ANALYSIS OF THE JOINT PROPOSAL FOR IN-CITY CAPACITY MITIGATION[1]

The purpose of this paper is to address alleged deficiencies in, and needed reforms to, the New York Independent System Operator, Inc. ("NYISO") in-City capacity market. In particular, it is focused on the joint proposal of The Consolidated Edison Company of New York Inc. ("ConEd") and New York Public Service Commission ("NYPSC") Staff "Proposal for In-City Capacity Mitigation," dated August 9, 2006 ("Joint Proposal"). It also discusses proposed improvements in the market that KeySpan-Ravenswood, LLC ("KeySpan" or "Ravenswood") is willing to support.

THE NEED FOR CAPACITY MARKETS AND NEW YORK HISTORY

In any competitive market, it is necessary that expected revenues be sufficient to maintain the existence of needed and efficient existing supply and cause new supply to be created when such supply is needed. Electricity markets are no different. Some industry experts regard the optimal structure of payments to generators as arising entirely from energy and ancillary services markets – *i.e.*, a market without a separate capacity product as such. While there are sound theoretical arguments in favor of this position, the practical fact is that in order for energy markets to support necessary existing capacity and provide support for new entry, "shortage prices" have to be dramatically high for prolonged periods.[2]

---

1 This paper was commissioned by KeySpan Corporation and prepared by William Hieronymus of CRA International. The views expressed herein are those of the author and do not necessarily reflect those of KeySpan Corporation or Dr. Hieronymus' colleagues at CRA International. Dr. Hieronymus has testified before FERC and other bodies on numerous occasions on market design and market power.

2 See *Prepared Rebuttal Testimony of William H. Hieronymus* in Docket No. EL03-180-000 (Exh. ENR-278, pp. 32-34 and Exh. ENR-280). This testimony demonstrates that prices in the California ISO's energy-only market were insufficient to support needed new entry over the first seven years of its existence. This period includes the "California Crisis" period of May 2000 through May 2001, a period in which prices were regarded as unacceptably high by a very wide margin. In fact, prices during the crisis period have been substantially reduced by *ex post* mitigation, so that revenues actually received over the seven-year period are well short of what would be required to support market entry.

There are two principal difficulties with this approach. First, it supposes that the system will regularly be at or near energy deficiency in real-time operation, notwithstanding that installed capacity well in excess of anticipated energy and operating reserve requirements is mandated in most energy markets. Even if the energy market includes scarcity pricing provisions during reserve scarcity, such as exist in the New York market, such conditions are unlikely to occur naturally in more than a very few, scattered and unpredictable hours. Second, in auction type markets such as exist in NYISO, such prices only can occur if either 1) the system runs out of energy, resulting in prolonged periods where energy is priced at the $1000/MWh bid cap, or 2) a supplier is able to, and does submit very high bids (*i.e.*, many multiples of its variable costs) that are accepted for price formation purposes on a relatively frequent and prolonged basis. As the latter, rightly or not, is generally regarded as the exercise of market power irrespective of the circumstances, and the former is unacceptable from both a price and reliability perspective, most (though not all) of the organized RTO markets have created, or are in the process of creating, capacity markets.

Origins of the NYISO Capacity Market

Prior to market reforms in New York, each control area utility was responsible for meeting New York Power Pool ("NYPP") reliability requirements, largely from its owned resources. The implicit cost of capacity was the full embedded cost of generating resources, less margins received in excess of short-run marginal cost. The explicit cost of capacity was higher still; the "demand-related" cost was the full embedded capital cost and fixed O&M for generation.

When the NYISO was formed broadly coincident with restructuring ownership of generation and implementation of retail access, installed capacity ("ICAP") requirements and markets for three zones were established: Zone J (New York City, or simply "the City"), Zone K (Long Island) and the entire NYISO system. The New York City (*i.e.*, "in-City") zone minimum requirement for LSE purchases from in-City resources was set at 80 percent of peak load, reflecting import limits and N-2 contingency security constraints. This carried forward ConEd's prior practices. The original ICAP provision simply required that all in-City load-serving entities ("LSEs") own or purchase capacity to meet their exact reliability requirements, creating, in effect, a vertical demand curve. That is, the in-City LSEs were required to procure capacity equal to a total of 118 percent of peak load, of which 80 percentage points had to be from in-City resources. There was no value given for additional capacity above the minimum requirement. LSE deficiencies would incur a penalty charge initially set at $150/kW-year. The penalty charge was intended to be set at three times the carrying cost of a new peaking unit, but it was never implemented as such.[3] The theory was that new capacity would be purchased (bilaterally or in spot markets) in order to avoid deficiency payments, so that markets would clear at some price below the deficiency payment level.

The deficiency price was, by design, intended to be well above the cost of entry, and as such, purchases would assure capacity adequacy. However, it turned out that the $150/kW-year in-City deficiency price was only slightly more than the in-City cost of new entry forecasted when the Demand Curve was initially implemented in 2003, as well as the cost of new entry calculated in the Levitan Study. It was never a multiple of the cost of entry.

In the years before implementation of the demand curve in 2003, there were two changes in the ICAP mechanism. First, monthly auctions were added to the six-month strip auctions that existed. Second, the unit of measurement for purchase and sale of capacity was revised from ICAP to Unforced Capacity ("UCAP") in order to better reflect the capacity value of individual resources.

[3] The NYISO penalty charge never amounted to three times the cost of a new in-City peaking unit. In 2003 when the Demand Curve was first implemented the cost of entry for 2003 and 2004 were established at $114/kW-year and $135/kW-year respectively. Based on the Levitan study, as approved by the Commission, in 2005 the carrying cost of a new in-City GT was established as $128/kW-year ($176 - $48). Accordingly, the penalty charge, in each of these years, would have been $342/kW-year, $405/kW-year, and $384/kW-year respectively, if it was set at three times the cost of new entry. Currently the overall Demand Curve price cap for in-City capacity is only 1.5 times the cost of new entry.

ConEd Asset Divestiture and In-City Mitigation

In 1998, by agreement with the NYPSC, ConEd agreed to divest approximately 6,600 MW of its owned in-City capacity. For various reasons, it concluded that the assets should be packaged into four bundles: 1) Ravenswood, 2) the Astoria steam units and the peakers at Gowanus and Narrows, 3) Arthur Kill and the Astoria peakers, and 4) the combined heat and power units that supported its steam system. While the latter was planned for later divestiture, it, along with various contracts with qualifying facilities ("QFs") and the New York Power Authority ("NYPA"), was retained by ConEd. The divested bundles are now owned respectively by Ravenswood, USPowerGen/Astoria and NRG Energy, who are collectively referred to as the Divested Generation Owners ("DGOs").

In May of 1998 ConEd petitioned the Federal Energy Regulatory Commission, (hereafter "FERC" or the "Commission") to pre-approve its proposed mitigation of the pricing of energy, ancillary services and capacity from the units that it proposed to sell. ConEd stated its belief, with which the Commission concurred,[4] that absent such mitigation the purchasers of divested generation could exercise market power in each of these markets subject only to the (then yet to be determined) NYISO's overall price caps. ConEd asked for and received approval of the mitigation proposal, prior to divestiture, so that bidders on the bundles to be divested could have increased certainty with respect to the revenues they reasonably could expect to earn from the divested units.[5] ConEd also entered into transition energy and capacity agreements with some of the divested units for a period of time (*i.e.*, until the NYISO became operational and established its energy and capacity markets). Although the NYISO energy and ancillary services markets commenced operation in November 1999, the capacity market did not go live until May 2000.

---

[4] *Order Accepting Market Power Mitigation Measures, as Modified, for Filing,* September 22, 1998. 84 FERC ¶ 61,287 (1998) ("1998 Order").

[5] Energy-related mitigation under the "ConEd mitigation" has since been supplanted by the application of the day-ahead and real-time AMP mechanism under the NYISO tariff. These mitigation measures are applicable to all supply in New York City, not just the divested units. The capacity-related mitigation was transferred to the NYISO tariff and remains largely unchanged.

The capacity market mitigation for the divested units consisted of a price and bid cap of $105/kW-year. In addition, the capacity could not be sold physically in bilateral transactions, and it was required to be offered for sale in the NYISO capacity auctions. According to ConEd, the $105/kW-year price and bid cap (a dollar amount that the Commission had recently approved as a capacity price cap for NEPOOL) was below the embedded cost of in-City generation included in its tariffs which were based on 1996 costs of service. ConEd and the NYPSC (which also approved these arrangements) sought to balance maximizing the proceeds from sale, in order to reduce the stranded cost of ConEd's overall generation fleet, with preventing excessive on-going market prices. ConEd argued that the size of each of the bundles proposed for divestiture was large enough that, absent such a cap, the in-City price would rise to the default price (expected to be $150/kW-year). It argued, and the Commission agreed, that at least in the short run, the purchasers of generation (*i.e.*, the DGOs) would likely bid and receive capacity prices in the City at the bid and price cap. Because the $105/kW-year was also a price cap, even if the capacity market-clearing price was above $105/kW-year, the DGOs would not benefit from this higher clearing price, since they would have to rebate any excess revenues. The actual capacity price paid by LSEs (after any such rebates) would be the weighted average of market prices and capped prices if the market price was above the cap.

An important expectation at the time that the mitigation was proposed and approved was that the price and bid cap was above the cost of entry. As the Commission wrote:

> ConEd states that, in a competitive market, the effective price cap would be lower than this charge because it would reflect the cost of installing new capacity -- but market forces cannot be relied on until the market becomes mature enough to create incentives for the construction of new generation. ConEd therefore proposes a price cap of $105/kW/year, a figure which ConEd states is slightly below the average embedded cost of the in-city generating units that are being divested. The $105/kW/year figure is slightly lower than the capacity

> deficiency charge assessed by the NYPP (around $150/kW/year), but is also above the estimated cost to construct a new generating unit.[6]

It was also expected that the entry induced by the $105/kW-year price would quickly create a capacity surplus and a reservoir of potential entry at prices below the cap that would make the caps unreachable and irrelevant. For this reason, ConEd proposed that the bid and price caps automatically sunset in March, 2002, three years after the expected date for completing divestiture.[7] Suppliers, LSEs, or the NYPSC could petition the Commission for shortening or lengthening the period of the cap.

The expectation that entry would occur with capacity prices at the cap level proved largely incorrect. The Market Advisor has found in each year for which reports are available that market revenues were insufficient to cover the cost of a new peaking facility in the City. This was not because capacity prices fell materially below the cap, since they generally have been near the cap. Rather, it is because the cost of entry as now estimated by the NYISO -- an estimate largely ratified by market performance -- is well above the cap. In part, this is merely the effect of inflation (and, perhaps, still higher increases in the cost of new capacity), because the cap has remained unchanged in nominal dollars since it was set in 1998 based on 1996 values. It also appears to be the case that the cost of entry simply was underestimated back when the in-City mitigation was designed.

---

[6] *Ibid,* page 7. The Commission went on to express concern that a price cap in excess of the cost of entry could lead to uneconomic new generation and/or building new generation in preference to new transmission that might in fact be a less expensive means of meeting in-City requirements.

[7] Dr. William Hieronymus, ConEd's primary witness supporting the market power mitigation rules, testified:

> Q. If entry is feasible in substantial quantity by 2002, should the bid cap go away at that time, as Con Edison is proposing?
>
> A: Yes. The proposed bid cap is designed to deal with a specific transitional problem, namely the tight market conditions for in-City capacity that are part of the inheritance from the current regulated system. Once market participants have had an opportunity to alleviate that condition, the City capacity market should be similar in all relevant respects to the New York market, for which no transitional mitigation has been proposed.
>
> *Prepared Direct Testimony and Exhibits of William H. Hieronymus,* Docket No. ER98-3160-000, pp. 30-31. The Commission declined to accept the sunset provision.

In retrospect, given that the cost of entry exceeded the price and bid cap for divested generation, it is unsurprising that significant entry did not occur and that much of the entry that did occur was contracted or otherwise supported outside of NYISO markets. Moreover, it had been thought that entrants could demand a price up to the global cap (*i.e.*, initially $150/kW-year for capacity and higher thereafter) and that this would induce entry even if, contrary to expectation, the cost of entry exceeded the cap for divested generation. However, the deficiency price of $150/kW-year exceeded the anticipated cost of new entry only slightly and, even if correct, was not achievable because of the lumpiness of capacity additions relative to load growth.

The expectation that the deficiency mechanism would induce entry in needed amounts was not only incorrect but, with the benefit of hindsight, predictably so. Uncapped entrants could have successfully demanded prices up to the cap only if essentially all of the entrant's capacity was needed. It should be recalled that the owners of divested generation had no incentive or ability to drive capacity prices above their cap because of the price and bid caps. Hence, an entrant (or uncapped owners of new generation collectively) seeking a price in excess of $105/kW-year would be able to sell ICAP only to the extent that its capacity was absolutely needed (*i.e.*, once all DGO capacity was purchased at the cap). If there was any non-trivial excess capacity available in the market after entry, seeking to achieve a price in excess of $105/kW-year would be unprofitable to the entrant.

Consider a hypothetical 150 MW entrant. Suppose that after entry, there is 100 MW of in-City capacity in excess of the 80 percent minimum reliability requirement. Assuming that the owners of divested generation bid all of their capacity at the $105/kW-year cap, if the entrant bid just under the $150/kW-year deficiency payment, the owner of the entrant would earn revenues only on 50 MW of capacity and would receive revenues of only 50,000*$150, or $7.5 million from the capacity market. If it bid just under the $105/kW-year bid and price cap, the entrant could anticipate that the owners of divested generation would maintain their bids at $105, allowing all of the entrant's 150 MW of capacity to clear in the market and giving it revenues of $15.75 million.[8] Hence, it is unsurprising that in the face of slight amounts of merchant entry the price remained pegged at the cap. It similarly is unsurprising that merchant entry was so modest even though near-deficiency conditions were chronic over the period.

In 2002, Ravenswood filed a request with FERC to: 1) remove the price cap on DGO's capacity sales because, among other things, it was discriminatory, and 2) remove the restriction on bilateral sales of capacity by DGOs because it would make for a more robust market and reduce any supply-side market power to the extent transactions occurred. This request was opposed by, *inter alia*, ConEd and the NYPSC. On May 31, 2002 the Commission rejected the request to eliminate the price cap, based primarily on a finding that the in-City market remained very tight and hence that the price cap remained necessary. The request to lift the ban on bilateral sales was also denied, primarily on the basis that it could increase opportunities for gaming.[9] Ravenswood was instructed to return to the NYISO stakeholder process to discuss changes to the capacity market.[10] The Commission

[8] The in-City deficiency price would have become either $342/kW-year, or $405/kW-year without the implementation of the demand curve in May of 2003, representing three (3) times the then estimated cost of entry in 2003 and 2004. Transitional elements of the initial demand curve reduced the maximum price to $171/kW-year and $202.50/kW-year. The 2005 deficiency payment (or price cap) implicit in the in-City demand curve was $192/kW-year based primarily on 1.5 times the Levitan in-City cost of entry estimate. The point being made remains valid nonetheless.

[9] Interestingly, ConEd's testimony opposing removing the ban on bilateral sales of in-City capacity was premised on the assumption that the clearing price in the spot market would exceed the $105/kW-year price and bid cap. In particular, the argument was that in-City LSEs could be induced to buy capacity bilaterally at a price up to the NYISO market-determined price, which in turn would be the weighted average of capped sales from DGOs and uncapped sales by others. It was postulated that as more and more DGO capacity shifted to the bilateral market, the NYISO price would rise toward the uncapped clearing price set by non-DGO sellers. The validity of this argument rests wholly on the assumption that the NYISO market price would be above $105/kW-year as a result of bids from non-DGO competitive sellers. This has tended not to be the case for a number of reasons, including the impact of new capacity purchased outside of the market at prices above the NYISO capacity market price.

[10] Prior to the Joint Proposal, the stakeholder process has been wholly unsupportive of any revisions to DGO mitigation, even the proposal by the NYISO to remove the bilateral contract restriction as part of the Demand Curve Reset, reflecting the load-oriented voting majority in relevant committees.

signaled its inclination to reduce mitigation restrictions only when the in-City capacity market had become less tight.[11]

The In-City Demand Curve

In 2003, responding primarily to the near-total lack of market-based merchant entry of new capacity in New York, particularly in zones J and K, the NYPSC and NYISO proposed to replace the existing fixed capacity requirement and deficiency payment scheme with an administratively-determined demand curve. The primary changes proposed, and accepted by the Commission, were to: 1) tie capacity prices more directly to the cost of new entry, thereby promoting revenue adequacy for new generators, 2) provide greater revenue stability, 3) recognize that reserves in excess of minimum reliability requirements had value, and 4) reduce the incentives for withholding generation. Under the demand curve mechanism, capacity is paid at the rate believed necessary[12] to support new entry when the amount of in-City capacity equals slightly more than the minimum reliability requirement. The price is reduced linearly (at a rate currently of $.0096/kW-month of UCAP[13]) as the quantity of capacity priced under the demand curve increases, reaching a zero price at 118 percent of the in-City minimum reliability requirement. The demand curve price similarly increases above the estimated cost of entry when capacity is below the minimum reliability requirement, up to a maximum of 150 percent of the estimated

11 Ironically, now that the market is less tight, ConEd and the NYPSC are arguing for additional mitigation, not less.

12 Ravenswood argued during the NYISO stakeholder proceedings, to the NYISO Board of Directors and to the Commission that the cost of new entry being proposed was too low because, among other things, it overestimated the net energy and ancillary service revenue offset. The Commission only agreed with Ravenswood's arguments related to ancillary service revenues and reduced the offset proposed by the NYISO to $48/kW-year from $50/kW-year. It was noted that to the extent this offset was too large or too small the Demand Curve would be self correcting in that capacity would withdraw and enter the market until an appropriate equilibrium price was achieved.

13 The implied rate of decline is $.0096/kW-month based on the slope of the Demand Curve between the cost of new entry point and the zero crossing point.

cost of new entry.[14] At this point the Demand Curve becomes horizontal and prices can no longer increase regardless of need.

The demand curve mechanism was a *de novo* innovation to the NYISO market that has since been proposed by both ISO-NE and PJM, albeit with important modifications.[15] In each case, it remains too early to say whether resulting market prices will be adequate to support efficient investment in existing capacity and new capacity to meet reliability requirements. The adequacy of the NYISO in-City demand curve is discussed more fully below.

ROOTS OF THE JOINT PROPOSAL

The Summer 2006 "Issue"

Initially after the inception of the demand curve, capacity in the in-City market remained tight. Then, just prior to the summer of 2006, approximately 1,000 MW was added to in-City capacity. The two units, each about 500 MW, were controlled respectively by ConEd and NYPA, the two legacy retail suppliers in the City. Despite this increase in capacity, prices in all of the in-City auctions[16] remained at about the same level as previously, approximately at the DGO price cap. It was estimated that 802 MW of ICAP (759 MW of UCAP) was offered at or above the clearing prices in the auctions and was not purchased. It also was estimated by

[14] The "estimated cost of new entry" reflects the cost of building and operating new capacity, an offset for net revenues likely to be earned in energy and ancillary services markets, seasonal differences in capacity and a margin to reflect the risk the estimates are in error. Note also that the capping of prices at 1.5 times the cost of entry on the up side and at zero on the downside are asymmetric. For there to be symmetry, the demand curve price cap would have to be 2 times the cost of entry, thereby providing a possible clearing price of twice the cost of entry to average with the possible zero cost clearing point. Nevertheless, this distinction is largely academic, since at such high prices and low levels of capacity, the lights in the City would most likely go out.

[15] ISO-NE initially proposed a LICAP market that included a sloped demand curve, but this proposal has since been replaced by the Forward Capacity Market design that uses forward procurement instead of a sloped demand curve. PJM's filed Reliability Pricing Model (RPM) uses both forward procurement and a sloped demand curve.

[16] These include the voluntary six-month strip auction, the monthly auctions, as well as the obligatory monthly Spot Demand Curve auctions.

NYPSC Staff that had all capacity been offered as price-taking in the demand curve auction, the Demand Curve clearing price would have been reduced to $5.44/kW-month (in May) from the $12.71/kW-month that actually occurred.[17]

Was the Result Unexpected?

The premise underlying a requirement for the existing price and bid caps for DGOs always has been that, in view of the large size of the bundles that were sold, one or each of the DGOs would remain pivotal in the in-City capacity market until there was significant surplus capacity brought on by new entry. It was also believed that if the cost of new entry was below the DGO cap, entry (actual or potential) would discipline prices to the cost of new entry; DGOs would have either to reduce offers or lose their market. However, as discussed above, the cost of new entry is in fact above the price and bid cap. As a result, it became readily anticipated that unless there was quite substantial excess capacity in the in-City capacity market priced below the DGO capacity, prices would remain at or about the DGO bid and price cap level.[18] As stated by the CEO of NYISO in a letter to the Director of the Office of Enforcement,[19] "[t]his outcome is predicable because generating capacity within New York City does not provide a great enough surplus, leaving several suppliers in the position of being 'pivotal' and thus able to maximize profits by bidding enough capacity at the price cap to maintain ICAP prices at that level…. With the recent addition of generating capacity in New York City, it is reasonable to ask whether it was contemplated that prices could stay at the level of the price cap despite the

17 Note that the $12.71/kW-month price is not sustainable under the existing price and bid cap. If bid in each month, it would result in revenues of $152.52/kW-year, substantially more than the DGOs could retain. The NYISO market rules are structured such that the price and bid cap is much lower in the winter months, thereby shaping the price with higher levels in the summer. Accordingly, in-City clearing prices during the six winter months are significantly less than those in the six summer months.

18 Because clearing prices were historically below the actual cost of new entry and on average even less than the DGO price and bid cap, the NYISO's competitive market was unable to induce substantial amounts of market-based merchant supply investment. To this date, the NYISO's competitive market is unable to encourage infrastructure investments without out-of-market bilateral contracts, as confirmed in its recent Comprehensive Reliability Plan.

19 Letter from Mark S. Lynch to Susan Court, Esq., Director, Office of Enforcement dated June 7, 2006, pages 1 and 3.

addition of new capacity. The answer appears to be that such a result was explicitly contemplated. In footnote 17 of its 1998 Order, the Commission said:

> Given the circumstances present here, existing suppliers are likely to bid the price cap and set the market clearing price at that level even as new generation is added and supply increases. This is because, until the supply increases sufficiently to supplant substantial amounts of existing capacity, the existing suppliers will be assured that at least some of their capacity will be selected at any price and so they have an incentive to bid the price cap to maximize revenues of those sales."

Is the Existing Price Unjust or Unreasonable?

In opposing Ravenswood's attempt to remove the DGO price cap in 2002, ConEd argued forcefully that retaining the existing price cap did not deprive the DGOs, or any other party, of "the benefit of the bargain." ConEd argued:

> The existing mitigation measures, approved by this Commission, achieve the intended purposes in a balanced and equitable way. The measures were fair to consumers and to the new purchasers. They assured that electricity consumers were not penalized by accepting the transition to competition – as would result if the formerly regulated generation in the City could force excessive "capacity" prices merely for continuing to be available. In order to encourage expanded supply, new entrants were not subjected to the mitigation measures. Of course, their ICAP prices were ultimately restrained by the deficiency charge. Consumers paid a blended price, which reflected the price cap on existing capacity and the prices received by new entrants. And the prospective new owners were able to take the mitigation measures into account in determining the price they would bid in the divestiture auction and thus could bid knowing the price cap/bid cap would be in place:
>
> > The in-City [ICAP] price cap was imposed prior to the divestiture of generation by ConEd to alert potential purchasers about mitigation measures that could affect their profits. *In other words, the potential purchasers were afforded an opportunity to adjust their bids for the generation being divested by the amount necessary to compensate them for effects of mitigation measures.*

> This arrangement has worked well. Substantial new capacity additions are planned in the City. Consumers pay capacity payments consistent with the value of the auctioned assets and the DGOs receive precisely what they bargained for.[20]

On this basis, it cannot be concluded that actual prices in the summer of 2006 were unjust and unreasonable, or that a change in the demand curve mechanism as contemplated in the Joint Proposal is necessary to avoid purported unjust and unreasonable prices.

Is the Existing In-City Capacity Market Clearing Price Excessive?

The purpose of the NYISO capacity market, both before and after the demand curve innovation, has been to provide sufficient payment to generation that, taking into account margins earned in energy and ancillary services markets, needed investments in existing and new capacity resources would be made and result in sufficient capacity to achieve desired levels of reliability. In relationship to that standard, we consider two market outcomes. In the first, the demand curve operates as ConEd and the NYPSC Staff believe it ought, with all capacity bid in at mitigated reference prices that are well below the demand curve. In the second, it is assumed that the DGOs can (and are permitted to) offer their capacity at the Commission-approved price and bid cap of $105/kW-year in nominal terms (assumed to diminish in real terms by 3 percent per annum inflation).[21]

Table 1 shows capacity prices under both scenarios. Because of winter unit ratings and the fact that the resultant winter capacity quantities are currently approximately 800 MW higher than summer quantities due to temperature differences, the winter

---

20 *Motion to Intervene and Protest of Consolidated Edison Company of New York, Inc.*, Docket No. EL02-59-000, quoting from *New York Independent System Operator, Inc.*, 96 FERC at 61,994 (emphasis added by ConEd).

21 The decline of the real dollar equivalent of the fixed $112.95/kW-year (UCAP) price ceiling for DGO generation from 2006 to 2011 in the calculation illustrates that the ceiling generally is of wasting relevance. At the time it was instituted it was, in today's money, approximately $139/kW-year. Because the components of new generation cost (*e.g.*, construction and other labor, property taxes and so forth) actually have risen faster than inflation, the ratio between the price cap and the cost of entry has eroded still faster.

capacity demand curve price is consistently lower than the summer price. It is assumed that capacity requirements grow by 170 MW per annum (approximately 1.6 percent load growth of which 80% is required in-City, or 136 MW, which is approximately 129 MW UCAP) and that new capacity is built in the exact amounts required to maintain minimum reliability requirements implicitly adding enough to cover any capacity retirements, such as the planned retirement of Poletti and the 79.9 MW simple cycle facility in Vernon, over the next 5 years. Results are stated in real (inflation adjusted) terms.

Table 1

Year	Summer ($/kW-month) (UCAP)	Winter ($/kW-month) (UCAP)	Scenario #1 Annual $ Joint Proposal	Scenario #2 Annual $ Existing Mitigation	Capacity Surplus Summer (MW)	DGO Cap Price (UCAP)
2006	5.25	0.00	31.30	111.30	1037	111.30
2007	6.93	0.00	41.58	107.96	833	107.96
2008	8.64	0.00	51.84	104.72	704	104.72
2009	10.37	1.42	70.74	101.58	576	101.58
2010	16.83	7.73	147.36	147.36	0	98.53
2011	17.25	8.04	151.74	151.74	0	95.58
Average			82.46	120.78		

To illustrate how the Joint Proposal (Scenario #1) would work, if all capacity is offered into the market at below the demand curve price (*i.e.*, if all suppliers act essentially as price takers), the simple average price during this six-year period will be $82.46/kW-year (all amounts are expressed in UCAP terms). This is well below the NYISO’s estimate of the capacity payment necessary to support entry. If DGOs offer their capacity in accordance with the Commission-approved price and bid cap and set the price until the naturally occurring price exceeds the DGO cap (Scenario #2), the average capacity revenue is $120.78/kW-year. This still is below, but materially closer to, the net capacity revenue requirement for entrants. Of course, on a present value as opposed to simple average basis, the results are still less attractive for capacity resources, particularly under the Joint Proposal, since the very low prices occur in the earlier years. In contrast to the prices earned by unmitigated resources, the DGOs would receive the lower of their price cap or the market price. This averages only $64.96/kW-year under Scenario #1 compared to $103.28/kW-year under Scenario #2.

It could be argued that these calculations that show severe revenue inadequacy under the Joint Proposal are a result of the excess capacity arising from the units commissioned by ConEd and NYPA that came on line earlier this year. Certainly it is the case that the demand curve could in principle support resource adequacy; that is what it was designed to do. However, even the existing market design (*i.e.*, without the changes contained in the Joint Proposal) would only support new capacity when needed if: i) annual capacity additions are quite small and timed precisely to match load growth, and ii) the system is capacity deficient as often as it is in surplus (with excesses and deficiencies of equal magnitude).[22] In Table 1, these conditions could occur in 2010-2011 if NYPA retires its Poletti facility with only off-setting in-City capacity supply or demand bid additions. Regardless, whether the market is short or just meets minimum reliability requirements, these are years in which the DGO price cap is irrelevant in setting the market price. However, it cannot reasonably be expected that conditions shown in those years will be typical and, in any event, even if market equilibrium is maintained from 2010 onward, this will not make up for revenue inadequacy in the earlier years.

A more likely outcome, resulting in still less adequate revenues under the Joint Proposal, is that in the future additional new supplies will be procured out-of-market and large LSEs and/or government entities will maintain capacity amounts in excess of minimum requirements, thereby maintaining capacity prices at lower levels than posited in Table 1. Table 2 reproduces Table 1, except that there is 1000 MW of capacity purchased out-of-market in 2010 (much of which covers the Poletti retirement, also assumed in that year) and scheduled into the capacity market, and a further 500 MW added in 2011.

[22] Since the current surplus over the target reserve is over 1,000 MW, this requirement for symmetry cannot in fact be met. If the in-City capacity market was ever over 1,000 MW short of minimum reliability requirements, blackouts would most likely occur, and prices would nonetheless be capped at 1.5 times the cost of entry, thereby failing to average at the cost of entry.

Table 2

Year	Summer ($/kW-month) (UCAP)	Winter ($/kW-month) (UCAP)	Scenario #1 Annual $ Joint Proposal	Scenario #2 Annual $ Existing Mitigation	Capacity Surplus Summer (MW)	DGO Cap Price (UCAP)
2006	5.25	0.00	31.50	111.30	1037	111.30
2007	6.93	0.00	41.58	107.96	833	107.96
2008	8.64	0.00	51.84	104.72	704	104.72
2009	10.37	1.42	70.74	101.58	576	101.58
2010	11.59	1.27	77.16	98.53	521	98.53
2011	8.52	0.00	51.12	95.58	857	95.58
Average			53.99	103.28		

Under these circumstances of future out-of-market purchases, the average price under the Joint Proposal falls from $82.46/kW-year if no further out-of-market purchases that cause cqpacity to exceed the reliability minimum occur (*i.e.*, the Table 1 prices) to $53.99/kW-year. Revenues earned by the DGOs under the lesser-of-cap-or-market provision of the Joint Proposal decline from $64.96/kW-year to $53.99/kW-year.

Several conclusions can be drawn from this example:

- DGOs continuing to offer in accordance with the Commission-approved bid and price caps in years of significant surplus does not result in a pattern of bids or prices that exceed the cost of new entry, even taking into account the effect of shortage years.
- Such prices may be necessary under the existing demand curve structure if market prices over time are to approach the cost of new entry.
- Under theoretical circumstances where the demand curve can support entry (*i.e.*, as assumed in Table 1 for 2010-2011), capacity supply and demand conditions likely will be such that the DGO price and bid cap is irrelevant.
- The 1,000 MW of new entry this year is uneconomic, certainly without the effects of the price and bid caps, and likely even if they remain in place, when its costs are compared to market prices. However, the substantial reduction in

market prices, particularly under the Joint Proposal, may explain why excess capacity is deemed to be highly beneficial to some interests.

- Additional out-of-market purchases in the future will, under the Joint Proposal, continuously keep the market price for capacity well below the value necessary to support new market entry. As discussed above, there is reason to anticipate that such out-of-market procurement of new capacity ahead of and in excess of minimum reliability requirements indeed will occur.

Is a Change in Market Rules Required by Changed Circumstance?

In the presentation of the Joint Proposal, the ostensible motivation for changing market rules is the advent of the demand curve. This is asserted to have two effects. First, under the demand curve the amount of in-City capacity an in-City LSE must buy may exceed the minimum reliability requirement that existed previously. Second, since the statewide market encompasses Zones J and K, and is not just a rest-of-state market, prices paid in the all-of-New York market are affected by the quantity of capacity purchased in the City and on Long Island. Neither of these effects are legitimate motivations for implementing additional mitigation.

With regard to the former, it is correct that if the market clears at the DGO's price cap, that in-City LSEs will have to purchase quantities of capacity greater than the minimum reliability requirement. However, this change is relatively trivial and entirely expected under the demand curve design. The implementation of the demand curve explicitly valued capacity in excess of the minimum requirements. According to presentations made at the NYISO ICAP working group meetings, at the DGO price and bid cap in-City LSEs have to procure an additional 2.9 percent of capacity relative to the minimum reliability requirement. This amount is less than 300 MW or $3 million/month and is implicitly contemplated as a clearing point on the demand curve. This additional expenditure and capacity provides both improved reliability and energy pricing, as noted in the NYISO's original demand curve filing.

With regard to the second issue, if this is regarded as problematic, a minor change in the structure of the demand curve mechanism could eliminate it. The pre-demand curve market allowed locational capacity (*i.e.*, Zone J and K capacity) that was not sold or required to meet minimum reliability requirements to be sold in the statewide auctions. To the extent such capacity was offered in the statewide market at prices less than other offers, it would potentially displace higher priced statewide capacity. However, it is unlikely that in-City capacity would be priced less than statewide capacity, and accordingly past markets rarely had in-City excess capacity effect statewide auctions. The same is true today unless unsold in-City capacity is offered below the statewide capacity clearing price.

However, under the current demand curve rules, capacity offered but not accepted in Zones J and K is not made available in the statewide auction at any price. It would not be inconsistent with the intent of the existing market design if unsold in-City capacity could be offered to the statewide auction after it was determined it was not required to meet minimum in-City reliability requirements. This would require in-City auctions to be conducted prior to the statewide auctions, a difference of no great significance

Presumably, the reason that the larger market is statewide rather than a rest-of-state market is to reflect that if additional capacity (beyond bare-bones requirements) is available in Zones J and K, such capacity could be called upon in periods of severe energy shortage. This would reduce imports into Zones J and K from the rest of New York below levels contemplated in setting the 80 percent and 99 percent requirements for these two zones, and, in turn, allow more energy to be retained outside of the two zones to meet rest-of-state loads. While this is a true statement about system operation, it is not really relevant to capacity price formation. If capacity prices are higher in Zones J and K than in the rest of the state, as always has been true historically and is likely to remain true in the future, then price formation in the rest-of-state capacity market should always be independent of the surplus, or lack thereof, of capacity resources in Zones J and K. That is, so long as prices are higher in Zones J and K, LSEs will buy the maximum amount of capacity that rules allow from the rest-of-state/all-New York market. For this reason, it would be sensible if the statewide market were defined as a rest-of-state rather than an all-New York market.

If this were done, capacity prices paid outside of Zones J and K would be independent of capacity balances in the locational zones, and unaffected by the bids of DGOs in the City.

CRITIQUE OF THE JOINT CONED AND NYPSC STAFF PROPOSAL

The Joint Proposal for In-City Capacity Mitigation specifies conduct and impact tests that, if failed, would cause generators failing them to have their bids replaced by generator-specific reference prices. In order to judge the likelihood of failure and the consequences for market prices, it is first necessary to consider the proposed reference price calculus.

The Joint Proposal is quite short on detail. The description states simply that reference prices "reflect avoidable costs net of energy and ancillary services revenues appropriate for the Demand Curve monthly spot auction." In addition, reference to a PJM document is offered for what allowed costs could be. The document, Attachment Y to the PJM RPM filing includes the usual categories of "going forward" costs: fixed operation and maintenance expense, associated overheads and property taxes.[23]

Such "going forward" costs typically are estimated to be in the range of $15-$35/kW-year, though higher property taxes and other costs may make them somewhat higher in the City. For example, the NYISO's independent study (the "Levitan Study") of the cost of new entry ("CONE") estimates in-City fixed non-capital costs at $38.85/kW.[24] Costs for other units can be more or less; typically they are higher for steam units than peakers.

[23] There is something of a disconnect between the description in the Joint Proposal citing costs appropriate for a monthly spot auction and the PJM cost categories, since some of the latter are avoidable in the event of permanent shutdown. For present purposes, we assume the latter, more expansive, definition.

[24] *Independent Study to Establish the Parameters of the ICAP Demand Curve for the New York Independent System Operator*, Levitan Associates, August 16, 2004 (the "Levitan Study").

From such costs the Joint Proposal would deduct energy and ancillary services revenues (presumably, net of variable costs). The Levitan Study relied on by the NYISO estimates such revenues at $48/kW-year. Hence, we have the somewhat startling result that the Joint Proposal's mitigation reference price for the hypothetical new unit that sets the demand curve reference price would be negative. This result is not as surprising as it might seem at first blush. Particularly in high energy cost regions, such as the City, it is quite common for the energy revenues of an efficient unit to approach or exceed going forward non-capital fixed costs. For the substantial majority of capacity in New York City, the netting of energy and ancillary services market revenues against fixed going forward out of pocket, non-capital costs will result in very low, often negative, mitigation reference prices.[25]

The result that mitigation reference prices will be zero or very low has significant consequences for the conduct and impact tests. Adding a percentage to zero provides no conduct threshold. The conduct test is that the bid exceeds the reference price by 3 percent. Given that reference prices will be very low or possibly even zero, any significantly positive bid will fail this test. The impact test similarly compares prices under reference prices to prices based on actual bids. Clearly, if the DGOs (or other generators) have very low reference prices and bid anywhere near the cap (or even in a manner intended to meet debt service requirements), they will fail both the conduct and the impact test. To a first approximation, given that essentially all capacity will have low net reference prices, the only circumstance in which the impact test will be passed is if all bids are low enough that the bid supply curve crosses the capacity demand curve where the supply curve turns vertical. This is the point where all capacity has been bid into the market at bids below the demand curve and the supply

[25] The Joint Proposal would initially replace reference prices with interim prices based in part on statewide capacity prices. The interim prices are not addressed in this paper, although those prices are purported to be even lower than the reference prices described above. Regardless of the level of the interim prices, it is difficult to see how prices unrelated to the actual cost of capacity in Zones J and K could be justified as substitutes for reference prices. Moreover, the interim proposal ignores the relative differences in the tightness of the in-City and statewide markets since, by setting the in-City price at the statewide price times the ratio of the costs of new entry, the implicit assumption is made that the two markets are at the same point on their respective demand curves.

curve turns vertical because there is no more supply available.[26] This result, where all capacity might as well be offered at zero since the price is set solely by the demand curve, likely is the intended result of the Joint Proposal.

Notably, the Joint Proposal appears to apply to all capacity, not just DGO capacity. Hence, the proposal not only would force DGOs to bid at prices well below their currently-approved price and bid caps, but also would force all other capacity resources in the City to bid below levels required to meet debt service and equity returns. Presently, there is no mitigation of bids for such capacity resources (including presumably demand response resources and on-site "special case resource" generation).

The final feature of the Joint Proposal is that existing DGO mitigation measures would also remain in place. These mitigation measures, specifically the price caps, it should be recalled, were put in place to remove the incentive for DGOs to raise clearing prices above the cap through economic or physical withholding. Given that the operation of the Joint Proposal would effectively preclude bids above the demand curve, and hence any meaningful "economic withholding", and that physical withholding is not allowed, there is no logic for maintaining most of the existing restrictions. Only the obligation to offer capacity to the market, if not previously sold in a bilateral agreement, needs to be retained. As shown in the previous calculation, there may be times when the naturally occurring competitive price under the demand curve is above the price cap. Moreover, if the Demand Curve is to serve its intended function, clearing prices above the price cap and the cost of new entry must occur to offset clearing prices below these levels. This is the only way the appropriate equilibrium will be established. According to the existing Demand Curve, clearing prices in excess of the price cap occurs whenever the capacity excess is less than 2.9

[26] The NYPSC study indicates that if all the existing capacity supply was offered at prices below the demand curve, the summer strip price would be $5.44/kW-month. Based on the estimate that winter capacity is approximately 800 MW higher, the price is $-3.43/kW-month or $0/kW-month. This yields annual capacity revenues of approximately $36/kW-year. This is likely in excess of the reference price for all but a very few supplies. Even these supplies could be kept from bidding above the demand curve price (thus removing them from the capacity market) if they have above-market contracts with an entity that schedules them into the capacity market.

percent or approximately 300 MW. Creating a dual market, where DGOs get a capped price and all others get the market price, surely is unwarranted when the market is in naturally tight supply under the demand curve.

Question: Where Does New Capacity Come From? Answer: Monopsony Purchases

The foregoing demonstrates that under the Joint Proposal, the new capacity that came on line this year would be predictably unprofitable if paid only market prices. Even under the existing market design, it still likely would be unprofitable without higher out-of-market payments. Why then does it exist?

The answer is that it was not built in anticipation of receiving market prices. It was built by one of the legacy utilities, *i.e.*, NYPA, or underwritten by a long-term purchase contract with ConEd. Since the cost of new entry is above the market price (and still more above the market price if the Joint Proposal becomes effective), why would ConEd and NYPA incur the costs of new entry? Even assuming a net capacity cost of, for example, $125/kW-year, it still would be cheaper to buy capacity at the DGO cap price.

The answer lies in the exercise of monopsony power. Monopsony is buyers' market power and operates in a manner similar to monopoly or sellers' market power. There are, however, significant differences. In particular, monopoly power generally is exercised by withholding supply. Retail utilities cannot withhold demand, particularly capacity demand, since (at least historically) they are required passively to meet customers' loads. While this is less true today, it still is true of ConEd and NYPA as providers of last resort ("POLR").[27] Monopsony power requires a more refined strategy than withholding; the primary means of exercising monopsony power in capacity markets is price discrimination.

[27] NYPA is not technically a POLR in the City. However, it has long-standing contract loads that it customarily has served. Much of that load is served under contracts and tariffs that allow the pass-through of as-incurred costs.

So as not to impugn the motives of any particular participant in the NYISO market, we will refer to the monopsonist as Buyer A.[28] A necessary hallmark of buyer A is that it is a relatively large market participant, as also would be true for an effective monopolist. Buyer A is facing a demand curve that slopes downward quickly as additional capacity is built. Approximately 1,000 MW of capacity in excess of the minimum reliability requirement is sufficient to reduce the price under the demand curve by approximately $9.60/kW-month. Suppose that Buyer A has a load of 6,000 MW. With zero surplus (*i.e.*, with exactly the minimum reliability requirement met) its cost of capacity is $91 million/kW-month, using the current $15.15/kW-month demand curve cost of entry price. If it contracts with a new 1,000 MW generator, it can reduce the price it pays for its remaining 5,000 MW of market purchases by $48 million. In turn it has to pay the costs of the new generator, but so long as the new generator's cost is not significantly above the demand curve cost-of-new-entry price, the $48 million is a net cost savings. Hence, by entering into the contract, it can cut the price paid to all existing generators by nearly two-thirds and reduce its costs by more than half.[29]

Put another way, the savings that Buyer A achieves are $4.80/kW-month for every kW that it causes to come into the market. This is $57.60 per kW-year. Therefore, even if it were necessary to pay more than the reference price, it still would substantially reduce its cost. Note also that, given the steepness of the demand curve, this result does not depend on the purchase being a large one. If a new plant of 150 MW is caused to enter the market, the savings is $1.44/kW-month for every

---

[28] It is recognized that ConEd and NYPA have a variety of motives for building or contracting for new capacity outside of the capacity market. For example, the new combined cycle unit at Poletti is intended ultimately to allow closure of an existing unit, resulting in environmental benefits. The effect of out-of-market purchases on the capacity market and the viability of merchant entrants into the NYISO market more generally does not depend on the motives of the buyer of such capacity, but merely on the existence of the practice.

[29] Existing and proposed market mechanisms in ISO-NE and PJM recognize the possibility of this type of monopsony behavior and include provisions designed to temper its adverse effects on markets. No such provisions are included in the Joint Proposal and, indeed, at the Business Issues Committee meeting at which the Joint Proposal was approved, a proposal based on these tempering provisions was rejected with the balance of voting mirroring the votes on the Joint Proposal.

remaining kW purchased from the market. Since with a smaller out-of-market purchase the number of MW remaining to be bought from the market is larger, the "bang for the buck" is larger still, $67.39/kW-year for every MW induced to enter.

Note that this strategy only reduces prices if the contracted capacity is from new entrants. A non-monopsony buyer would be indifferent between buying from new or existing capacity: its only motives would be cost and risk minimization. Only a buyer with monopsonistic intentions would restrict such purchases to new generation.

In this context, it is instructive that ConEd would not permit any existing resources (including DGO resources) to participate in their request for proposal ("RFP") considered in NYPSC Case 02-E-1656. Moreover, Ravenswood was not permitted to bid the 250 MW of new merchant capacity that it was in the process of developing, even though that capacity did not yet exist.

Not all LSEs can employ this strategy. The limit on the strategy arises from the fact that the reduced market price is available to all LSEs, not just Buyer A. To revert to the 1,000 MW example, if Buyer A pays the cost of entry price of $15.15/kW-month for 1,000 MW of contracted or purchased generation, its cost of capacity under the Joint Proposal will be (1,000*$15.15 + 5,000*$5.55)/6000 = $7.15/kW-month, whereas its competitors buying all of their generation at the market price will pay only $5.55/kW-month. Setting aside issues of hedging positions and other transitory phenomena, if retailing is a competitive market, Buyer A will have to deduct the extra costs from profits, since competing offers generally will reflect the lower cost of market purchases.

Hence, in the presence of retail competition, the monopsony strategy only will work for capacity buyers who can pass through the higher cost of out-of-market purchases. The legacy utilities who are providers of last resort are the only buyers capable of doing so. Since POLR sellers pass through their cost of purchases at actual cost, rather than market prices, the $7.15/kW-month purchase price can be passed through in POLR rates.[30] The only limit on this strategy is that there may be a greater take up of competitive offers if POLR rates increase. To the extent that: 1) POLR rates include legacy costs that are below market (*e.g.*, from retained contracts or generation) such that POLR rates remain competitive, and/or 2) the savings margin required to induce customers to switch out of POLR service is below the cost disadvantage arising from the monopsony strategy, there is no effective barrier to it.

Note also that POLR suppliers potentially can insulate themselves from load loss arising from higher out-of-market purchase costs by seemingly benign changes in market rules. Southern California Edison ("SCE"), which also is buying new generation bilaterally, has gained the right to pass out-of-market costs through to other retail suppliers in its area. The result is that it will suffer no competitive disadvantage; its costs and all of its competitors' costs will go up identically as a result of purchases and down identically as a result of suppressing the market price. While this is not a feature of the Joint Proposal, it is not difficult to foresee that if the monopsony strategy erodes POLR load sufficiently to jeopardize the ability to sign further out-of-market contracts, it would be introduced. Proponents of a requirement to spread such costs to all LSEs would argue that it was necessary by pointing to the fact that no new merchant generation lacking out-of-market contracts was being built (since market prices are too low) and hence, the only way to keep the lights on is for the POLRs to be able to continue to make out-of-market purchases. Such an argument could well be persuasive *at that time*.

Implications of the Joint Proposal

The direct and intended effect of the Joint Proposal is to reduce the market price paid for capacity. This, presumably, is why the NYPSC Staff supports it, notwithstanding that the implication that new capacity, built only if contracted to ConEd and NYPA,

[30] Since this is a pure pass-through, the POLR providers do not benefit directly from price manipulation, in that it does not increase their profits. However, POLRs are vulnerable to political and regulatory pressures, and measures taken to reduce prices, even if profit-neutral directly, can improve their economic performance indirectly. Moreover, to the extent that lower prices increase load, there is a direct profit benefit under fixed distribution tariffs. In addition, to the extent the POLR has an affiliate that participates in the retail access market, the POLR's profits can be increased indirectly via the cost savings to the affiliate resulting from the depressed market prices.

subverts the NYPSC market reforms and policies that caused the New York utilities to divest most of their capacity in the first place. What offsetting disadvantages arise from adoption of the Joint Proposal?

Implications for Markets

The first implication is that the legacy POLR providers will have an incentive to create excess generating capacity. Ironically, when the Commission approved the existing 1998 ICAP mitigation proposal containing the DGO price and bid caps and other mitigation measures, it was concerned that a bid and price cap above the expected cost of entry would result in uneconomic amounts of new generation:

> … if the price cap is increased to ensure adequate incentives to construct new generation, the price cap will not only increase the cost of power, but may well induce more construction than necessary. [Footnote omitted]. Moreover, it may create a bias for the construction of additional generation when transmission expansion is the less expensive and more efficient method of accessing additional generation capacity.[31]

The Commission's concern was that if the DGOs offered their capacity at the cap (as it predicted in the omitted footnote that they would), excessive merchant entry would occur. Here, the effect of the Joint Proposal is to create an incentive for a POLR to create unnecessary generation outside of the market, since, if it is implemented, additional capacity will linearly reduce market capacity prices. Note that the additional capacity occasioned by the 1,000 MW of new generation underwritten by the legacy utilities that came on line this year results in capacity in the City of approximately 11.5 percent above minimum reliability requirements.

A second effect, demonstrated above, is to hold capacity market prices well below the cost necessary to support resource adequacy, destroying the intended effect of the demand curve (and capacity markets more generally) to create market revenues adequate to the purpose. If POLR providers (or any other entity) continue to create significant amounts of capacity in advance of when it is required by the minimum reliability standard in order to hold down capacity market prices, the only source of

[31] 84 FERC ¶ 61,287 at 62,357 (1998).

new capacity will be built by, or contracted for under long term PPAs with, such entities. This is contrary to the intended nature of the NYISO, NYPSC market reform policies, and Commission policy more generally. The end result would be "back to the future" with all new capacity built for or by the dominant utilities. It would, in effect, return the market to a cost-of-service structure, albeit one unit at a time.

A third market effect is to create a two-tiered capacity market. Generation holding PPAs with POLR providers will receive one price and all other market participants another (lower) price. Such two-tiered markets, in which different sellers receive different prices for functionally identical products, is inconsistent with the workings of a competitive market. As Dr. William H. Hieronymus, ConEd's primary witness on the original ConEd market mitigation explained in the context of supporting uniform bid caps for divested generation:

> Q. Please explain why a uniform bid cap is consistent with the objective of transition to a competitive market and a unit-specific embedded cost bid cap would interfere with that process.
>
> A. Under the rules of the proposed New York market, the economic value of each megawatt of capacity for each of the divested units is identical. Without specific mitigation, each unit would receive the same capacity price. This characteristic of competitive markets, the "law of a single price" under which the price received for a unit of output is independent of its specific cost of production, is a key feature that differentiates competitive markets from traditional cost of service markets…
>
> Q. But won't a uniform below-average bid cap result in "above-cost" revenue for some units during a period when there is a potential market power?
>
> A. Yes. However, the divorcement of costs and revenues is the desired consequence of competitive markets. Further, the Commission's historic opposition to "above cost" pricing was intended to protect consumers from paying higher prices. Under the proposed mitigation, the "above cost' pricing for units with low embedded cost will be precisely offset by "below cost" pricing for other divested units. Thus, consumers would be fully protected. Further the purchasers of units with low embedded costs are not likely to make windfall gains since

> the expected capacity market revenues will be factored into the purchase price.

The Commission has concluded similarly that two-tiered prices are improper, in a more immediately relevant context – its approval of the existing demand curve. NYC and Morgan Stanley, intervenors in the demand curve proceeding, argued that the demand curve would improperly raise revenues for existing generators and that a preferable system would target only new generators. This is precisely the effect that the POLR's targeted inducements restricted to new generation would achieve, if combined with the effect of the Joint Proposal. The Commission wrote:

> 81. With regard to NYC and Morgan Stanley's contention that the proposed ICAP Demand Curve is a blunt instrument that fails to distinguish between old and new generation, the Commission finds that all capacity suppliers, regardless of the age of their resources, are entitled to the same treatment in the ICAP market. While the Commission understands that certain generators may realize greater profits than others, that is simply a fact of the marketplace. The Commission does not see how such generators could receive ICAP revenues that were fundamentally different from those paid to other generators. Moreover those are the types of market signals the Commission would expect to encourage new generation additions.[32]

A fourth effect on the market is to under-price capacity to retailers and hence to end users. This will result in uneconomic levels of consumption and still moreso, sub-optimal signals for demand response.

A fifth effect is that the exercise of monopsony power requires investment in capacity in excess of required reserves, potentially by significant amounts. The cost of such capacity is an inefficient use of society's resources.

Implications for Existing Generators

As described above, a POLR or other actor with similar motives can suppress market capacity prices to well below the cost of entry by a strategy of out-of-market purchases that maintain modest or even large amounts of capacity in excess of the minimum reliability requirement. Under the existing demand curve and market,

[32] 103 FERC ¶ 61,201 at paragraph 81.

monopsony purchasers are not subject to any defined mitigation measures. Monopsony power is to a limited extent controlled by the Commission-approved cost based price and bid caps, which are to be supplanted by the Joint Proposal. The DGOs can to a degree countervail monopsony power by bidding at the Commission-approved cost-based bid cap. As noted previously, the fact that the bid and price cap is fixed in nominal terms means that the price anticipated if such bids are made is a diminishing fraction of the cost of entry, and hence is of diminishing capability to at least partially protect revenue adequacy. Nevertheless, if the ability to bid the cap is maintained, only by creating truly excessive amounts of capacity via out-of-market purchases can a buyer cause prices to fall below the diminishing bid and price cap level.

Under the Joint Proposal, all generators, not merely the DGOs, would be required to bid at prices that are below the demand curve. The result will be that prices will remain significantly below the cost of entry. This applies equally to DGOs, demand response, special case resources and to the relatively small amount of at-risk market entry that has occurred.

The effect on generator enterprise economics would be very substantial, as no doubt is intended. The DGOs would be denied the "benefit of the bargain" entered into when they purchased ConEd's generation. They and other market generators would suffer a severe erosion of revenues. Since capacity is the primary source of contribution to fixed costs for many generators, their financial viability could well be eliminated. Certainly, the reduced revenues will directly impair the ability and willingness of the DGOs and others to invest new capital in existing units to improve their reliability, efficiency and environmental performance.

Lower capacity prices also could lead to the uneconomic exit of existing capacity. While bankruptcy itself may not eliminate capacity that remains viable at the prices that would exist under the Joint Proposal, at least some capacity that is presently economic likely would cease to be so, particularly if maintenance and capital improvements that would have been cost-effective at prices closer to the cost of entry become uneconomic.

Conclusion

The current NYISO in-City demand curve is at best marginally sufficient to support market entry. The ability of the DGOs subject to Commission-approved price and bid caps to bid their capacity at the bid cap is one element supporting the sufficiency of market prices, particularly when substantial capacity in excess of reliability requirements has been built.

The Joint Proposal would have the effect of ratifying the building of significant excess capacity through out-of-market, higher-than-market contracts that, but for continued bids by the DGOs at Commission-approved bid caps, would crater capacity prices. When viewed as a strategy, the building of capacity ahead of need and well in excess of reliability requirements, when coupled with the effects of the Joint Proposal, would wholly subvert the efficacy of the demand curve and of NYISO markets more generally to support needed capacity in the City. The inevitable consequence is a return to a system where all capacity is built by or for the traditional incumbent utility, not by market participants for the competitive market.

The Joint Proposal is not warranted or required by any changed circumstance. The complained-of prices are no higher than previously and remain consistent with the prices contemplated by the Commission, ConEd, the NYPSC and the DGOs when the NYISO market began and when the demand curve was implemented. Those prices are likely to have been anticipated by other market entrants, and are consistent with the mitigation terms on which DGOs relied when purchasing their capacity from ConEd. No case is even attempted to be made by the proponents of the Joint Proposal that such prices suddenly are unjust and unreasonable.

If the Joint Proposal is adopted, having built capacity ahead of and in excess of need, both in the recent past and prospectively, will indeed lower prices to in-City LSEs who have not hedged their requirements,[33] and presumably end use customers, in the near term. It will not do so as a result of greater efficiency, but rather by trapping or stranding costs at existing generators who rely on the market, both the DGOs and other market entrants. In so doing, it will destroy the competitive generation market, create a two-tiered discriminatory pricing system, result in inefficient prices to consumers and substantial financial harm to generators who either bought existing generation or built new generation without the expectation that monopsony power would be exercised and made successful by regulatory changes as are embodied in the Joint Proposal. Moreover, in the long run, this outcome cannot save consumers money, since they will be paying the full cost of new entry (ultimately, all capacity) under out-of-market contracts, and they once again will bear the risks of poor investment decisions, cost overruns, excess capacity and, more generally, the lack of cost discipline that in a properly-designed competitive market are borne by competitive market suppliers.

KEYSPAN'S PROPOSED CHANGES IN THE NYISO CAPACITY MARKET

The Joint ConEd/DPS Proposal seeks to eliminate the ability and incentive for DGOs to offer their capacity at or near the FERC approved price and bid caps, thereby setting the in-City demand curve clearing price at or near the cap, when a lower price offer would result in more capacity being sold at a lower price based on the demand curve.

The preceding discussion establishes that:

1) the purpose of the demand curve is to establish a single price for capacity that will be adequate to provide support for the maintenance of existing capacity and investment in needed entry;

[33] It will raise costs to those LSEs who are fully hedged since the lower prices under the Joint Proposal will require the purchase of additional capacity.

2) as currently formulated the demand curve will not achieve these objectives, since revenue support for new entry will be adequate only under a narrow and likely uneconomical set of conditions;

3) during periods of market tightness there will not be one, but multiple prices, since DGO payments will be below the competitive market price;

4) the DGO offering behavior at issue facilitates rather than subverts the intended purposes of the demand curve, because without it revenue inadequacy would be greater;

5) the existing capacity market gives large in-City LSEs and others with an interest in reducing prices a strong incentive to buy capacity at above-market prices outside of the NYISO markets in order to drive down prices in the market where all of the DGO capacity is forced to transact; and,

6) The RTOs bordering New York are establishing forward markets for capacity. New York needs to craft a forward capacity market. Such a market needs to be sufficiently forward to allow new entry of the types of resources needed for meeting reliability economically, and that the long-term market be backed by shorter term balancing markets, particularly in view of the existence of retail access and demand response in New York.

The preceding discussion also demonstrates that if the Joint Proposal is adopted, the adequacy of capacity market revenues will worsen with the result that no capacity will be built in response to market signals. New capacity will become available only under out-of-market bilateral contracts. As capacity buyers reduce market prices by purchasing new capacity outside of the market and by procuring the remainder in the market at the lower prices determined by the mitigated supply stack, the end result will be the destruction of the competitive capacity market and, indeed, competitive power markets in the City more generally.

KeySpan is proposing a package of both short term and long term measures to improve the existing in-City capacity market. While some of these proposals, particularly those dealing with long-term solutions may be applicable to New York markets more generally, the focus is on the in-City market.

SHORT TERM MEASURES

Lengthen the Demand Curve

The slope of the in-City demand curve is not based on any reliability or economic criteria but is essentially an arbitrary outcome of negotiation. Its steepness makes the in-City demand curve inadequate to support needed economic entry without reducing capacity margins below intended limits unless capacity is added in very small amounts and timed to come on line precisely when needed. It also makes capacity prices very volatile. In addition, its steepness creates incentives for larger generators to offer capacity at prices above the demand curve (albeit at Commission approved mitigated levels) and for buyers to induce excess new capacity via out-of-market purchases (without any mitigation or limit). Reducing the slope by moving the zero price point from 118 percent of minimum reliability requirements to somewhere in the range of 125-130 percent of minimum reliability requirements would improve market performance in all of these dimensions. This change would better enable the market to maintain revenue adequacy and reduce volatility in the face of lumpy additions of capacity such as have occurred recently in the New York City market.

Maintain the Concept of DGO Bid Caps

Bid Caps were an agreed-upon condition of the sale of the ConEd units. While the economic significance of the caps is eroding as their level sinks further and further below the cost of new entry due to inflation, they remain relevant under some market conditions. As a part of this package of reforms, and in conjunction with extending the length of the demand curve, KeySpan is willing to discuss an adjustment of the bid caps.

Retain Must Offer DGO Requirements

No change is proposed. DGO capacity must be offered to the market.

Impose a Floor on Bids for Certain Resources

As discussed previously in this paper, the effect of out-of-market purchases of excess capacity is to reduce capacity market prices to the point that the capacity mechanism cannot achieve its intended purpose. Only certain parties can benefit from exercising such monopsonistic behavior (though all buyers will pay lower prices if one or more firms do so). Such parties are either large market buyers with POLR responsibilities or state agencies, neither of which is subject to the shareholder profitability discipline on exercising monopsony power to the degree faced by other market participants. Simply lengthening the demand curve will not discipline such monopsonistic behavior.

KeySpan proposes that any new capacity built or acquired via out-of-market bilateral transactions by such parties should have a minimum bid equal to a percentage of the cost of new entry ("CONE"). This requirement would apply only to capacity acquired after the inception of the demand curve – *i.e.*, March, 2003. This requirement would not, in and of itself, impose a floor on the capacity price, but would substantially reduce the incentive to invest in significant excess capacity at above market prices in order to reduce prices in the NYISO auction markets. While KeySpan is not proposing a specific relationship between the CONE and the bid floor, it is important to note that the ability and incentive to exercise monopsony power is at least as great as the DGO's incentive and ability to increase prices that gave rise to existing price and bid caps.

Remove Other DGO Restrictions

In the presence of the demand curve, the proposed adjustment of the bid cap for DGO resources,[34] and the existing requirements to make all capacity available to the market, the DGO price cap serves no purpose other than to deny market prices to DGOs when capacity truly is scarce. There is no reason or logic behind retaining the cap, and it should be abolished.

[34] Recall that the existing DGO cap already is below the CONE.

The ban on bilateral sales of DGO capacity should also be eliminated. Contrary to what is sometimes alleged, this does not create an enforcement issue for third party transactions since the counter-party will be unwilling to pay more than the NYISO market price for bilateral capacity. It is acknowledged that there may be a valid concern about sham transactions that undermine the DGO bid cap. To moot such concerns, KeySpan proposes that the requirement to bid all divested generation into the capacity market at or below capped bids be applied to any party acquiring the right to bid such capacity via bilateral transactions. The proposed floor is related only to bids; the price paid to such capacity would be determined by the NYISO auctions and would not be discriminatory.

LONGER TERM REVISIONS TO NEW YORK CAPACITY MARKETS

The RTOs bordering New York are establishing forward markets for capacity. The reasons why this is beneficial are well known and relate generally to market competitiveness, reliability, revenue predictability and the ability to finance new merchant generation. New York needs to craft a forward capacity market. KeySpan is not at present making any particular proposal, save that such a market needs to be sufficiently forward to allow new entry of the types of resources needed for meeting reliability economically, and that the long term market be backed up by shorter term balancing markets, particularly in view of the existence of retail access and demand response in New York.

It should not take a great deal of time to formulate the provisions of a forward market concept that supplants the existing/proposed revised New York capacity market. New York can avail itself of the numerous proposals and studies conducted for the ISO-NE and PJM markets as well as its own experience with its capacity market. Using existing stakeholder processes, there is no reason why a concrete, fully articulated capacity market design could not be developed within 12 months and implemented within 18 months. This would allow the new design to be implemented in time to procure the new resources necessary to meet load reliably before existing capacity surpluses are exhausted.