will also have the highest fixed costs.)

Q: WHAT IF BCC IS MISESTIMATED?

A: Because the Long-Run Locational ICAP Price is determined by investors and their estimates of BCC and not by our estimates, misestimating BCC will have no effect on the Long-Run Locational ICAP Price. Instead it will cause investors to build more or less capacity as they force the Locational ICAP Price to equal BCC. This will cause us to miss our capacity target, but it will have no impact on the Long-Run Locational ICAP Price.

The Locational ICAP Demand Curve has been designed with such possible errors in mind and is intended to limit their effect on the equilibrium level of installed capacity.

Q: SHOULD EBCC TAKE ACCOUNT OF TEMPORARY DISCOUNTS OR PREMIA ON THE COST OF NEW HARDWARE?

A: In the long-run taking account of such fluctuations will do no harm because we must expect the price of generation hardware to equal its all-in cost of production in the long-run. Similarly, it should not help for the same reason. The principle argument against taking account of such transient phenomena is that it is a difficult and ambiguous procedure and so opens the door to controversy and manipulation. For this reason, and because there is nothing to be gained, it should not be attempted.

Q: DID YOU CONSIDER USING ESTIMATED INFRAMARGINAL RENTS INSTEAD OF ACTUAL INFRAMARGINAL RENTS?

Yes, that was considered first. There are two possible approaches.

1. At the beginning of the Locational ICAP contract year, a prospective estimate of Peak Energy-Market Rents could be subtracted from the Locational ICAP Price to give the Locational ICAP Payment.

2. At the end of the Locational ICAP contract year, a retrospective estimate of Peak Energy-Market Rents could be subtracted from the Locational ICAP Price. If this approach is used, **an** approximate ~~the~~ Locational ICAP Payment could be made on a monthly basis with a true-up at the end of the year.

While the two approaches give almost the same payments on average and thus induce almost the same level of installed capacity, there are several advantages to the second approach.

Q: WHAT IS THE MAIN ADVANTAGE?

A: Estimating rents retrospectively is vastly simpler. The most difficult task in the prospective estimate is predicting the weather, unplanned generation outages and exercises of market power. These must then be interacted with all the normal complexities of supply and demand to find the hourly market price. Retrospectively, the hourly price is known exactly and all this is avoided.

Knowing the market price, estimation of PER requires only an estimate of the benchmark technology's variable cost, which is primarily determined by its fuel costs. Compared to energy price forecasts, the errors in this process will be modest and the estimation process will be much more transparent and less controversial.

Q: WILL RETROSPETIVE ESTIMATION SAVE CONSUMERS MONEY?

A: Because the retrospectively-estimated PER will not be subject to large errors in forecasting the energy price, the Locational ICAP Payment will be less risky.

Using prospective estimation, suppose the estimate of PER is $3/kW-month, but the actual value could be anywhere from $1 to $5/kW-month (a 1-SD range). If the Locational ICAP Price were $7 and PER turned out to be $5, the Locational ICAP Payment, LP, would still be $7 – $3 = $4/kW-month, which combined with the energy market rent would total $4 + $5 = $9/kW-month. This would be the fixed-cost recovery of an actual Benchmark Generator. However, if PER turned out to be \$1, the total LP + PER would be \$4 + \$1 = \$5/kW-month—a difference of \$4/kW-month.

Using retrospective estimation will result in almost that exact PER being subtracted from the Locational ICAP Price, so an actual Benchmark Generator would cover \$7 – \$5 + \$5 = \$7/kW-month of fixed costs or \$7 – \$1 + \$1 = \$7/kW-month, depending on whether PER turned out to be \$1 or \$5. Because the result is the same either way, there is no risk to generation or load.

Making investment less risky lowers the risk premium and this savings will be passed on to consumers.

Q: WHAT ABOUT CONSUMER RISK?

A: Approach #2 reduces the risk to load. Load must pay both Locational ICAP Payments and Peak Energy-Market Rents, so, to the extent these are stabilized for generation, they are also stabilized for load.

Q: YOU HAVE MENTIONED AN IMPACT ON SPOT-MARKET POWER; CAN YOU EXPLAIN THAT?

A: Approach #2 neutralizes a great deal of market power in the spot market for the simple reason that generators who have sold Locational ICAP cannot profit from an increase in the shortage price, nor can they profit from the highest energy prices. These increase PER, and so they are subtracted from the Locational ICAP Payment. What the energy market gives to an exercise of market power in one of the Critical Hours, the Locational ICAP market takes away. (Taking the spot energy price as given, failing to produce still lowers their energy revenues and leaves their Locational ICAP Payment unaffected, so generators are still properly motivated by shortage prices.)

Having adopted approach #2 the formula for the Locational ICAP Payment is:

PER	Annual Peak Energy-Market Rents associate with the benchmark generator	
The formula for the demand curve is:		
LP	$= P(C_{ICAP}) - PER$	The Locational ICAP Payment

Q: THE COMMISSION HAS DIRECTED THIS HEARING PROCESS SHOULD "ARRIVE AT A FINAL LICAP MARKET DESIGN THAT WILL APPROPRIATELY COMPENSATE GENERATORS NEEDED FOR RELIABILITY AND ATTRACT AND RETAIN NECESSARY INFRASTRUCTURE TO ASSURE LONG-TERM RELIABILITY." HOW WILL THE PROPOSED LOCATIONAL ICAP MARKET ENHANCE RELIABILITY?

A: One of the ways the Locational ICAP market will enhance reliability is by compensating generators who are there when power is needed and not compensating those generators who are not.

Q: WHAT QUALIFIES LOCATIONAL ICAP CAPACITY TO RECEIVE LOCATIONAL ICAP PAYMENTS?

A: The short answer is: by providing capacity when it is most needed. The current Locational ICAP proposal is based on competitive theory as embodied in the model of VOLL pricing. This theory and model give specific guidance on who should be rewarded with Locational ICAP Payments.

Because Locational ICAP Payments are a replacement for missing Peak Energy-Market Rents, the generators should receive Locational ICAP Payments almost to the same extent they would have received Peak Energy-Market Rents under a VOLL pricing model. This means they should only receive them during shortage hours or near-shortage hours, and the extent of the payment should be limited to the extent that the resource can provide energy or reserves in the Critical Hour.

Although I focus on generators as the supplier of Locational ICAP, I should note that dispatchable load is also able to supply Locational ICAP to the extent that it provides reserves. Allowing participation in the Locational ICAP market by dispatchable load is important in providing efficient incentives for demand response.

As with all prices in a competitive market, there is logic to paying high prices to generators that are running during a shortage. These are the generators that guarantee the installed capacity will actually cover the needs of load. A generator that is available during half of the shortages is worth about half a generator when considering the installed capacity requirement.[16] With two such generators you can almost cover your needs as well as with one fully available generator. (The apparent problem that both might be out at the same time is due to considering an

[16] To see that this is a good approximation, consider a market with 100 generators each of which is available 50% of the time. On average, 50 generators will be available and with 85% probability, 60 will be available. If we add one generator that is available 50% of the time, these figures will go up to 50.5 generators and 60.6 generators. If we add a half generator, they will go up to 50.5 generators and 60.5 generators. Thus adding a half generator to a large system is very similar to adding one generator that is available half the time.

example with only two. In a real market with many generators, this problem becomes negligible and generators are correctly valued by the fraction of their capacity that they deliver on average during shortage hours.)

Being available during a selection of roughly 100 Critical Hours is what will qualify Locational ICAP capacity to receive the Locational ICAP Payment. If the generator provides a weighted average F of the capacity sold in the Locational ICAP market during the Critical Hours it will receive a fraction F of the Locational ICAP Payment.

Q: WHAT CONCRETE BENEFITS WILL THIS SYSTEM OF LOCATIONAL ICAP REWARDS HAVE?

A: Rewarding those generators who provide capacity, will encourage **investment in capacity that is appropriately reliable**, rather than in capacity that is cheap to build but expensive when reliability contribution per dollar of investment is considered. When reliability is provided more cheaply, consumers end up paying less. If they are forced to pay for inappropriate capacity, their rates will not be just and reasonable.

A second benefit is additional incentive for plants that can contribute little to reliability to retire. It would not be just and reasonable for load to be required to subsidize such plants, especially when subsidizing them can only be done by subsidizing all generation.

The third benefit accrues to generation. Suppose a region has a C_{Target} of 5,000 Megawatts of generation, but has 5,500 Megawatts of installed capacity. Its Locational ICAP Price will be roughly \$3.30/kW-month. If 300 Megawatts of capacity retires, this will rise to roughly $7.50/kW-month, which will be of great benefit to existing generators. Retiring generation that does not perform will lead to a more substantial and efficient reward of generation that performs well.

Q: CAN YOU PROVIDE A MORE DETAILED DESCRIPTION OF THE AVAILABILITY ASSESSMENT PROCEDURE?

A: Each of the "critical" hours is assigned a weight, W_H. All shortage hours are included. The remaining Critical Hours are made up from the hours with the highest energy prices.

Weights for hours are determined by three factors (1) real-time energy prices divided by daily gas prices, (2) 10-minute reserve margins, and (3) 30-minute reserve margins. The N hours with the highest weights are designated critical hours. N changes linearly from 50 to 100 as the Locational ICAP Price moves from $0 to EBCC, and linearly from 100 to 200 as the Locational ICAP Price moves from EBCC to 2×EBCC as shown below.

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A generator's availability factor, A_G, is determined from all critical hours in all months for which the generator could have sold Locational ICAP to the ISO. (If a new generator ~~may appear~~**appears** in late June, January through June are not included in the average.) The availability factor is the weighted average available capacity, over critical hours, weighted by the criticalness weights. If A_G equals one, the generator is paid the nominal Locational ICAP payment for the month times the capacity it sold to the Locational ICAP market. If A_G is more or less than one this payment is changed in proportion to A_G.

Variable and function definitions:

LP_M	Monthly nominal Locational ICAP Payment
W_H	The criticalness weight for hour H, $W_H = 0$ in non-critical hours.
W	The sum of W_H over all hours of the year
C_G	The accepted capacity bid of a certain generating unit
C_{GH}	Generating unit G's output in hour H of energy and reserves
A_G	The annual availability factor of generator G.

The Availability Adjustment Rule:

An accepted bid, will be paid $A_G \times LP_M \times C_G$,

where $A_G = (\Sigma_H C_{GH} \times W_H) / W$,

and the sum is over all hours in which ICAP could have been sold.

A Proposed Calculation of Criticalness Weights:

$W_H = 2 \times z(P_E/P_G) - z(M_{10}) - z(M_{30})$, where

z(.)	The z-score of the variable over the year.[17]
P_E	The real-time hourly energy price,
P_G	The daily gas price,
M_{10}	The ten-minute reserve margin,
M_{30}	The thirty-minute reserve margin.[18]

Q: DEFINING THE MONTHLY MARKETS

Monthly markets are needed to accommodate shifts in load amongst wholesale load serving entities.

Installed capacity is more valuable in some months than others. This is apparent from the fact that there are more shortage hours in some than others. Often there is a peak-load month which is the main determinant of the system's capacity requirement. Selling Locational ICAP monthly requires several adjustments to the

[17] The standardized variable is (original variable – mean of variable)/(standard deviation of variable).
[18] The ten-minute reserve margin is the actual ten-minute reserve capability less the ten-minute reserve requirement (both include ten-minute spin and non-spin). The thirty-minute reserve margin is the actual

annual approach that I have implicitly assumed up to this point. These are the basic changes:

1. Bidding will be monthly instead of annually.

2. The monthly Locational ICAP Price will be (W_M /W)× P, where P is the annual Locational ICAP Price and W_M is the monthly weight with the sum of these equal to ~~1.~~W.

3. W_M will be the amount of Locational ICAP that will be paid to a fully available Megawatt in that month~~ divided by~~, and W will be the fully available annual Locational ICAP Payment.

4. Peak Energy-Market Rents will be subtracted on a monthly basis.

AG, a generation unit's availability factor will still be computed on an annual basis, but applied monthly.

Variable and function definitions:

W_M	The sum of W_H over the hours in month M
C_M	Capacity purchased in month M
P_M	$= P(C_M) \times (W_M / W)$
PER_M	= Actual Peak Energy-Market Rents for month M
LP_M	$= P_M - PER_M$

The Monthly Payment Rule:

An accepted bid, will be paid $A_G \times LP_M \times C_G$ for month M.

thirty-minute reserve capability less the thirty-minute requirement (both include ten-minute spin and non-spin plus thirty-minute operating reserves).

Q: HOW IS THE AVAILABILITY FACTOR ADJUSTMENT APPLIED TO IMPORTS OF CAPACITY?

A: The process described above may not be directly applicable to imported capacity because such imports may last only a single month and that resource may not offer again in the New England market. In addition, it is the actual availability of energy delivered to the New England border during Critical Hours which ensures reliability, and the availability of the exporting resource in its native region during New England Critical Hours may or may not be correlated with the actual delivery of energy at the New England border. Imported capacity may therefore require an availability adjustment process slightly different from the process applied to internal resources, but it is essential that any such process must comply with the principle that capacity should be compensated for delivery during times of system need.

10. Why Pay Existing Generators?

Q: GIVEN THAT WE NEED NEW CAPACITY, WHY PAY EXISTING CAPACITY?

A: First consider once again the Classic VOLL Design which we know to be **a** well designed market at its core. Such a market would clearly not price discriminate in the slightest against existing capacity. In fact it would be hard to find a competitive market that did price discriminate against existing capacity.

Sometimes this question means just what it says, but sometimes it is directed at specific types of generators that are more than covering fixed costs.

Q: CONSIDER THE BASIC QUESTION FIRST: WHY PAY EXISTING GENERATORS WITH NORMAL PROFITS?

A: The purpose of the ICAP market, and indeed one of the main purposes of the energy market, is to signal future investors that if they build new generation up to the required level of capacity, they will be paid a normal rate of return on their investment. At the start of a new Locational ICAP market, it might be possible to make a rule that every new generator and only new generators will receive Locational ICAP Payments.

It would not be surprising if average Locational ICAP Prices were, in the long run, about $8/kW-month, and if PER were about $2/kW-month. In this case, any existing generator with normal fixed costs would find itself short by $6/kW-month of recovering its fixed costs. Under a new investors-only design, the old investments' losses would be the consumers' gain.

This is not a surprising possibility. Any time there are sunk costs, they can be taken if they are not legally protected, because the market cannot protect them. Unlike variable costs, the supplier cannot choose to avoid them. It is too late. Fixed costs are always at risk to market redesign, but there are three reasons not to take advantage of this situation.

1. The possibility of legal recourse.
2. Fairness.
3. Investors do not look favorably on such maneuvers.

It might be possible to convince future investors that although New England is taking advantage of existing generators it would certainly not treat present investors this way when they become existing generators. But then again, it might not.

Economics teaches that it is best not to pursue such policies. Alfred Kahn terms them kleptocratic. I know of no proof that load as well as existing generators would turn out to be poorer as a consequence, but I would not recommend such an experiment. If investors assume they will fare as well on average as past investors have fared, their risk premiums will cost consumers about as much as consumers will gain by expropriating the sunk cost associated with existing investments.

Q: NOW CONSIDER THE CASE OF GENERATORS THAT ARE MORE THAN COVERING THEIR FIXED COSTS

A: Under regulation, smart or lucky suppliers are not allowed to make any more than normal profits—or at least little more.

In any unregulated market, smart suppliers, with low costs, and lucky suppliers with low costs both make super-normal profits. It is important that smart suppliers be rewarded, but not that lucky ones be rewarded. Unfortunately, it is extremely difficult to tell who was smart and who was just lucky. Markets are efficient because they reward smart investors, and rewarding lucky ones does little to harm this efficiency.

If regulators try to take back windfall gains without subsidizing suppliers who have windfall losses, the market will view this as regulatory risk and raise the cost of capital.

Worse yet, such a policy will lead consumers to lobby the regulators to label the extra profits of the most efficient generators as windfall-gains and confiscate them. In the short run, this will save consumers money. In the long-run it will be destroy market incentives and market confidence and will be **an** expensive policy.

11. Rights and Obligations of Purchased Locational ICAP

Q: WHAT IS THE PRODUCT DEFINITION FOR INSTALLED CAPACITY?

A: Sellers of Locational ICAP have two primary obligations:

1. They must bid as much power as they have capacity into the day-ahead market, or export it
2. They are subject to recall when they export energy.

Sellers of Locational ICAP have a right to Locational ICAP Payments computed by the methods previously described. In particular, they will only be paid in proportion to their availability during Critical Hours weighted as previously described.

12. Exporting and Importing Locational ICAP

Q: TO WHAT EXTENT DO THE PARAMETERS OF THE DEMAND CURVE USED BY THE NYISO AFFECT THE ABILITY OF NEW ENGLAND TO ATTRACT LOCATIONAL ICAP CAPACITY, AND THUS, HOW SHOULD THE NEW YORK PARAMETERS AFFECT THE PARAMETERS FOR NEW ENGLAND?

A: Suppose that the actual cost of new capacity in both locations were $7/kW-month, but the NYISO believed it was $10/kW-month, while the ISO correctly assessed it at $7/kW-month. Further, suppose that the NYISO and the ISO each had exactly their targeted level of capacity. What would happen? The NYISO would tend to set its capacity price at $10, but this would attract some capacity from the ISO. This would raise the price in New England to a little more than $7 (perhaps significantly more locally), and it would lower the NY price to something a little less than $10.

This would induce a little investment in New England over the next few years and also more in New York. Because both markets have downward sloping demand curves that correct fairly quickly for costing errors, the equilibrium prices in the two areas would soon be hovering around $7/kW-month. The only problem that would linger would be some excess capacity in New York, due to their misplaced demand curve.

If there were an actual and persistent cost difference between the two regions, the low-priced region would find itself continuously exporting capacity to the high cost region (which is what should happen). Both regions would find their long-run

Locational ICAP Prices equal to their costs of new entry, and provided they had independently targeted their demand curves correctly, each would find itself with the right amount of new capacity. Downward sloping demand curves should make the adjustments happen quite smoothly.

It should be noted that even though the long-run outcome of the export situation is efficient, it can have a short-run effect. In the short run, consumers in the low-price region can have their prices raised by suddenly being placed in competition with a high-priced region. The introduction of trade should be beneficial in the long run. If the trade is allowed to develop predictably and with enough time for new entry, this step up in rates should be avoidable.

The only possibility for one market interfering with the other comes from the possibility that one could buy capacity for only a small fraction of the year and thereby obtain full benefit without paying full price. This would be possible only if one of the markets did not protect itself on this count and the other market was able to take advantage of this failing.

The New England Locational ICAP market is designed to prevent this type of detrimental interaction. It allows local Locational ICAP capacity to export power without penalty on over 97% of annual hours even when ~~it~~**the ISO** is nearly short of capacity. Even on these few hours, generators can sell power out unless there is an emergency, although they will lose some of their Locational ICAP Payment for exporting during a Critical Hour. They can also leave the New England Locational ICAP market during any month and export their capacity. Of course if they do this during the peak month, they will be heavily penalized since this makes their capacity nearly useless for meeting annual peak load. A more sensible approach would be for capacity to leave for the whole year, and for this there is no penalty, only the opportunity cost of leaving the ISO's Locational ICAP market.

In the other direction, the ISO's design makes no attempt to steal capacity from poorly designed neighboring markets. Instead it again favors annual imports when they are needed, a practice which favors efficient trade between regions.

Q: WHAT IS MOST NOTABLE ABOUT THE DESIGN IS THAT COMPATIBILITY WITH OTHER REGIONS IS INHERENT IN THE DESIGN AND IS NOT DEPENDENT ON PARAMETER VALUE?

A: As long as the market parameters sensibly reflect the ISO's needs, the ISO's Locational ICAP market should neither be taken advantage of by other regions nor be taken advantage of.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

Glossary

Actual Average Price, AAP

The long-run average of the actual (realized) Short-Run Locational ICAP Prices.

A_G

The annual availability factor of generator G. One if it supplies what it sells as Locational ICAP. It can be greater than one.

Average Peak VOLL Energy Rents, PVR

The energy revenues that would be earned by the Benchmark Generator above its variable costs under the Classic VOLL Design in an average year with the given level of installed capacity.

Benchmark Cost of Capacity, BCC

The annualized fixed costs of the Benchmark Generator. (See also EBCC).

Benchmark Generator

The generator selected for the determination of BCC and PER. A generator that the market will build, not an out-of-date or impractical one. For accuracy of inframarginal-rent calculations the efficient generator with the highest variable cost has been selected.

Bid Price, P_B

The price of capacity bid by a supplier in a monthly Locational ICAP auction.

C

Actual installed capacity or the value of the capacity bid into the Locational ICAP auction.

C_G

Generating unit G's accepted capacity bid.

C_{GH}

Generating unit G's output in hour H.

C_{ICAP}

The total Locational ICAP capacity purchased.

C_K

The point at which the demand curve passes through the level of the estimated cost of new entry, EBCC.

CONE

Cost of new capacity. CONE has been changed to BCC.

C_{Max}

The capacity level at which the Locational ICAP Demand Curve falls to zero.

Classic VOLL Design

A design in which the market sets the spot price at the intersection of the supply curve and the demand curve except when they do not intersect, and then it sets the spot price to the value of lost load.

Critical Hours

Hours in which the system is most in need of capacity and which meet a certain test criterion and are therefore designated as hours in which Locational ICAP is paid. Each such hour is assigned a weight according to its criticalness and the Locational ICAP Payment for that hour is proportional to that weight. There will be between 50 and 200 such hours depending on the Locational ICAP Price.

Estimated Benchmark Cost of Capacity, EBCC

The value of BCC as estimated for use in constructing the Locational ICAP Demand Curve.

SR_{Capped}

Capped energy spike rents.

SR_{VOLL}

VOLL energy spike rents.

Expected Average Price, EAP

The long-run average price expected by investors. EAP is the investors' expected value of AAP.

Inframarginal Rents

The rents accruing to generators whose variable cost of production is less than the marginal cost of the marginal generator, and thus less than the market price. Baseload generators earn inframarginal rents when a peaker is on the margin.

Locational ICAP Demand Curve, P(C)

With the bid-in capacity supply curve, this determines the Locational ICAP Price. Left of OC it has height 2×EBCC. It drops linearly to EBCC at C_K, then linearly with 1/3 of the previous slope to zero at C_{Max}. C_K is chosen so that a normal distribution of installed capacities with mean C_{Target} and standard deviation SD determines an average Locational ICAP Price of EBCC.

Locational ICAP Payment, LP

The Nominal Locational ICAP Payment correct for availability.

Locational ICAP Price, P

As distinct from the Locational ICAP payment, this is the value determined from the Locational ICAP demand curve and so includes both the Locational ICAP Payment and Peak Energy-Market Rent (PER).

Locational Marginal Pricing, LMP

The system of competitive pricing in which price is set to locational marginal cost. .

Total Cost
Fixed costs plus variable costs.

Total Revenue
A generator's energy revenues plus its Locational ICAP revenues.

Long-Run Locational ICAP Price, P_{LR}
The equilibrium price of a market in which the capacity level has plenty of time to adjust in response to the Locational ICAP Demand Curve, which is assumed to be static. It can also be thought of as the theoretical long-run average of Short-Run Locational ICAP Prices.

Market Flaws
Either of two fundamental flaws which prevent the market from sending the correct long-run signals for investment and reliability: (1) the market's inability to sell reliability, (2) the lack of price-response from more than 95% of load.

Nominal Locational ICAP Payment, LP
The payment received from the Locational ICAP by a generator that is available to the exact extent of its bid. This is computed from the Locational ICAP Price as determined by the Locational ICAP Demand Curve, by subtracting the Peak Energy-Market Rents.

NYISO
New York Independent System Operator.

Objective Capability, OC
The minimum acceptable capacity level for reliability

Peak Energy-Market Rents, **PER**
The actual revenues, net of variable costs that the Benchmark Generator would earn for the year in question if it were always available. (See also PVR.)

Peak VOLL Rents (See Average Peak VOLL Energy Rents.)

PJM
PJM Interconnection, L.L.C.

Rents
Revenues minus variable costs.

Short-Run Locational ICAP Price
The same as the Locational ICAP Price, but use when contrasting it with the Long-Run Locational ICAP Price.

Standard Deviation, SD
As used in this testimony, the standard deviation of the historical distribution of capacities relative to OC (presently, 0.058)

Target Capacity Level, C_{Target}
The desired average level of installed capacity initially set at historical average level of capacity relative to Objective Capability.

Value of Lost Load, VOLL

The average value of a MWh of load that is involuntarily shed.

V

Variance.

VC

Variable cost.

W

The sum of W_H over all hours of the year.

W_H

The criticalness weight for hour H, $W_H = 0$ in non-critical hours.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Devon Power Company, LLC, et al.) Docket No. ER03-563-030

AFFIDAVIT OF WITNESS

I, Steven Stoft, being duly sworn, depose and say that the statements contained in the foregoing testimony on behalf of ISO New England Inc. in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this _____ day of August, 2004.

____
Steven Stoft

Subscribed and sworn to before me this _____ day of August, 2004.

____
Notary Public, State of Massachusetts

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