STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY **d/b/a AmerenCIPS and** **UNION ELECTRIC COMPANY** **d/b/a AmerenUE** **Petition for approval of tariff sheets implementing revised Market Value Index methodology.**	)	**Docket No. 02-0656**
COMMONWEALTH EDISON COMPANY **Proposed revision of Rider PPO (Power Purchase Option – Market Index), Rate CTC (Customer Transition Charge) and Rider ISS (Interim Supply Service), and to establish Rider CTC-MY (Customer Transition Charge – Multi-Year Experimental)**	)	**Docket No. 02-0671**
ILLINOIS POWER COMPANY **Proposed establishment of Rider MVI II, Market Value Index II.**	)	**Docket No. 02-0672**

Initial Brief of The RES Coalition

AmerenEnergy Marketing
Blackhawk Energy Services, L.L.C.
Central Illinois Light Company
Constellation NewEnergy, Inc.
MidAmerican Energy Company
Nicor Energy L.L.C.
Peoples Energy Services Corporation

Christopher J. Townsend
David I. Fein
Piper Rudnick
203 N. LaSalle Street, Suite 1500
Chicago, Illinois 60601
312-368-4000

DATED: January 29, 2003

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY	)	
d/b/a AmerenCIPS and	)	
UNION ELECTRIC COMPANY	)	
d/b/a AmerenUE	)	
	)	**Docket No. 02-0656**
Petition for approval of tariff sheets implementing	)	
revised Market Value Index methodology.	)	
	)	
COMMONWEALTH EDISON COMPANY	)	
	)	
	)	**Docket No. 02-0671**
Proposed revision of Rider PPO (Power	)	
Purchase Option – Market Index), Rate	)	
CTC (Customer Transition Charge) and Rider	)	
ISS (Interim Supply Service), and to establish	)	
Rider CTC-MY (Customer Transition Charge –	)	
Multi-Year Experimental)	)	
	)	
ILLINOIS POWER COMPANY	)	
	)	**Docket No. 02-0672**
Proposed establishment of Rider MVI II,	)	
Market Value Index II.	)	

INITIAL BRIEF OF
THE RES COALITION

AmerenEnergy Marketing ("AmerenEnergy"), Blackhawk Energy Services, L.L.C. ("Blackhawk"), Constellation NewEnergy, Inc. ("NewEnergy"), Central Illinois Light Company ("CILCO"), MidAmerican Energy Company ("MidAm"), Nicor Energy L.L.C. ("Nicor Energy") and Peoples Energy Services Corporation ("PES") (collectively, the "RES Coalition"), by their attorneys, Piper Rudnick, pursuant to Section 10-101 of the Public Utilities Act (the "Act") and Section 200.800 of the Rules of Practice of the Illinois Commerce Commission ("Commission"), hereby submit their Initial Brief with regard to the market value index ("MVI") proposals of Commonwealth Edison Company ("Edison" or "ComEd"), Illinois Power Company ("Illinois Power "or "IP") and Central Illinois Public Service Company d/b/a AmerenCIPS and Union Electric Company d/b/a AmerenUE ("Ameren") (collectively, the "Utilities") in the instant proceeding.

EXECUTIVE SUMMARY:

THE COMMISSION SHOULD DIRECT THE UTILITIES TO MODIFY THEIR MVI MODELS TO MORE ACCURATELY REFLECT THE ILLINOIS RETAIL MARKET

The Commission must act quickly and decisively in order to avoid the impending crisis that faces the Illinois retail electric market. The Utilities' MVI formulas are undermining the transition to competition in the Illinois retail electric market and the Commission's past work in developing that market. Only by issuing an Order in the instant proceeding that provides fundamental revisions to the Utilities' MVI models can competition continue to survive, much less grow in Illinois.

The Commission has held that the MVI process should yield a market value that reflects the **cost of electric power and energy delivered at retail**. (*See Order on Reopening*, ICC Docket Nos. 00-0259/0395/0461 (Cons.) at 164.) (Emphasis added.) Unfortunately, the Utilities' MVI models have consistently and systematically yielded market values which are much lower than the retail cost of electric power and energy and the Utilities' filings in the instant proceeding would do nothing more than tweak the methodologies at the edges. In short, the Utilities' MVI models are broken at their core, and unless the Commission steps in immediately to fundamentally fix the process, competition in the Illinois retail electric market is virtually assured to fail.

The retail electric market in Illinois has no input that is more important than the annual determination of the "market values." For each participant in the retail electric market, the "market values" and their associated market value energy charges ("MVECs") are **critical**.

For **customers**, the market values directly impact the overall rates that they pay for electricity and the opportunities available in the competitive market. First, the market values are used to calculate the "customer transition charges" or "CTCs." The CTC is applied to all customers who enter the competitive market, whether the customer receives power and energy from a retail electric supplier ("RES")[1] or from the utility on an unbundled basis through its Power Purchase Option ("PPO").[2] Second, the market values are an independent component of the utilities' PPO tariffs and set the benchmark against which RESs must try to compete.

For **competitors**, the market values determine whether competition can even exist in the Illinois retail electric market. Indeed, Commission Staff witness Richard J. Zuraski suggested that it would be appropriate for the Commission to adopt revisions to the MVI process to intentionally overestimate the market value, in order to promote competition. (*See* Tr. at 468-69.) Although RESs compete against each other's prices, if the market values are set too low, no competitor will be able to provide a product at a price lower than the utility's PPO.

---

[1] Third-party entities that are eligible to market power at retail in Illinois have come to be known collectively as "retail electric suppliers" ("RESs"). This term includes Alternative Retail Electric Suppliers ("ARES") as that term is defined in the Act, as well as utilities that are providing competitive services. (*See* Staff witness Zuraski, Staff Ex. 1.0 at 3.)

[2] As Staff witness Zuraski explained, "The PPO is, in essence, a bundled service that a utility is required by the Act to offer to non-residential customers if the utility chooses to impose a CTC. However, while the utility, under the PPO, continues to provide the entire panoply of traditional utility services as a single bundled package, the utility's PPO charges are unbundled into (a) a PPO administrative fee component, (b) a delivery services component, (c) a CTC component, and (d) a power and energy component. The Act requires the charge(s) for the power and energy component to be based on the same market values used in the computation of the CTC." (Staff Ex. 1.0 at 3.)

(*See* Crumrine Tr. at 785-86; Zuraski Staff Ex. 1.0 at 7.) If the market value is set too low, virtually all retail customers would be served by the utility under bundled service or under the PPO. In short, competition would flounder and could cease to exist because alternative suppliers would be unable to compete against the incumbent utility's price for electric power and energy.[3]

The determination of market values is also important to **utilities** seeking to collect transition charges. In the calculation of annual transition charges, the lower the market value, the higher the transition charge.

Given this delicate balance among all market participants, it is critical that the market value reflect the full cost of serving retail customers in Illinois.

I.

INTRODUCTION

The setting of the "market value" has been a "make or break" decision for the Illinois competitive market. Since the opening of the Illinois retail market to competition in 1999, all participants collectively have held their breath while the market value was determined. Each year, the market has required an extraordinary event for competition to survive.

The expert testimony of customers and competitors is unambiguous, and the history lesson is clear: the MVI models are broken at their core and are in need of basic structural revisions. The Commission cannot afford to anticipate that the Utilities or their affiliates will

[3] As Staff witness Zuraski explained, "a sufficiently underestimated MV will prevent customers from switching to a RES. Thus, even though a RES may be able to supply electricity to a retail customer at a rate that is less than the true market value of power and energy and less than the utility's own embedded generation costs, an underestimated MV in the CTC can prevent a RES from showing a customer any savings relative to the bundled rate. Basically the same problem can prevent a RES from showing a customer any savings relative to the PPO, as well." (Staff Ex. 1.0 at 7.)

intervene to salvage the competitive market or that wholesale prices will drop dramatically once the market values have been determined. If the Utilities do not accept the necessary revisions to their MVI models, the Commission should direct an immediate return to the NFF process.

A. STATUTORY PROVISIONS

The Act provides two separate methods for determining the market values to be used in the calculation of transition charges. (*See* 220 ILCS 5/16-112.) Market values can be determined administratively through the NFF process, as was the case during 1999 and 2000, or the market values can be determined through a market index methodology proposed by a utility, as has been done since 2000.

Section 16-112(a) of the Act defines market value, under a market index methodology, as "a function of an exchange traded or other market traded index, options or futures contract or contracts applicable to the market in which the utility sells, and the customers in its service area buy, electric power and energy . . .." (220 ILCS 5/16-112(a).) The Commission should focus upon several aspects regarding the way in which Section 16-112(a) of the Act is to operate.

First, any market index methodology must relate to a definition of "market" that takes into account not merely the geographic dimension of a market definition but also, at a minimum, a product dimension of a market definition. Retail customers buy power and energy that varies in price and quantity by hour, not fixed standard wholesale bulk blocks. (*See* RES Coalition Ex. 1.0 at 15.) When retail customers no longer purchase power and energy from the utility, the utility has the ability to resell retail power and energy that varies by hour. The Act requires that retail characteristics must be properly reflected in any market index proposal. (*See* 220 ILCS 5/16-112(k).)

RES Coalition witnesses Brent Gale, Vice President of MidAm, and former Commission Chairman Dr. Philip R. O'Connor, who is a Vice President at NewEnergy, explained that without proper adjustments to any raw "market values" drawn from wholesale data sources, there will be an inherent underestimation of the market value of power and energy that can be sold by the utility and bought by retail customers. (*See* RES Coalition Ex. 1.0 at 16.)[4] Any market value model should be properly adjust for the differences between the market providing the data (wholesale) and the market to which the data will be applied (retail). In addition, any market value model must recognize other applicable rules or tariff requirements that apply when serving retail customers (*e.g.*, scheduling, reserve margins, etc.). In short, the Act requires that the market value model be reflective of the operational and economic costs of serving retail customers.

Second, the Act states that an alternative determination of market value shall be ". . . a function of [an index] . . .." (220 ILCS 5/16-112(a).) As explained by RES Coalition witnesses Mr. Gale and Dr. O'Connor, the word *function* is defined in the dictionary as something closely related to another thing and dependent on it for its existence, value, or significance. (*See* RES Coalition Ex. 1.0 at 16-17 *citing* The American Heritage College Dictionary.) The determination of market value can be closely related to, and dependent upon, an exchange or market traded index, yet also contain appropriate adjustments. (*See id.* at 17.) Significantly, the Act does not require that market value be an exchange or market traded index, only that market value will be a *function of* an exchange or market traded index.

Third, the Act states that an alternative determination of market value shall be applicable to the market ". . . in which the utility sells, and the customers in its service area buy

[4] All citations to RES Coalition Exhibits 1.0, 3.0 and 4.0 are to the revised versions that were admitted into the record and filed via e-Docket.

. . ..” (220 ILCS 5/16-112(a).) It is a simple fact that retail customers buy retail power and energy that varies by hour and in amounts that are not known in advance. (*See* RES Coalition Ex. 1.0 at 17.) Indeed, the PPO – which is a product that is designed to reflect the market in which the utilities sell and customers buy – allows customers to buy energy on an hourly basis without any usage restrictions. Consequently, the market value applicable to any utility must be reflective of the unique characteristics of the retail load in that utility's service area, including this unknown hourly fluctuation in load.

Moreover, this portion of the Act is clear that market value shall be determined based on the market in which the <u>utility sells</u> electric power and energy. The Act does not state that market value shall be determined based on the market in which the <u>utility buys</u> electric power and energy. The Utilities have attempted to gloss over this language.

ComEd, for example, has argued in this case, as well as others, that market value represents the value of "freed-up" electricity that ComEd can resell as retail customers choose alternative suppliers. (*See, e.g.*, ComEd Ex. 5.0 at 2.) This approach is improper because it does not coincide with the definition for the market value index in the Act, and previously has been rejected by the Commission. (*See* 220 ILCS 5/16-112(a). *See also* <u>Order on Reopening</u>, ICC Docket Nos. 00-0259/0395/0461 at 164.) Every transaction has a seller and a buyer; the Act has clearly defined each of those as the utility (seller) and the customers in its service area (buyer). This distinction is crucial to defining the applicable market.

Fourth, the Act states that an alternative determination of market value shall be reflective of ". . . . electric power and energy." (220 ILCS 5/16-112(a).) Each of the three market index proposals fail to adequately reflect the *power* portion of this requirement – or "generation capacity" – when establishing forward prices. (*See* RES Coalition Ex. 1.0 at 17-18; RES Coalition Ex. 3.0 at 7-9.)

Finally, the Utilities have been afforded the unusual opportunity under the Act to "take their ball and go home" if they so choose. (*See* RES Coalition Ex. 1.0 at 19.) If the Commission orders changes to the Utilities MVI models that are not acceptable to the utility, under the Act the utility may simply opt for the administratively determined NFF for establishing market value. (*See* 220 ILCS 5/16-112(m).) As discussed *infra* Section VI(F), the Commission should not be intimidated by threats that the Utilities may reject necessary changes; a return to the NFF process is more desirable than continuing with the Utilities' fundamentally flawed MVI models.

B. HISTORY OF THE MARKET VALUE PROCESS

The annual determination of the market value strikes at the core of the competitive retail electric market. Based upon the three years of experience with the Illinois retail electric market, two things are clear. **First**, when real world market prices for electric power and energy stayed roughly the same or increased after the MVI data was collected, competition did not progress. **Second**, only when market prices fell significantly from levels when the MVI data was collected did competition progress. The Commission should rely upon this historic evidence to understand the deficient nature of the current MVI models and the need for certain modifications and adjustments to those models.

When the Illinois retail electric marketplace opened in October 1999, RESs were able to compete with the PPO in the ComEd service territory for three reasons. (*See* RES Coalition Ex. 1.0 at 20-21.) First, the NFF based MVEC was rooted in a review of utility wholesale contracts entered into prior to the commencement of retail competition and thus, were out of synch with the actual markets that had developed. (*See id.* at 21.) This process yielded a situation in which the MVECs were somewhat over-priced for the initial non-summer period in contrast to significantly under-priced summer MVECs. Second, in the wake of an agreement between ComEd and certain market participants to establish an "experimental" MVI for the year starting in May and June of 2000 there was the first instance of *ad hoc* market intervention. (*See id.*) In order to move the experiment along, ComEd made available to RESs a Full Requirements Portfolio ("FRP") power product for the 2000 Summer period since there were no summer supplies available at prices reasonably corresponding to the MVECs. (*See id.*) Third, relying on the FRP for summer supplies and the market for non-summer supplies, RESs were able to provide retail supply contracts to customers that covered one summer period and two non-summer periods. (*See id.*) These "sandwich" contracts "beat the PPO." The sandwiching of one summer period between two non-summer periods coupled with the availability of FRP service in the summer months allowed customers to realize a savings advantage compared overall to the PPO. However, this combination of events was unique and cannot be repeated.

By December 2001 and January 2002, the number of customers served by "flowed power" for the first time exceeded the number served under the PPO. (*See id.* at 24-25.) This phenomenon was possible only because real market prices fell to a level commensurate with the levels simulated by the MVI's deficient formula. At that time, market prices had fallen by about 40% from their highs and by well over a third from the period in which the MVI data were collected. (*See id.* at 25.) During this period of time, and this one time only, intervention by ComEd was not necessary since market developments over-rode the artificiality of the MVI formula. This over one-third disparity is approximately a 15 mil/kWh (.8¢/kWh or $81/MWh) difference when all factors are considered. (*See id*. at 26.)

The competitive market was thrown into turmoil when the new MVECs were issued in April 2002. Competitive activity came to a grinding halt. (*See id.* at 26-27.) Once again, ComEd intervened in the market to prevent a massive shift of RCDS customers to its PPO. (*See id.*) Only then were RESs able either to maintain customers on direct service power or to commence service to new customers. In contrast, Ameren saw most of its customers on competitive supply return to its PPO product and did not seek to intervene in the market as ComEd did. (*See id* at 26.)

ComEd has treated portions of the terms of this intervention as confidential, but has admitted that it effectively resulted in a 5 mil adder to the market value established in May 2002. (*See* ComEd Ex. 6.0 at 20.) Without discussing the amount of the "intervention" or "subsidy," the RES Coalition panel of Mr. Gale and Dr. O'Connor explained that the intervention by ComEd fell well short of curing the full deficiency, but combined with the drop in wholesale prices at the time, "Suffice it to say that the details of the intervention would lend support to the contentions of the RES Coalition that the MVEC pricing produced by the current MVI formula is deficient by approximately one-third **or 8 mils beyond the technical and structural changes proposed by the RES Coalition.**" (*See* RES Coalition Ex. 1.0 at 27.) (Emphasis in original.)

However, after certain elements of the intervention terminated, competitive activity has slowed considerably and RESs find it difficult to compete with the PPO. (*See id. See also* Tr. at 765.) RESs have been unable to either maintain customers on direct service power or to commence service to new customers. The number of accounts on direct service has been falling and the number on the PPO rising. Mr. Gale and Dr. O'Connor concluded that even with the intervention in place: "Competitive activity has stagnated and is regressing." (RES Coalition Ex. 1.0 at 28.)

Comparing the 2001 and 2002 situations emphatically illustrates that the current MVI formulas have a systematic bias toward the under-pricing of energy in the MVECs and the shifting of costs into the CTCs for the Utilities. A comparison of these two scenarios indicates that the current MVI calculations only will support competitive progress if significant market price declines can be assured following the setting of the MVECs and CTCs. Since no such assurance is possible, and prices are currently quite low, the Commission needs to act to change the MVI calculation if it wishes to support the continuing development of the competitive market. (*See id.*) Of course, if prices rise subsequent to the setting of the MVECs and CTCs then the overall problem for competitive conditions is exacerbated. As discussed in the panel testimony of RES Coalition witnesses Bollinger, Goerss, and Spilky, this is one of the reasons that the RES Coalition recommends that MVECs be calculated on a quarterly basis. (*See* RES Coalition Ex. 4.0 at 54.)

These experiences in ComEd's service territory teach valuable lessons that should influence the way in which the Commission approaches not only ComEd's MVI model, but also those of Ameren and IP. (*See id.* at 22.) The lack of an FRP option and difficult transmission service rules historically have made competitive retail service too risky and costly in those service areas. (*See id.* at 21-22.) However, as RTOs develop and transmission service rules are more uniform and more compatible with competitive retail service, it will be extremely important that the MVI used in the downstate utilities be accurate and sufficiently robust. (*See id.*)

The Utilities' current MVI models have been no better than the NFF process in accurately *simulating* the value of energy in the real world market. (*See* RES Coalition Ex. 1.0 at 29.) Neither the original NFF nor the MVI, in any incarnation, has been able to produce a market value for energy that was anything other than well under the actual market value of energy to serve retail customers in any twelve month period to which the MVECs applied. The bottom line result has been that the market values flowed through the PPO are too low compared to the actual market and that the non-by-passable transition charges flowed through to *all* delivery services customers have been too high. Thus, without intervention or an unexpected market development, a RES would not have been able to compete against the PPO, which is the true price-to-beat as long as customers are charged transition charges. (*See id. See also* Staff Ex. 1.0 at 7.)

This historical evidence demonstrates that the Utilities' faulty MVI is a problem that could easily kill the competitive market and it does not appear that it will be fixed by purely voluntary action on the part of the Utilities. This is true even if the Utilities previously have been willing to periodically step in and intervene in the market. The need for periodic, *ad hoc* intervention in the market to set things right is a testament to inherent flaws and inadequacies of the current MVI Models.

C. SUMMARY OF POSITION AND RECOMMENDATIONS

In addition to highlighting the importance of the instant proceeding to the competitive market, RES Coalition witnesses Mr. Gale and Dr. O'Connor identified three extremely important facts that set the backdrop for the current proceeding.

First, the Commission was made aware in 2001 that the MVI process was likely to yield market values that were inappropriately low. (*See* RES Coalition Ex. 1.0 at 4.) The

Commission was alerted to the fundamental deficiencies in the Utilities' MVI formulas and the Commission acknowledged that the formulas were insufficient. (*See id. See also* Order on Reopening, ICC Docket Nos. 00-0259/0395/0461 at 165.) However, at that time the Commission did not have a specific proposed model or methodology to smooth out the deficiencies that were identified in intervenor testimony. Therefore, the Commission did not correct many significant problems in the calculation of the MVI, such as the value and cost associated with serving unexpected load. (*See id.* at 166-67, 171-72.) While the Commission did not order the Utilities to provide information at that time that would have allowed key problems identified to be cured, the Commission did set several conditions for approval, including a termination date for the MVI formula and a required re-visiting that is the basis for the instant proceeding. (*See id.* at 156.)

Second, **the MVI formula is a *model* rather than a direct reflection of market prices**. (*See* RES Coalition Ex. 1.0 at 5.) As with any model intended to *mimic* real conditions, imperfections are inevitable. For every model, there is a "*residual*," that reflects some portion of the modeled reality that remains unexplained. The unexplained residual related to any given model may be attributable to many factors, including inadequate, faulty or missing data. The residual can also result from incorrect elements of the model that fail to capture the actual interplay between variables under real conditions and the subsequent failure to identify and incorporate important features of the actual phenomena being simulated into the model.

Third, **a *substantial unexplained residual* exists that is related to the current MVI models**. (*See id.* at 6.) Competitors and customers alike testified that this substantial unexplained residual is attributable to a number of specific, identifiable deficiencies, only a few of which were addressed in the Utilities' proposed revisions. The RES Coalition, the Building Owners and Managers Association of Chicago ("BOMA"), the Illinois Energy Consortium ("IEC"), and Trizec ("Trizec") presented substantial evidence demonstrating that the current MVI models are significantly flawed.

The RES Coalition, through a multi-method approach, identified a residual value of approximately 15 mils (1.5¢/kWh or \$15/MWh) relative to the actual value of power and energy for retail electric service. (*See id.*) This is the extent to which the current MVI under-prices the MVEC in relation to the observed market value of energy in the ComEd retail electric market. The technical and structural modifications to the MVI models proposed by the RES Coalition would reduce the unexplained residual to roughly 8 mils per kWh (.8¢/kWh or \$8/MWh) or about one-third of the current MVECs. (*See id.*) This remaining unexplained residual can be accounted for by directing the Utilities to include an adder to the MVI calculation.

The RES Coalition multi-method approach relies upon (1) a historical review of competitive conditions and switching since October 1999; (2) an analytical approach that deconstructs the MVI formula to reveal the numerical deficiencies; and (3) an empirical comparison of the MVECs produced by the MVI with prices of energy supplies in the real world market place.

1. **Historical Evidence.** The Commission now has three full years of experience with the retail electric market in Illinois. In that time, the MVECs consistently have been undervalued, requiring repeated interventions by ComEd and Exelon and a quirk in the wholesale energy market to address the deficiencies in the MVEC. (*See* RES Coalition Ex. 1.0 at 20-31. *See also* Trizec Ex. 1.0 at 4-5.)

2. **Numerical Evidence**. The Commission can look at the components that comprise the retail cost of electric power and energy and the value of the freed up power and energy to determine whether those components are properly reflected in the MVECs. The numerical analyses presented by the RES Coalition, BOMA and IEC

demonstrate that the current MVI methodology yields market values that are substantially lower than the retail cost of electric power and energy. (*See generally* RES Coalition Exs. 3.0, 4.0; BOMA Ex. 1.0 at 14-18; IEC Ex. 1.01 at 7-8.)

3. **Empirical Evidence**. Real world experience confirms that the MVI models yield MVECs that consistently are too low. Specifically,

   a. RES Coalition witness Dr. Marc Ulrich performed an independent **"NFF-like" analysis** of the contracts of the members of the RES Coalition. His results suggest that the actual MVECs would have been set **43% to 87%** higher if they were calculated using the NFF methodology rather than ComEd's MVI methodology. (*See* RES Coalition Ex. 4.0 at 41.)

   b. RES Coalition witness Dr. Marc Ulrich also performed an independent **"RES-MVI" analysis**, analyzing the actual contracts of the members of the RES Coalition that were entered into at the same time that ComEd's MVI process collected its inputs. His results demonstrated that the actual retail market price at the time ComEd was collecting data was **25% to 77%** higher than the MVECs generated by ComEd's MVI methodology. (*See id.* at 40.)

   c. The number of customers who have started receiving **RES-flowed power** during ComEd's most recent Applicable Period B **has decreased**. Customers **describe** the current market as "out of market" and "less attractive to consumers and suppliers when compared to other regions." (*See* IEC Ex. 1.0 at 5; BOMA Ex. 1.0 at 6.)

   d. The **actual prices** of electric power and energy in the market reflected that there are costs that **are not included** in ComEd's MVI methodology. (*See* RES Coalition Ex. 2.0, Attachments D, E; RES Coalition Ex. 4.0 at 9, 14-15, 40-41.)

In summary, it cannot legitimately be disputed that the MVI process yields MVECs that are too low. The historical evidence demonstrates that the fundamental structure of the retail electric market is tenuous at best, since in order to function it has required repeated interventions and dramatic shifts in wholesale market prices. The numerical evidence demonstrates that the Utilities' proposed MVI models do not capture the actual costs necessary to serve retail customers. The empirical evidence shows that the MVI methodology does not reflect the actual markets relevant to providing electric power and energy to retail customers in Illinois.

The Commission should step in and request that the Utilities fix the MVI models. While the Commission cannot directly impose a revised MVI on the Utilities, the Commission can identify what needs to be done and take additional steps to promote the development of the Illinois retail electric market. (*See* RES Coalition Ex. 1.0 at 30. *See also* 220 ILCS 5/16-112(m).)

If ComEd does not revise its MVI model as the Commission deems appropriate, the Commission can and should recognize the refusal as being a basis upon which to immediately rescind the recent declaration in that service for some customers under ComEd's Rate 6L is competitive. (*See* RES Coalition Ex. 1.0 at 30. *See also* Interim Order, ICC Docket No. 02-0479.) The Commission should recognize that the current MVI model is stifling competition and it will take some time for the NFF process to establish and implement market values that will allow competition to progress. As a condition of approving Ameren's merger with CILCO, the Commission is requiring Ameren to suspend its collection of transition charges until at least June, 2005. (*See Central Illinois Light Co. and Ameren Corp., Application for Authority to Engage in a Reorganization and Enter into Various Agreements*; Order, Appendix at 5, ICC Docket No. 02-0428, Dec. 4, 2002.) Should the acquisition of CILCO not go forward despite the companies' intentions, the Commission should grant Ameren's petition to suspend the collection of CTCs as proposed in Docket 02-0657 and require Ameren to revise its tariffs as proposed by the RES Coalition for possible inclusion in MVI tariffs that might take effect after the two-year suspension. In a partial settlement of the issues in the instant proceeding, the RES Coalition, Illinois Power and IEC provided the Commission with a basis for helping bring IP into line with the goal of developing the competitive market in its service territory. The RES

Coalition recommends that the Commission adopt the MOU and approve the use of a floating adder for Illinois Power.

The RES Coalition recommends that the Commission enter a Final Order that directs the Utilities to make the following adjustments to their MVI models:

(1) Properly account for **energy imbalances** by valuing the difference between the customers' forecasted and actual usage and pricing that difference based upon ComEd's hourly energy imbalance charge (*see infra* Section II(A));

(2) **IP and Ameren** should be directed to modify their MVI formulas to more accurately reflect **generation capacity costs;** (*see infra* Section II(B));

(3) Include a "**placeholder"** which would require the Utilities to **file amendments to their MVI models once they join RTOs**, to account for the resulting market changes, such as capacity requirements that would increase the cost of providing electric power and energy at retail (*see infra* Section II(C));

(4) Properly reflect the costs necessary to acquire and piece together **"odd lots"** to serve retail customers by making an upward adjustment to the current MVECs by approximately $.55/MWh (*see infra* Section II(D));

(5) Recognize the costs associated with **customer churn** (*see infra* Section II(E));

(6) Include an adjustment to account for the **residual error** that obviously exists in the Utilities' MVI models (*see infra* Section II(F));

(7) Allocate **sales and marketing costs** evenly per kWh rather than by the number of customers in each RCDS class in order to comply with the likely intent of the Commission's previous Orders to put in place an adder into the MVI formula which accounted for the costs related to marketing to non-residential customers (*see infra* Section II(L));

(8) **Eliminate the use of zeros in the PJM hourly price data** and to replace the zero (and negative) values with the average of the positive values *surrounding* the zero (and negative) values during the applicable month (*see infra* Section II(M)(1));

(9) Reflect the relative illiquidity of the Illinois markets compared to the Into Cinergy market by including an adjustment to the **basis adjustment** in the MVI models to account for the **liquidity risk** that is present in each market (*see infra* Section II(N)(1));

(10) Properly **synchronize the price shape and the demand shape** by organizing the actual demand hours for each 1x16 period across each respective month with

the PJM West relative price such that the greatest usage is multiplied by the greatest price (*see infra* Section II(O));

(11) Accept the settlement between most members of the RES Coalition, IEC and IP to allow for a **floating adder adjustment** to the MVI which would be recalculated every time Illinois Power recalculates market values, to account for hard to quantify costs that should be reflected in the MVECs (*see infra* Section III);

(12) Require ComEd to offer **multi-year CTCs for the remainder of the mandatory transition period** (*see infra* Section IV);

(13) Require IP to include a **rate for customers taking service under a multi-year contract who lose service due to a supplier default** (*see infra* Section IV(F));

(14) Reject the Utilities' **multi-year price shaping** proposal to average and "normalize" data since 1999 and instead utilize the highest summer peak and non-summer peak data to better reflect the way in which the market operates (*see infra* Section VI(A));

(15) Include the following operational **revisions to their tariffs**:

   (a) Require ComEd to **recalculate the MVECs on a quarterly basis**, to better reflect the actual workings of the markets (*see infra* Section V(A));

   (b) Reject ComEd's proposal to move back the **snapshot period** from March to January since it forces customers to make decisions when prices do not reflect the actual market (*see infra* Section V(B));

   (c) Reject the **"blackout" period** for the Rider PPO **enrollment** window (*see infra* Section V(C));

   (d) Require ComEd to calculate **custom CTCs** for customers with demands levels as low as **400 kW** (*see infra* Section V(D));

   (e) Allow **customer aggregation** to allow customers to reach the threshold **for custom CTCs** (*see infra* Section V(E));

   (f) Require ComEd to allow **all custom CTCs** to be available on **PowerPath** (*see infra* Section V(F)(1)); and

   (g) Adopt ComEd's proposed method for **previewing the CTC calculation** as long as all custom CTCs are available on PowerPath (*see infra* Section V(F)(2)).

(16) Include a requirement that the Utilities **monitor and report the availability of forward price data (both on-peak and off-peak)**, and provide that if the

Commission determines that such data is insufficient, the Commission could require the Utilities to estimate these prices using a competitive auction of forward products (*see infra* Section VI(B)); and

(17) Permit Ameren to suspend collection of CTCs as requested in Docket 02-0657 for a period of two years, with the appropriate modifications outlined above in the event that CTCs are reinstated after the two year suspension.

Finally, the Commission should provide in its Order that if the proposed revisions are not accepted by the Utilities, the Commission will take immediate action to address the situation, including reinstituting the NFF in time for ComEd's Period B MVECs and issuing an Order finding that ComEd's Rate 6L is no longer competitive. (*See infra* Section VI(F).)

As is discussed in greater detail below, the RES Coalition respectfully requests that the Commission enter an Order in the instant proceeding that fundamentally revises the Utilities MVI models in a manner that will yield the necessary improvements in time for ComEd's 2003 Period A MVEC calculations.

D. OTHER

II.

PROPOSED ADJUSTMENTS OR REVISIONS TO UTILITIES PROPOSALS

The RES Coalition's expert witnesses, along with witnesses from a wide variety of customer groups, emphatically testified that the Utilities' proposals are insufficient to rectify the problems inherent in the MVI methodology. The Utilities' proposed methodology fails to adequately capture the actual price at which customers in Illinois are served at the retail level. As a result, a number of additional adjustments are necessary.

The RES Coalition respectfully requests that the Commission enter an Order directing the Utilities to revise their MVI models to more accurately reflect the Illinois retail electric market.

A. <u>ENERGY IMBALANCES ADJUSTMENT</u>

When supplying its customers with electric power and energy, a cost associated with managing the risk that the RES will incur energy imbalance charges. ComEd witness William P. McNeil agreed that this is a risk that suppliers must bare each and every month. (*See* Tr. at 541.) Utilities impose energy imbalance charges when the "load" (or amount of energy) that a RES delivers to the utility does not equal the load that the RES's customers use for a given hour. As a result, the cost exposure to the energy imbalance charge is dependent upon how accurately customers' load can be predicted and upon how conditions have changed from the time when the load was purchased. (*See* RES Coalition Ex. 4.0 at 9.)

As explained by the RES Coalition panel testimony of Bollinger, Goerss, and Spilky, as a prudent business practice, suppliers, including the utilities, manage against the risk of incurring energy imbalance charges by purchasing products, so that the forecast can be followed with supply that has an energy supply tolerance. (*See id.* at 9.) When customers leave the utility's system and are served by a RES, the utility is relieved of the cost of managing the customers' unpredictable load and that cost is borne by the RES. However, the Utilities' MVI models do not reflect the costs that are incurred as a result of managing energy supply to meet customers' inherently unpredictable energy requirements.

1. An Adjustment To Reflect The Costs Associated <u>With Managing Energy Imbalance Risk Is Necessary And Appropriate</u>

An adjustment to the MVI methodology is necessary to reflect the costs associated with managing energy imbalance risk. These costs are (1) incurred by ComEd unless the customer takes service from a RES; and (2) incurred by RESs to supply retail customers in ComEd's service territory. Indeed, under cross examination, the RES panel of Bollinger, Goerss, and Spilky explained that virtually all of their contracts placed that risk upon the RES. (*See* Tr. at

349-52, 366-67.) ComEd witness Paul R. Crumrine also admitted that as long as a group of customers are served by the utility, the utility must manage its supply so that those customers do not put the system in imbalance. (*See* Tr. at 758-60.) Likewise, ComEd witness Crumrine admitted that once the customer is supplied by a RES, the utility is relieved of that risk. (*See id.*) Failure to include these costs is one reason that the MVECs have consistently and systematically been undervalued.

To understand why there is a risk of incurring energy imbalance charges, it is necessary to appreciate the various steps that must occur in supplying a retail customer.

First, a customer's expected usage is projected out into the future. (*See id.* at 7.) Such projections are based on historical load information and then modeled, primarily using weather relationships and monthly consumption patterns. Each RES then makes hourly energy purchases to meet its customers' expected requirements. The hourly energy purchase may occur months before the customer actually uses the energy.

Energy is then delivered to ComEd by the hour and is measured by the hour. (*See id.* at 8.) When weather conditions change, most customers' usage patterns tend to go in the same direction, so there is a net directional change. (*See id.*) The actual energy usage by the customer is not known until ComEd reads the customer's meter; there typically are 30 days between meter reads. Shortly following the end of each calendar month, ComEd reviews the deliveries for each hour and determines whether there was an imbalance each hour.

Differences between energy usage and energy deliveries are done in the aggregate, such that for each RES all of the individual customers' energy usage is totaled together for each hour and compared to energy deliveries for each hour. (*See id.*) Hourly actual usage is trued-up against hourly actual deliveries, and if they do not match, ComEd imposes an energy imbalance charge based on its OATT. Excess energy delivered by the RES is credited by ComEd at this energy imbalance charge rate and incremental energy requirements are purchased by the RES from ComEd at this rate.

As RES Coalition witnesses Bollinger, Goerss, and Spilky recognized, an energy imbalance charge could conceivably yield a credit when a supplier delivers more energy during a given hour than is consumed by a customer. (*See id.* at 12.) During the hours in which an "over delivery" occurs, a supplier receives the energy imbalance charge as a credit for the quantity over delivered. However, RES Coalition witness Bollinger, Goerss, and Spilky went on to note that in most of these cases, a supplier's cost to deliver this power exceeds the credit received from the energy imbalance charge. (*See id.*) Likewise, the converse situation can also occur. When the customers of a supplier consume more than predicted in a given hour, the supplier must purchase the shortfall based on the energy imbalance charge. (*See id.*) In many cases, the cost to supply this unexpected consumption is higher than the cost that would have been experienced had the unexpected load shape been anticipated. Additionally, any adjustments that ComEd makes based upon actual historical data, by definition, would fail to capture the cost associated with the risk that future charges could be greater than those previously incurred.

Ignoring the way in which RESs must operate, ComEd witness Crumrine asserted that RESs should simply purchase the appropriate amount of energy at the same time that the MVECs are set. (*See* ComEd Ex. 6.0 at 41.) Of course, such an approach, though simple in theory, would be impossible in practice, since it would require the RES to know **exactly** how much energy its customers would require for **every hour** of the **entire year**. Indeed, Mr. Crumrine's asserted "solution" merely serves to highlight the risks – and higher costs – that

RESs face because they cannot purchase all of their energy at the time the MVECs are set. Mr. Crumrine had no answer as to how a RES could predict factors such as customer growth (or loss), economic conditions, charges in a customer's operations, basis differentials, transmission rules, and rates, much less weather conditions for each hour throughout the year. (*See* Tr. at 775-83.) Indeed, the MVI-Study performed by Dr. Ulrich demonstrated that even when RESs price their offers during the exact same time that data is collected for the Utilities' RESs still are unable to come anywhere near the Utilities' low market values. (*See* RES Coalition Ex. 2.0 at 4, Attachment D; RES Coalition Ex. 4.0 at 40.) This is further strong evidence that the Utilities' MVI models do not account for numerous costs.

In an apparent attempt to further confuse the issue, ComEd witness McNeil suggested that "energy imbalance charges" are "delivery services" charges, that should not be included in the MVI calculation. (*See* ComEd Ex. 4.0 at 10.) However, RES Coalition witnesses Bollinger, Goerss, and Spilky explained that while energy imbalance charges and credits are passed through via the utility's transmission charges, the cost of managing generation supply to avoid incurring energy imbalance charges is a supply cost that should be reflected in the MVI methodology: "ComEd's delivery services rates merely provide the mechanism for ComEd to recover imbalance charges from RESs. The use of those tariffs to collect imbalance charges does not lead to the conclusion that the costs incurred to manage imbalance risk should be excluded from the MVI methodology." (RES Coalition Ex. 4.0 at 12.) The adjustment to the MVI models that is necessary is not intended to reflect the actual imbalance charges themselves; rather, the adjustment is necessary to reflect the cost of managing the imbalance risk that is shifted from the utility to the RES when a customer is supplied by a RES. Thus, despite the fact that imbalance charges are a charge imposed by the transmission provider, the costs of managing supply to avoid imbalances nevertheless are generation costs which should be reflected in the MVI methodology.

ComEd's assertion that the imbalance might favor the supplier again ignores the reality of the market. (*Compare* ComEd Ex. 6.0 at 23-24 *with* RES Coalition Ex. 4.0 at 12.) Given the relationship between price and demand, and the relationship of weather and demand, it is most likely that a supplier will have "under-supplied" during hot hours, when the price of energy is high; likewise, a supplier is likely to have "over-supplied" during cool hours, when the prices are low. (*See* RES Coalition Ex. 4.0 at 8.) Moreover, the adjustment that is necessary relates to *managing the risk of incurring imbalance charges*; this is a cost that exists regardless of whether an adjustment on a particular day is a credit or a charge. Nowhere in ComEd's MVI methodology is there an adjustment to capture this cost.

2. The Commission Should Adopt The RES Coalition's Proposal To Modify The MVI Methodology To Reflect The Cost Associated With Managing Energy Imbalance Risk

The RES Coalition presented expert testimony detailing the way in which the MVI methodology should be modified to capture the cost associated with managing energy imbalance risk. (*See* RES Coalition Ex. 4.0 at 10-11.) Building off their analysis of the deficiency, RES Coalition witnesses Bollinger, Goerss, and Spilky explained that the cost of following a customer's load could be modeled quarterly by using a set methodology based upon ComEd's hourly energy imbalance charge, the forecast of a customer's usage and assuming that the cost of the RESs energy supply is equal to the PPO rate. (*See id.* at 9.)

The cost could be modeled either by using the 0-25 kW customer class as a proxy for all of the customer classes or by using ComEd's actual data for each individual class. (*See id.* at 10-11. *See also* Tr. at 380-81.) The RES Coalition's analysis used information provided by

ComEd for such customer class for the June, July, and August 2001 time period. (*See* Tr. at 380.) Because the customers in this class usually do not have hourly interval meters, the hourly energy imbalance for this customer class is determined by an algorithm furnished by ComEd. Using ComEd's algorithm to forecast usage for the customer class, adjusting the actual usage for weather, and applying the PPO rate as the cost of supply, the net cost of the energy imbalance charge was calculated to be $3.95/MWh.

Consistent with the RES Coalition's recommendation that ComEd's MVECs be reset quarterly, the magnitude of the resulting energy charge would be determined for each quarter of the year. Quarterly periods are appropriate because ComEd revises the algorithm weather parameters each quarter. The quarterly rates would be averaged to determine the adder to cover for the cost of managing energy imbalance risk.

This analysis seems generally to reflect the type of prices that are seen in the wholesale market for products that would provide a means to manage the risks of incurring energy imbalances. One of the members of the RES Coalition received a bid in December 2002 for a period of 12 months for a hourly-shaped load that charged a premium of $4.63/MWh for a 5% swing from the shaped load that was being supplied. This "empirical data check" adds further credibility to the analysis performed by the RES Coalition.

This methodology is appropriate, since if market prices do not change much from the price at which the MVECs are set, there should be a relatively small adjustment. However, if prices change dramatically, the risk of incurring significant imbalance charges are significantly increased, and the adjustment would be larger. Indeed, this is a conservative approach because the only variable in this algorithm is weather; other changes, such as changes in the customers' processes are not accounted for in the algorithm.

The RES Coalition respectfully requests that the Commission direct ComEd to adjust its MVI methodology to account for the costs associated with managing energy imbalance risks.

B. CAPACITY BACKED ADJUSTMENT

Another cost that RESs incur in supplying customers in the Ameren and Illinois Power service areas is associated with the requirement of those utilities that RESs procure "generation capacity," the megawatts of electric power which can be physically delivered by an electric generating unit or system of units. (*See* RES Coalition Ex. 3.0 at 7.) Ameren and Illinois Power each require generation capacity with planning reserves in order to reserve network transmission in its respective service territory. (*See id*.) RESs currently are not required to obtain generation capacity to serve retail customers in the ComEd service territory, but this will likely change once ComEd joins the PJM Regional Transmission Operator ("RTO"). Additionally, despite ComEd's current business practice, the cost of acquiring generation capacity is a generally recognized cost to serve retail load and is a cost the incumbent utility does not have when RESs serve customers. (*See id*.)

As explained by the RES Coalition panel testimony of Bohorquez, Boyle, and Leigh, it is necessary for IP and Ameren each to revise its MVI formula to more accurately reflect the market price for capacity in each respective service area. However, revisions to the Ameren MVI methodology might not be necessary at this time due to conditions imposed upon Ameren by the Commission in the Ameren – CILCO merger proceeding. (*See Central Illinois Light Co. and Ameren Corp., Application for Authority to Engage in a Reorganization and Enter into Various Agreements*; Order, ICC Docket No. 02-0428, Dec. 4, 2002.) In the Ameren – CILCO merger proceeding, Ameren is committed to suspension of the collection of CTCs through May, 2005. (*See* Order, ICC Docket No. 02-0428, Appendix at 5.) The RES Coalition anticipates that Ameren will not impose any transition charges going forward and, therefore, will not offer a PPO. In the event that Ameren elects to reinstate the collection of CTCs after May 2005, amendments now might better ensure the calculation of MVECs and TCs are more accurate.

1. Appropriate Value For Generation Capacity In Illinois Power's MVI Formula

The structure of Illinois Power's applicable Riders MVI, PPO and Rate CTC tariffs allow for a unique manner of addressing capacity and energy prices in its service territory. (*See* RES Coalition Ex. 3.0 at 11.) Since under Illinois Power's tariffs the MVI is calculated on a more frequent basis than other utilities, the RES Coalition proposed an approach specific to Illinois Power, where IP will have a fixed value of $18.00 per kW-year assigned to capacity costs and a specific method of weighting each month of the year. (*See id.*) As described in the panel testimony of RES Coalition witnesses Bollinger, Goerss, and Spilky, this recommendation does not stand alone, but rather is just one component of an entire "floating adder" approach to revising the MVI formula. (*See* RES Coalition Ex. 4.0 at 61-62.) Indeed, in agreeing to a settlement of many of the issues associated with Illinois Power's MVI model, it was agreed to set this charge to $12.00 per kW-Year. (*See generally* IP Ex. 1.9.)

However, if the Commission rejects the "floating adder" approach, then the Commission should direct Illinois Power to adopt a tariff-based methodology, similar to the method that has been proposed by Ameren as modified by the testimony of the RES Coalition.

2. Appropriate Value For Adjustments To The Ameren MVI Formula

In its direct testimony, the RES Coalition recommended that since Ameren is operating in Illinois as an integrated distribution company ("IDC") and cannot market capacity or energy, Ameren should act as an independent facilitator of capacity auctions for serving retail load in its service area prior to MISO's implementation. (*See* RES Coalition Ex. 3.0 at 12 -13.) Therefore, for each period that Ameren calculates the market value, the company should also be required to conduct a capacity auction in which prospective buyers/sellers submit bids or offers indicating the amounts (MW) and prices ($/MW) at which they are willing to transact for capacity to serve retail load in the Ameren service area. (*See id.* at 12-13.) Then, Ameren would post the results to allow buyers and sellers to complete bilateral agreements as appropriate. Ameren would use the bid/offer data to establish a generation capacity value that would be added to the MVECs for the applicable MVI period. However, as discussed above, if Ameren does offer a PPO, the RES Coalition recommends that the Commission adopt Ameren's tariff-based methodology for inclusion of the value of generation capacity in its MVI methodology. The RES Coalition supports the proposal of Ameren witness Mr. Keith Hock to establish the generation capacity value through a tariff-based methodology that will rely upon values contained in the OATT administered by the Midwest Independent System Operator ("MISO"). (*See* Ameren Ex. 3.0 at 3-5.) It is anticipated that MISO will establish capacity and energy markets for prospective buyers and sellers in the future, but an implementation date has not been confirmed. (*See* RES Coalition Ex. 4.0 at 12.) The RES Coalition recommends that prior to MISO's implementation, the alternate method proposed by Ameren witness Hock be utilized in any applicable MVI calculation. (*See* Ameren Ex. 3.0 at 3.)

The RES Coalition respectfully requests that the Commission direct Ameren and Illinois Power to revise their MVI formulas to include a capacity backed adjustment.

C. INCLUSION OF "PLACEHOLDER" FOR POTENTIAL RTO-IMPOSED COSTS OR MARKET CHANGES (E.G. CAPACITY ADJUSTMENT)

As discussed above, RESs currently are required to obtain generation capacity to serve retail customers in the Ameren and Illinois Power service territories but not in the ComEd service territory. ComEd's requirements likely will change when it joins the PJM RTO. ComEd anticipates that it will become part of PJM in February 2003 and that PJM will be operational by the beginning of 2004. (*See* Tr. at 555.) However, the proposed rules, features, and costs of the PJM market are not yet known and may differ from those currently in place in ComEd's service territory. (*See id.* at 555-56.)

Therefore, it will be necessary to recognize the cost of generation capacity in ComEd's MVI tariffs once ComEd becomes fully operational under the PJM RTO because these generation capacity costs will be included in the cost of supplying retail load. (*See* RES Coalition Ex. 3.0 at 8.) Once ComEd's membership in the PJM RTO commences, ComEd's current OATT policy will terminate and the PJM capacity requirements for all load-serving entities will take effect for RESs in the ComEd service territory. (*See id.*) ComEd witness McNeil agreed that to the extent such capacity costs are incurred, they should be reflected in the MVI. (*See* Tr. at 559.)

In the instant proceeding, the Utilities have not adequately addressed how future PJM/MISO capacity requirements will be incorporated into their MVI models as a result of transferring control of their transmission systems to either PJM or MISO. ComEd witness McNeil acknowledged the potential for such necessary changes. (*See* ComEd Ex. 4.0 at 12. *See also* Tr. at 554.) However, neither IP nor Ameren address the impact that joining an RTO will have on the calculation of the MVECs. (*See* RES Coalition Ex. 3.0 at 9.) PJM and MISO policies require load serving entities, both RES and utilities, to provide capacity. PJM capacity policies likely will be implemented during the middle of the first Period A MVI proposed in ComEd's current filing. (*See id.* at 9. *See also* Tr. McNeil at 557-58.) Similarly, it is likely that at some point during the transition period, IP and Ameren will join the MISO. Therefore, the appropriate step at this time is for the Commission to direct the Utilities to include a placeholder in their MVI tariffs for PJM/MISO changes that impact the capacity value in the Utilities' MVI filings. (*See* Tr. at 460.)

Additionally, the placeholder in the MVI tariffs should require the Utilities to make a filing with the ICC amending the appropriate MVI, CTC, and PPO tariffs to properly account for all market changes resulting from the imposition of PJM/MISO policies shortly after PJM or MISO finalizes its market rules and the Utilities are fully functioning in the RTO.

The RES Coalition has recommended this straightforward solution to this issue, recognizing it is difficult to fully assess the effect on each utility and the costs imposed when the Utilities join a fully operational RTO. However, the record indicates that there is the potential for the following market changes:

- Transmission rates may change;
- PJM may impose a capacity requirement on Load Serving Entities;
- Character of Firm Transmission Service would change within PJM and MISO;
- Potential transmission congestion charges may require new hedging strategies and products not currently in existence;
- Financial transmission rights may affect the ultimate cost of serving retail load;
- The ComEd Hub may cease to exist;
- MISO may impose different capacity requirements than Ameren and IP currently have;
- Firm Liquidated Damages ("LD") Seller's Choice contracts would no longer be useful to serve retail load if they no longer hedge delivery risk adequately;
- Forward price quotes based on Firm LD contracts delivered into the Cinergy service territory may not be adequate proxies for power prices delivered into the ComEd, IP, and Ameren service territories; and
- Imbalance settlements would most likely be changed.

(*See* RES Coalition Ex. 3.0 at 23.) Thus, it is a reasonable prediction that, among other things, full implementation of the PJM and MISO markets will cause incremental costs such as the cost of compliance with RTO capacity requirements, residual congestion costs associated with a deficient allocation of firm transmission rights, and the cost associated with altered flow patterns on the transmission grid. (*See id.* at 23-24.) Since incurring these potential costs would be necessary to serve retail load, they should be eventually included in the MVI calculation.

There are also some other potential costs, such as changes in transmission rates, that need to be incorporated into ComEd's Rider TS because Rider TS, along with the MVI, determines the value of each RCDS customer's CTC. ComEd witness McNeil agreed that as currently drafted, Rider TS does not adequately account for expected or unexpected market changes. (*See* Tr. at 559.) In fact, the language in Rider TS does not describe how ComEd will calculate and allocate PJM-related costs described above. Furthermore, Rider TS is silent about other potential costs such as the cost of PJM imposed capacity. As it presently exists, Rider TS may not be used as a vehicle to adequately capture all PJM-related costs. It is important to properly account for all costs associated with ComEd joining PJM because these costs have the potential to affect the value of CTCs imposed on RCDS customers.

ComEd witness McNeil testified that ComEd has agreed to make such a filing to revise its methodology and tariffs to incorporate such changes. (*See* Tr. at 556-57, 560.) Similar costs and potential changes in transmission rates likewise could have an impact upon customers of Ameren and IP. The existing Ameren and IP tariffs do not adequately address these potential changes associated with membership in an RTO.

The RES Coalition respectfully requests that the Commission require the Utilities to incorporate a "placeholder" into their MVI tariffs requiring the Utilities to make a filing with the Commission amending all of their tariffs, once RTO market rules are finalized to properly account for all market changes resulting from the RTO implementation.

D. ODD LOT ADJUSTMENT

The Utilities' MVI models fail to properly capture the fact that there is a difference in the shape of retail load versus a wholesale block shape. (*See* RES Coalition Ex. 4.0 at 13.) It is undisputed that RESs have to schedule based upon the anticipated load shape of their retail customers. Thus, when a RES subtracts off the wholesale block shapes from the retail load shape, the RES is left with trying to acquire what the RES Coalition has termed "odd lot" schedules. (*See id.* at 4.) In other words, the RES is left with residual supply requirements according to the retail customers' load shape, which varies by hour (and in some hours are 0).

There is a cost premium associated with acquiring these "odd lot" schedules that should be included in the MVI calculation. (*See id.* at 13-15.) Historically, a variable schedule for "odd lots" has an average premium above a block schedule of 20% for the on-peak period and 30% for the off-peak period (as defined by NERC). (*See id.* at 15.) The RES Coalition submitted evidence that approximately 5-10% of CILCO's load fell into the variable "odd lot" category. (*See id.*) As a result, an upward adjustment to the current MVECs by approximately $.55/MWH would be appropriate. (*See id.*)

The RES Coalition respectfully requests that the Commission direct the Utilities to make an upward adjustment to their MVI models to account for the costs of acquiring "odd lots."

E. <u>CUSTOMER CHURN ADJUSTMENT</u>

As discussed in greater detail below, the independent analysis performed by RES Coalition witness Dr. Marc L. Ulrich demonstrates that the ComEd MVI methodology is flawed and does not capture the true market value of supplying electric power and energy at the retail level. (*See* RES Coalition Ex. 4.0 at 40.) However, the RES Coalition presented additional evidence that there may be other factors embedded into retail contracts that may not have been reflected in Dr. Ulrich's analysis, including the risk associated with customers exiting their contracts early ("customer churn"). (*See id.* at 42.) Therefore, the RES Coalition panel testimony of witnesses Bollinger, Goerss, and Spilky surmised that the risk associated with customer churn is not reflected in the RES contract prices that were analyzed by Dr. Ulrich's study. (*See id. See also* Tr. at 375, 377.) ComEd does not face similar risks from customer churn since ComEd's tariff requires a customer to remain on PPO until the following May billing period. (*See* RES Coalition Ex. 4.0 at 42.)

Accordingly, the RES Coalition respectfully requests that the Commission recognize that customer churn costs are incurred in serving retail customers.

F. <u>RESIDUAL ERROR TERM ADJUSTMENT</u>

The RES Coalition presented a multi-method analytical approach that demonstrated it is necessary and appropriate for the Commission to find that the Utilities' MVI models are deficient in specific ways and that the error term resulting from those deficiencies is now discernible and quantifiable. (*See* RES Coalition Ex. 1.0 at 6, 33-34.) In addition to specific technical changes to the Utilities' models, the Commission should direct the Utilities to apply a specific adjustment to account for that residual error term.

There is an undeniably large error term or unexplained residual in the Utilities' MVI models. (*See* RES Coalition Ex. 1.0 at 6.) To minimize the risk of continuing to produce an incorrect result, the Commission should apply a fixed adjustment to revise the model. As RES Coalition witnesses Mr. Gale and Dr. O'Connor explained, making an adjustment for an error term is customary as a means of addressing the problem of unexplained residuals in simulation models. (*See id*. at 34.) "Applying a fixed adjustment to a model is appropriate to the extent that the model is not specified in a manner that permits all relevant features of the reality being simulated to be incorporated into the model, thus leaving an unexplained residual." (*Id.*)

In the last MVI proceeding, even though the intervenors demonstrated and the Commission believed that the model proposed by ComEd was deficient, the Commission did not believe that it had an adequate basis for making revisions to the model. (*See id.*) In the instant proceeding, since the error term has been quantified, there is no reason to allow a deficient MVI to stay in effect without an adequate adjustment.

The RES Coalition has quantified the error term, or unexplained residual in the MVI models, based on the multi-method approach of (1) historical review, (2) analytical "build-up" and (3) comparison with prices derived from a survey of the market. (*See* RES Coalition Ex. 1.0 at 6.) Based on the RES Coalition's quantification, witnesses Mr. Gale and Dr. O'Connor concluded that the MVI methodology should be revised structurally and the ComEd and Ameren calculations include an upward adjustment of approximately **8 mils** per kilowatt hour ($0.008/kWh or $8/MWh) or about one-third of current MVI value. (*See id.*)

Other intervenors, including the IEC and Trizec likewise supported an upward adjustment. (*See* IEC Ex. 1.0 at 10-11; Trizec Ex. 1.0 at 3-4, 7.) IEC witness Grace testified that the actual retail electric prices are approximately forty percent (40%) higher than the recent ComEd MVECs. (*See* IEC Ex. 1.0 at 12. *See also* Tr. at 125-26.)

The RES Coalition respectfully requests that the Commission direct the Utilities to modify their MVI models to include an upward adjustment of 8 mils per kWh ($0.008/kWh or $8/MWh) to reflect the residual error term in their models.

G. RETAIL MARGIN ADJUSTMENT

H. AVOIDED ADMINISTRATIVE (AND RELATED) COST ADJUSTMENT

I. RETAIL UPLIFT ADJUSTMENT

J. AVOIDED PPO COST ADJUSTMENT

K. LOAD FOLLOWING ADJUSTMENTS

L. PROPER METHOD FOR ALLOCATING SALES AND MARKETING EXPENSES

The RES Coalition submitted detailed unrebutted and evidence that the current method used in the allocation of ComEd's sales and marketing expenses avoids a meaningful, material inclusion of these expenses in its MVI model. (*See* RES Coalition Ex. 4.0 at 21-30.) Under ComEd's current MVI model, expenses which should be allocated to the non-residential classes are almost entirely misallocated to the residential classes. (*See id.* at 21.) As a result, for those RCDS customer classes where most of the sales and marketing efforts are expended by participants in the ComEd service territory, there is very little adjustment or no adjustment at all.

In ComEd's 1999 delivery services tariff ("DST") proceeding, it was ordered by the Commission that "sales and marketing expenses should be accounted for in the MVI calculation." (*See* Order, ICC Docket No. 99-0117 at 103-04.) RES Coalition witnesses Bollinger, Goerss, and Spilky established that the Commission's "mandate" should be applied in a balanced and fair way, reflecting the manner in which ComEd itself employs numerous individuals who serve non-residential customers in what may be interpreted as a "sales and marketing" role. (*See* RES Coalition Ex. 4.0 at 21.) The Commission further expanded upon its position in its Order on Rehearing issued March 9, 2000 in the same proceeding. In the Order on Rehearing, the Commission concluded that it is necessary to account for the money retail marketers spend in their efforts to recruit customers. In order to estimate these expenses, the Commission directed ComEd to use, "ComEd's retail marketing expenses as a **proxy** for the level of costs that will be incurred by competitors in the Company's [ComEd's] service territory." (Order on Rehearing at 16.) (Emphasis added.)

ComEd has allocated over 90% of their total sales and marketing expenses to the residential customer class in the MVI methodology. (*See id.* at 24.) The RES Coalition presented four independent and unrebutted reasons why this allocation method is inaccurate and deflects expenses inappropriately away from those non-residential customer classes currently targeted by RES and with whom ComEd employees themselves engage in a significant amount of sales and marketing activities. (*See id.*)

In order to more accurately reflect the way in which such costs are actually incurred, these costs should be allocated evenly per kWh rather than by the number of customers in each RCDS class. (*See id*. at 28.) Such an allocation method would produce a simple and more accurate 0.026¢/kWh allocation for all customer classes. This would properly take into account the following facts: (1) the average non-residential customer account uses more than the average residential customer account; (2) more of ComEd's own sales and marketing efforts go toward serving the larger non-residential classes than is currently being recognized; (3) that the likely intent of the Commission's Order was to put in place an adder into the MVI formula which accounted for the costs related to marketing to non-residential customers; and (4) the allocation between RCDS Classes is consistent with the requirements of Section 16-112(k) of the Act. (*See id.)*

Additionally, the "per kilowatt hour" cost allocation method would adjust for discrepancies in the current method and allow for a more accurate reflection of the actual sales and marketing cost distribution of ComEd's own sales and marketing efforts to the non-residential customer classes. At the same time, this cost allocation method will serve to represent those costs incurred by RESs actively pursuing the non-residential customer groups. (*See id.* at 29.) It is imperative that this situation be remedied by allocating these costs evenly across all customer classes. In this way, the inequities in the current sales and marketing cost allocation method will be corrected.

Accordingly, the RES Coalition recommends that its "per kilowatt hour" solution for the allocation of sales and marketing expenses should be adopted as a more accurate association of the sales and marketing costs incurred for serving the non-residential customer classes.

M. OFF-PEAK ISSUES

1. Adjustment of Zeros and Negative Values in the PJM Hourly Price Data

ComEd relies upon PJM price data for calculation of the off-peak market values. In relying upon PJM price data, ComEd has improperly included zero and negative values in the PJM price data that are used to calculate the price shape in the ComEd service territory.

In the PJM hourly market there occasionally appear prices of \$0/MWh or less. In fact, the year 2001 saw 61 hours in which the PJM hourly priced reached \$0/MWh or less. (*See* RES Coalition Ex. 4.0 at 30.) The RES Coalition identified two main reasons why this issue is a matter of concern. First, the ComEd market typically has not exhibited hourly pricing values of zero or below. (*See id*.) Therefore, when the PJM pricing data (including the zero and negative hourly values) is used to create the ComEd MVI, it can lead to inappropriate and unrealistic results. Second, the use of zero (and negative) values affects the monthly proportions ("scalars") in ComEd's MVI calculations. (*See id*. at 31.) The scalars are computed by taking the average of the PJM hourly data and comparing them to the corresponding market prices derived during the snapshot period. The proportions between these average values are used to adjust the PJM hourly data.

Under ComEd's current MVI methodology only the zero (and negative) values which occur during the 5x8 periods of the PJM data are used when calculating the averages of the off-peak PJM hourly data. (*See id*.) These averages are then adjusted by the historic off-peak market prices to produce the off-peak scalars. However, based upon an analysis of PJM price data, the RES Coalition submitted unrebutted evidence that there are additional zero (and negative) values which occur during other off-peak times other than the 5x8 periods, specifically, the weekend and holiday periods. (*See id*.) In the current MVI methodology the weekend and holiday zero (and negative) values are not taken into account when determining the off-peak averages that produce the off-peak scalars. However, the off-peak scalars are used to adjust *all* of the prices in the off-peak hours including the weekend and holiday periods. Consequently, in the current methodology, the zero (and negative) values which occur during the off-peak weekend and holiday periods are not included when the off-peak scalars are produced, and furthermore, remain largely unaffected when adjusted (multiplied) by the off-peak scalars. (*See id*. at 31-32.)

Originally, ComEd proposed to replace the zero (and negative) values in the PJM price data with the average of the positive off-peak values for hourly prices for the applicable month. ComEd's proposal significantly *overstates* the hourly prices during these hours. These overstatements will cause the off-peak scalars to be too low and, when coupled with the typically low hourly consumption profiles during these hours, will most often tend to produce a pronounced downward affect on the resultant MVI. (*See id*. at 33.)

As a result, the RES Coalition recommended that the Commission direct ComEd to replace the zero (and negative) values with the average of the positive values *surrounding* the zero (and negative) values rather than the average of *all* the positive off-peak values during the applicable month. (*See id*.) Staff witness Zuraski made a similar recommendation. (*See* Staff Ex. 1.0 at 26.) The record demonstrates that this method produces more accurate and reasonable results than hypothetically may have occurred during the formerly zero (or below) priced hours. (*See* RES Coalition Ex. 4.0 at 33.) In its rebuttal testimony, ComEd agreed to accept the RES Coalition's proposal. (*See* ComEd Ex. 6.0 at 38.)

Therefore, the RES Coalition respectfully requests that the Commission direct ComEd to adopt the RES Coalition's proposal to substitute more realistic positive hourly price values during periods of time in which prices are very low.

2. <u>Other</u>

N. <u>BASIS ADJUSTMENT</u>

Each Utility's current MVI model contains a "basis adjustment." The term "basis" refers to the geographic differences in prices of the same product from one location to another. (*See* RES Coalition Ex. 3.0 at 18.) Thus, a "basis adjustment" adjusts for price differences between different locations. The Utilities' basis adjustments are determined from transaction data, such as the average of the daily ratio of the Into Cinergy energy price to the Into ComEd energy price. (*See id.* at 18-19.)

However, the basis adjustment in each utility's MVI model considers only the price ratio of day-ahead products and **improperly assumes** buyers or sellers of forward products in each utility's territory pay the midpoint of the bid-ask quotes. As explained by the RES Coalition panel of Bohorquez, Boyle, and Leigh, because the Into ComEd market is less "liquid" than the Into Cinergy market, an additional "illiquidity adjustment" is necessary. (*See* RES Coalition Ex. 3.0 at 13-22.)

As discussed fully in the panel testimony of RES Coalition witnesses Bollinger, Goerss, and Spilky, these specific adjustments may not be necessary for Illinois Power, if the Commission adopts the proposed "floating adder" approach that has been agreed upon by Illinois Power, the RES Coalition and IEC. (*See* RES Coalition Ex. 4.0 at 63-67.) However, if the Commission fails to adopt a "floating adder" approach, these revisions should be applied to Illinois Power as well as ComEd and Ameren. (*See* RES Coalition Ex. 3.0 at 13.)

1. <u>Illiquidity Adjustment</u>

The basis adjustment in each utility's MVI methodology considers only the price ratio of day-ahead products and, in so doing, erroneously assumes the Utilities' forward markets are as liquid as the Cinergy markets. That is, the Utilities' basis adjustments improperly assume that buyers or sellers of forward products in each utility's service area would pay the midpoint of the bid-ask quotes. Although such an assumption would be appropriate for liquid markets such as Cinergy, it is not appropriate in illiquid market such as those in Illinois. (*See id*. at 19.) In short, the Utilities' basis adjustments systematically under-value the MVECs by failing to account for the lack of liquidity in the Illinois markets.

a. **An Adjustment To Reflect The Illiquidity Of <u>The Illinois Markets Is Necessary And Appropriate</u>**

Utilities and RESs that purchase electric power and energy to serve retail load in Illinois are exposed to risks that are inherent in illiquid markets. (*See id*. at 21.) Due to the illiquidity of the ComEd, Ameren and IP markets, suppliers purchasing forward products will most likely pay a price closer to the "ask quote" rather than the "midpoint of the bid and ask" that is assumed in the Utilities' current MVI models. (*See id.* at 19.) Since suppliers in Illinois often pay closer to the ask quote, the MVI systematically underestimates the price suppliers in Illinois are paying. The Commission should direct the Utilities to modify their MVI models to reflect the realities of the retail electric market in Illinois.

RES Coalition witnesses Bohorquez, Boyle, and Leigh explained that in illiquid markets, such as those in which the Utilities operate, the expected price for a forward product is more likely to settle close to the ask (higher) quote if a buyer initiates the transaction. (*See id*.) Conversely, if the seller initiates the transaction it is more likely that the transaction price will settle close to the bid (lower) quote. This uncertainty in the price of a product translates to "liquidity risk."

There cannot be any serious dispute that Cinergy is significantly more liquid than the Illinois markets for both peak and off-peak products. (*See id.* at 19-21.) If that were not the case, it would not be necessary to use Into Cinergy as a proxy in the MVI calculations; instead, the Utilities would just use trades within their own forward markets. The fact that a proxy is necessary makes an illiquidity adjustment to the basis differential between the Utilities and Cinergy appropriate.

RES Coalition expert witnesses Bohorquez, Boyle, and Leigh explained that the liquidity risk in a market can be quantified by calculating the numerical difference between the bid and ask quotes. (*See id.* at 20.) This measurement is called the "bid-ask spread." The bid-ask spread found in an illiquid market for a given product is much wider than the bid-ask spread found in a more liquid market for the same product. That is, a wider bid-ask spread indicates greater liquidity risk.

To further solidify the existence of the liquidity risk in Illinois, the RES Coalition presented substantial empirical data that demonstrated the "bid-ask spread" for the Cinergy market was substantially less than that for the same product, on the same day in the ComEd market. (*See id.* at 16-17, 20-21.)

b. The Commission Should Adopt The RES Coalition's Proposal To Modify The MVI Methodology To Include An Illiquidity Adjustment

The MVI methodology would be more accurate if the Utilities were required to include an adjustment to recognize the liquidity risk found in the forward markets of each utility. As RES Coalition witnesses Bohorquez, Boyle, and Leigh explained, ideally this adjustment could be done using the bid-ask information for the market of each of the Utilities, in which case one half of that bid-ask spread should be used. (*See id*. at 20, 22.) If, however, there is insufficient data from the Utilities' markets, the Commission could direct the Utilities to use the full bid-ask spread in the more liquid Cinergy forward market. (*See id*.) Since the Utilities have proposed using a basis adjustment for both peak and off-peak prices, the "illiquidity adjustment" likewise would be applied to both peak and off-peak prices.

The RES Coalition's experts presented two separate ways in which the Commission could estimate the size of the appropriate "illiquidity adjustment," both based upon the historical evidence of the bid-ask spreads for calendar year 2003. First, they explained that it would be appropriate to apply an adjustment of one-half of the bid-ask spread in the ComEd market. (*See id.* at 22.) As of late 2002, there was a bid-ask spread of $1.75, thus an adjustment of $0.88/MWh would have been an appropriate. (*See id.*) Second, the RES Coalition experts noted that given that ComEd, IP, and Ameren forward price data is scarce, the liquidity risk premium alternatively could be calculated using the **full** bid-ask spread found in the Cinergy market for forward products extending 12 months into the future. (*See id.*) As of late 2002, this alternative liquidity risk premium calculation also would have yielded $0.88/MWh. (*See id.*)

Under the RES Coalition's proposal, during each snapshot period, the Utilities would record the bid and ask quotes for a product extending 12 months into the future, and would calculate the bid-ask spread based upon the quotes that are recorded. At the conclusion of the snapshot period, the Utilities would calculate the average bid-ask spread. For example, for ComEd's Applicable Period A, in March 2003, ComEd would calculate the average bid-ask spread in Cinergy for a peak product and an off-peak product that extends from April 2003 through March 2004; the result of that calculation would be added to the Applicable Period A MVECs.

The RES Coalition respectfully requests that the Commission direct the Utilities to adjust their MVI models to reflect that the Illinois markets are less liquid than the Cinergy markets that are used as inputs to the MVI models.

2. Other

O. RES COALITION PROPOSAL TO SYNCHRONIZE PRICE SHAPE DATA FROM THE PJM MARKET WITH LOAD SHAPE DATA

Although the Utilities' MVI models do does include adjustments for both the shaping of customers' loads and retail prices, the RES Coalition presented unrebutted evidence that those two adjustments are not synchronized on an hourly or daily basis. ComEd's MVI methodology is flawed because it fails to properly match "price shape" data from the PJM market with "load shape" data from the ComEd market. In short, ComEd's methodology fails to adequately reflect the fact that the highest prices in ComEd's service area are likely to coincide with the highest demand in the ComEd service area. The RES Coalition proposed a straight-forward methodology to adjust the MVI model to account for this lack of synchronization.

1. An Adjustment To Synchronize The Price Shape Data From The PJM Market With The Load Shape Data From The ComEd Market Is Necessary And Appropriate

As RES Coalition witnesses Mr. Gale and Dr. O'Connor explained, the purpose of the MVI model is to try to simulate what a liquid retail market in each utilities' service territory would look like. (*See* RES Coalition Ex. 1.0 at 11.) If there were such a liquid market in the ComEd service area, all else being equal, an increase in demand, would result in an increase in price. Indeed, the Commission recognized the demand-price relationship in its Final Order in the last MVI proceeding, when it explained why hourly pricing was necessary: "Prices tend to be lower than average during shoulder on-peak hours and higher than average during the more peaked on-peak hours." (Order on Reopening, ICC Docket Nos. 00-0259/0395/0461 at 98.) Since high demand in a market is usually correlated with high cost in that market, the daily load shape and the price shape should be "in sync."

However, ComEd's MVI model does not necessarily yield such a result because the load shape data comes from the ComEd market and the price data comes from the PJM West market. (*See* RES Coalition Ex. 4.0 at 16.) Within any given day, these two markets are not "in sync." That is, an increase in *demand* in the ComEd service area, all else being equal, does not necessarily coincide with an increase in the PJM West *price*. Instead, PJM West pricing reflects a PJM load profile. This should not come as a surprise, since demand and price are driven to a great degree by weather. The weather in Northern Illinois oftentimes is quite different than the weather in Pennsylvania, Maryland, Ohio, Virginia and West Virginia (the states that are included in PJM West). ComEd's proposal relies upon PJM hourly pricing data that ComEd has failed to demonstrate is correlated to ComEd hourly load data.

The RES Coalition recognizes that this lack of synchronization "works both ways." (*See id.* at 17.) That is, there could be very low demand in the ComEd service area at the same time a heat wave hits Pennsylvania, resulting in a spike in PJM West price shape. However, as the panel of Bollinger, Goerss, and Spilky explained, the impact of this situation would not offset the underestimation because the change in the PJM West price shape would be multiplied by a low ComEd load to yield the adjustment. (*See id.*)

The lack of synchronization is different than the basis adjustment that is discussed *supra* in Section II(N). Those adjustments relate solely to trying to translate the "Into-Cinergy" trading hub values into prices for the ComEd service territory. In contrast, the lack of synchronization relates to the fact that the MVI methodology relies upon hourly price shapes obtained from the PJM West trading hub applied to hourly ComEd customer loads. (*See id.* at 18.) Although this is a different adjustment, the Commission should recognize that the same theory that justifies the "basis adjustment" likewise justifies synchronizing the price shape and load shape.

This issue deals with the cost of the shaped peak load. In addition, there still are other costs associated with imbalance risk management which deal with actual versus forecasted load, and odd lots which must be pieced together to serve a retail customer's load shape.

2. The Commission Should Adopt The RES Coalition's Proposal To Modify The MVI Methodology <u>To Synchronize The Price Shape Data With The Load Shape Data</u>

A review of load data for the ComEd rate classes shows that in general two thirds of the energy required for the shaped peak load requirements over base load requirements takes place in 8 out of the 16 hours. (*See id.* at 17.) If demand is not properly matched up with prices even slightly, there can be a significant impact upon the calculation. Thus, the lack of synchronization between the hourly price shape and the hourly load shape artificially deflates the MVECs significantly. (*See id.*)

The RES Coalition presented a straight-forward methodology to synchronize the PJM-West price shape with the ComEd load shape. (*See id.* at 19.) Essentially, the Commission should direct ComEd to "line up" the demand and the price within each day, so that the greatest usage is multiplied by the greatest price. (*See* Tr. at 332.) As the panel of Bollinger, Goerss, and Spilky explained, "The 1x16 hours of demand would be sorted fom smallest to greatest and the same sorting process would be done with the adjusted PJM West hourly costs." (RES Coalition Ex. 3.0 at 20.) Each hour of demand within the day then would be multiplied by the corresponding cost, so that low demand hours would then be multiplied by the low costs, and high demands would be multiplied by high costs. (*See* Tr. at 332-33.) A similar process can be conducted for each rate class. (*See id.* at 333.)

The process becomes slightly more complicated as a result of ComEd's proposal to incorporate all of the hourly price and load data since 1999 in calculating future MVECs. The RES Coalition supports ComEd's proposal to expand the inclusion of this additional data only if the Commission includes the RES Coalition's proposal to synchronize the markets. As RES Coalition witnesses Bollinger, Goerss, and Spilky explained, expanding the number of years worth of data and then averaging improperly would make the market appear less volatile than it actually is. (*See id*. at 19.)

To properly reflect the volatility for which RESs must plan, instead of averaging those years as proposed by ComEd, the greatest summer value and the greatest non-summer value out of those years would be used to calculate the MVECs. The RES Coalition evaluated the option of requesting that the Commission take the highest value for each month. However, taking the greatest summer period and the greatest non-summer period appeared to be an equitable compromise, taking into consideration: (1) the way in which planning takes place from both the supplier and seller perspectives; and (2) the fact that MVECs historically have had summer and non-summer components. (*See* RES Coalition Ex. 3.0 at 20.)

The RES Coalition respectfully requests that the Commission direct ComEd to implement the RES Coalition's proposal to synchronize price shape data from the PJM market with load shape data for each respective on-peak day.

P. <u>OTHER</u>

III.

<u>FLOATING MVI ADDER PROPOSAL</u>

The members of the RES Coalition, with the exception of Blackhawk (collectively, referred to as the "Supplier Coalition"), entered into a Memorandum of Understanding ("MOU") with IEC and Illinois Power, recommending that the Commission allow IP to adopt a "floating adder" approach. With this approach, there would be an adjustment to the MVECs which would "float" or be recalculated every time Illinois Power recalculates market values. Such an approach appropriately addresses the operational barriers that continue to frustrate competitive development and focuses upon the actual workings of the competitive market in

IP's service area. The Commission should allow Illinois Power to implement the "floating adder" approach, including the further revisions that IP recommended at the hearings. (*See* Tr. at 169-76, 329-331.)

The purpose of a floating adder to the MVI is to account for hard to quantify costs that should be reflected in the MVECs. Examples of these hard to quantify costs are: imbalance risk costs, odd lot costs, and basis/liquidity risk issues. (*See* RES Coalition Ex. 4.0 at 63.) The floating adder specifically would not be designed to take into account the cost of capacity and capacity reserves; instead, there would be a separate, fixed adjustment to address capacity. (*See id*. at 66.) The floating adder also would not be designed to take into account any increased costs associated with Illinois Power joining an RTO. (*See id*.) As discussed *supra* section II(C), Illinois Power should be required to make a filing with the Commission amending its tariffs to properly account for all market changes resulting from the implementation of an RTO.

The floating adder approach would substantially reduce the risk to the utility of the MVI model producing MVECs that are too high and would reduce the risk to customers and competitors that the MVECs would be set too low. (*See id*. at 63.) The Commission should allow Illinois Power to adopt the floating adder approach, consistent with the terms of the MOU, as modified by IP at the hearings.

A. TO WHICH UTILITIES, IF ANY, SHOULD A FLOATING MVI ADDER APPLY

The RES Coalition presented testimony regarding the way in which the "floating adder" approach would operate in the Illinois Power service area. (*See id*. at 64-66.) Illinois Power's witnesses also explained at length the way in which this approach could be implemented to promote the development of competition for its customers. (*See* Illinois Power Ex. 1.6 at 4-7;

Exs. 1.7, 1.8, 1.9; Ex. 2.1 at 4-14.) According to the switching reports given to the Commission, for the period October 1, 1999 to August 31, 2002 only 1.8% of the total number of customers eligible for delivery services in IP's service area had switched either to the PPO or to RES supply. (*See* RES Coalition Ex. 4.0 at 62.) Because there have not been any "interventions" by Illinois Power, marketing to customers in Illinois Power's service territory has been stymied by the fact that RESs could not offer a product at a price below the MVECs contained in IP's PPO. (*See id*. at 63.)

To the extent that the Commission finds that ComEd should revise its MVECs on a quarterly basis, it might be appropriate for the Commission to direct ComEd to adopt a similar approach. (*See* Tr. at 390.) However, if the Commission decides to direct ComEd to adopt the "floating adder" approach, the Commission should reopen the record in the instant proceeding for the sole purpose of taking evidence regarding the way in which such an approach could be fashioned to fit the circumstances present in the ComEd market. For example, the Commission should take additional evidence regarding what the appropriate frequency would be for ComEd to recalculate its MVECs.

If Ameren seeks to reinstitute its CTCs at some future date, the Commission should initiate a proceeding in which Ameren should be required to address whether it believes a "floating adder" approach would be appropriate. (*See id*. at 391.)

B. <u>BEGINNING VALUE</u>

As set forth in IP Exhibits 1.8 and 1.9, the Capacity Demand Credit should be set at $12 per kW-year. The floating adder should initially be set at 3.5 mils per kWh ($3.50/MWh).

C. INCREMENTAL CHANGES

As set forth in IP Exhibits 1.8 and 1.9, the Commission should direct that automatic adjustments occur in increments of $1/MWh, based upon the level of "switching activity."

As set forth in Section 3 of the MOU, the level of "switching activity" should be defined as: (1) the total annual MWh either switching to or staying on RES supply in the current period, as compared to (2) the total annual MWh either (a) switching to or staying on RES supply, (b) switching to or staying on PPO supply, or (c) switching to bundled utility supply. Thus, the automatic adjustment is based upon the percent of switching customers that are switching to or staying on RES supply. If, in a given period, less than 33% of the switching customers are switching to or staying on RES supply, then the MVECs would be adjusted upward by $1/MWh. However, if in a given period more than 66% of the switching customers are switching to or staying on RES supply, the MVECs would be adjusted downward by $1/MWh.

Under the terms of the MOU, the Commission Staff would be empowered in certain circumstances to suspend the automatic incremental upward movement of the floating adder. This provision was included to guard against non-compliance with the MOU by a member of the Supplier Coalition. Any suspension of the upward movement of the floating adder would occur only if Staff in its sole opinion determined that either RESs were not marketing in IP's service area or that it had insufficient information to determine the level of marketing activity.

Contrary to the suggestion of Staff witness Zuraski, Staff only could suspend the upward movement of the adder; under no circumstances would Staff be placed in a position where it could reduce the adder. Rather, the only way in which the floating adder would be reduced is if more than 66% of the switching customers were switching to, or staying on, RES supply; in which case the reduction would be automatic.

D. LIMITS ON FLOATING MVI ADDER

As set forth in IP Exhibits 1.8 and 1.9, the floating adder shall never be less than $0/MWh nor ever be greater than $10.00/MWh.

E. DETERMINING LEVEL OF MARKETING ACTIVITY

As set forth in IP Exhibits 1.8 and 1.9, under the terms of the MOU, the Staff could suspend the upward movement of the floating adder, if it determined that a sufficient marketing effort was not occurring. To assist in that determination, the members of the Supplier Coalition have agreed to provide Staff with a compliance filing of an affidavit specifying the marketing activity to IP customers.

Alternatively, if Staff is unwilling or unable to accept this role, Illinois Power witness Blackburn proposed at the hearings that the affidavit could be filed with Illinois Power, and the burden would be placed upon Illinois Power to come forward with a filing requesting that the Commission suspend the upward movement of the floating adder. (*See* Tr. at 201-02.) This alternative approach, while less desirable, would be acceptable to the RES Coalition. (*See* Tr. at 169-76, 329-31.)

F. OTHER

IV.

MULTI-YEAR OPTION ISSUES

The Utilities' proposals to allow for multi-year MVECs and CTCs clearly represent a step in the right direction. In a number of forums, including the instant proceeding, customers and RES have recommended that the Utilities provide a multi-year MVEC and CTC option.

(*See* RES Coalition Ex. 1.0 at 35; DOE Ex. 1.0 at 5; BOMA Ex. 1.0 at 27-28; IIEC Ex. 1.0 at 4; Staff Ex. 1.0 at 30; Trizec Ex. 1.0 at 9-10.) A properly designed multi-year MVEC/CTC or "lock-in" option will provide increased opportunities for customers to participate in the competitive market. (*See* RES Coalition Ex. 1.0 at 35.)

Customers desire to have price certainty of the CTC for periods greater than one year, including the option to lock-in CTCs through the remainder of the mandatory transition period. The RES Coalition estimates that roughly half of RES customers on direct supply could reasonably be expected to commit to contract terms through the transition period, if CTC and MVEC volatility was no longer a concern. (*See id.*) The RES Coalition also presented evidence that for planning purposes and POLR issues, the ability to have a multi-year MVEC/CTC through the remainder of transition period is of value to the Utilities. (*See id.*)

Furthermore, ComEd has failed to present any meaningful technical or operational constraints that should preclude ComEd from offering a multi-year CTC and a "multi-year CTC credit" for the remainder of the transition period.

A. AVAILABILITY OF MULTI-YEAR CONTRACTS

B. LENGTH OF MULTI-YEAR CONTRACTS

It is essential that customers be allowed to elect to lock-in their multi-year MVECs and CTCs through the end of the mandatory transition period, not just for a two (2) year period. (*See id.* at 35.) Notably, Illinois Power has proposed a lock-in option for customers through the remainder of the transition period. (*See id.*) In the event that Ameren seeks to reinstate the collection of CTCs, Ameren has agreed to offer a multi-year CTC through the end of the mandatory transition period. (*See* Ameren Ex. 4.0 at 4.) The Commission similarly should direct ComEd to offer customers the opportunity to lock-in their CTCs and MVECs through 2006.

C. Adjustments Of Multi-Year TC For Changes In Delivery Service Rates And Mitigation Factors

D. Market Value Adder Based On Length Of Contract

The RES Coalition recommends that the Commission direct the Utilities to provide a "multi-year CTC credit" to customers who commit to leaving the Utilities system for periods greater than one (1) year. The Utilities receive a tremendous amount of value when customers commit to leaving their system. For example, the Utilities

- avoid the cost of buying the generation output needed to serve the customer;
- are relieved of the obligation to serve these customers, which frees up multiple years of physically firm capacity and energy;
- are relieved of the costs and risks of possibly having to serve these customers under the terms of the PPO;
- are relieved of the obligation to provide these customers with regulated bundled service; and
- avoid the costs associated with reserving capacity for these customers.

(*See* RES Coalition Ex. 1.0 at 36.)

If the specific "floating adder" proposal for the Illinois Power service territory is adopted, no further credit or adjustment for a multi-year option would be necessary. (*See id.*) However, if the Commission does not approve the RES Coalition's "floating adder" settlement with IP, then the same multi-year credit discussed above should apply to IP to appropriately reflect the value that Illinois Power receives when a customer elects the multi-year CTC option. (*See id.*)

The RES Coalition has recommended that a 1.4 mil credit be provided for each year that the customer commits to forgo both the PPO and bundled service from the utility. (*See id*.) For example, if a customer elects a 2-year term under either the ComEd Rider CTC-MY or the IP Rider TC, the customer would receive a 2.8 mil credit to the CTC; a 3-year term would equal 4.2 mil credit and so forth. (*See id*. at 36-37.) This credit reflects some of the risk in the forward markets and works in a similar manner as the charge ComEd imposes on customers for the option to return to bundled Rate 6L. An additional benefit to the Utilities of this approach is that the multi-year credit would be fixed for each year of the multi-year contract between a customer and the utility thereby providing additional certainty to the Utilities.

The RES Coalition presented evidence that this adjustment represents an appropriate way of addressing the fact that there is value to the Utilities being able to dispense with the need to reserve capacity or to otherwise hedge for unexpected load that might return to the utility. (*See id*. at 37.)

The RES Coalition respectfully requests that the Commission direct the Utilities to provide customers with a 1.4 mil credit for each year that the customer commits to forgo both the PPO and bundled service from the utility.

E. LIMITATION ON LOAD ELIGIBLE FOR MULTI-YEAR TC CONTRACTS

Any limitation on the amount of load eligible for a multi-year transition charge must be specifically justified by ComEd. Based upon the record in the instant proceeding, ComEd has failed to do so. (*See* DOE Ex. 1.0 at 11; BOMA Ex. 1.0 at 28; Trizec Ex. 1.0 at 9.) Imposing a 500 MW limitation on the availability of a multi-year MVEC/CTC lock-in is inconsistent with ComEd's own position of wanting to have certainty and move customers off system supply and into the competitive market. (*See* ComEd Ex. 10.0 at 10. *See generally* ICC Docket No. 02-0479.)

Illinois Power has not proposed any limitations on the availability of its multi-year MVEC and CTC and has properly provided its customers with the opportunity to choose to enter into multi-year terms through the end of the mandatory transition period. (*See* RES Coalition Ex. 1.0 at 38.) In agreeing to suspend the collection of CTCs, Ameren also has in effect not limited the availability of a multi-year MVEC/CTC lock-in since all CTCs for each customer class will be eliminated. (*See id*.)

If the Commission concludes that ComEd needs some reasonable means to manage market growth and customers leaving their system, a customer-specific CTC may be a justifiable requirement for limiting the availability of the multi-year MVEC/CTC lock-in option with respect to certain customer groups. (*See id*.) However, under no circumstances should the Commission allow ComEd to prevent any customers for whom the provision of electric power and energy has been declared "competitive" from locking in its CTCs and MVECs for multiple years. It would be extremely unreasonable to prevent a customer from exercising a multi-year lock-in at the very same time that ComEd is scheduled to phase out its supply obligation to that customer and force such customers into the competitive marketplace. (*See id*. at 39.) ComEd has likewise failed to justify limiting the availability of a multi-year lock-in for those customers currently being directly served by RESs. ComEd has utterly failed to make a convincing showing of any significant burden.

In its rebuttal testimony, ComEd provides contradictory information regarding whether it is willing to remove the load restriction on the availability of Rider CTC-MY. In one instance, ComEd states that it is willing to "removing any limits on the total load allowed under the Rider [CTC-MY]." (ComEd Ex. 6.0 at 38.) Then, ComEd reverses itself and states that ComEd is "**not** willing to make Rider CTC-MY available for either an unlimited amount of total load or an unlimited amount of time." (ComEd Ex. 6.0 at 39.) (Emphasis added.) However, no further explanation or description of a reasonable load limitation is proposed, let alone discussed, by ComEd.

The RES Coalition respectfully requests that the Commission not allow ComEd to impose an arbitrary and unsupported 500 megawatt limit on the availability of the multi-year MVEC and CTC lock-in option under Rider CTC-MY.

F. IMPLICATIONS OF RES DEFAULT DURING MULTI-YEAR TC CONTRACT

The issue regarding the way in which supplier default should be handled was raised solely with regard to the operation of Illinois Power's multi-year CTC proposal in this proceeding. At the hearings, Illinois Power witness Brian Blackburn proposed a modification to its proposal to address the issue of a "provider of last resort" or "POLR" rate. (*See* Tr. at 197-99.) Under IP's original proposal, customers who took service under a multi-year CTC agreement would not have been entitled to return to be served by Illinois Power under any circumstances, even in the event of supplier default. At the hearing, IP witness Blackburn suggested that IP would be willing to offer a POLR rate to customers who are "dropped" by their RESs.

Under IP's proposal, the POLR rate would be based upon IP's current Rider ISS plus a 10% adder. At the conclusion of the normal Rider ISS term, if the customer failed to take service from a RES, IP would have discretion to either return the customer to bundled rates or keep the customer on Rider ISS, with the 10% adder. IP also would request that the customer provide some assurance that it had exhausted alternate supply possibilities. (*See* Tr. at 198-99.)

It would be appropriate for the Commission to direct Illinois Power to include a POLR rate in the event of supplier default.

G. OTHER

V.

TIME PERIOD AND TRANSITION CHARGE ADMINISTRATION ISSUES

A. FREQUENCY OF MV/TC CALCULATIONS (A. PERIODS A/B B. BI-MONTHLY C. QUARTERLY)

ComEd calculates its MVECs and CTCs under a Period A and Period B system twice a year. Illinois Power currently updates its MVEC calculations every two months or six (6) times per year. In order to be more reflective of the actual market in which the power is procured, the RES Coalition has recommended that ComEd's snapshots be taken on a more regular basis. As a compromise, the RES Coalition proposed that ComEd move to quarterly snapshots. (*See* RES Coalition Ex. 4.0 at 54. *See also* Tr. at 334-37.) Staff witness Zuraski agreed that from a customer perspective, the more often you calculate and update MVECs, the more likely you are to reflect current market conditions. (*See* Tr. at 491.)

The record supports a number of advantages and benefits of moving to quarterly snapshots. Specifically, quarterly snapshots would:

- allow the MVECs to more closely represent true market prices throughout the year;
- provide customers with the opportunity to evaluate the market throughout the year and decide when it is best for their business to take delivery services; and
- allow customers to choose when to lock-in MVECs and CTCs for a twelve-month period.

(*See* RES Coalition Ex. 4.0 at 54. *See also* Tr. at 336-37.)

Under ComEd's current structure, customers are forced to make a decision once a year within a very short time period after the MVECs are published. If they fail to decide at that point, many customers will be locked out of the PPO and potentially any type of delivery services for an entire year.

ComEd has failed to present any compelling technical, legal, or policy reasons for refusing to offer more frequent calculations of MVECs and CTCs. (*See* ComEd. Ex. 6.0 at 41-42.)

B. MOVING DATA COLLECTION PERIOD FOR APPLICABLE PERIOD A TO JANUARY

Under ComEd's current MVI tariffs, data for the Applicable Period A MVEC is in March for PPO prices beginning the following May. In the instant proceeding, ComEd has proposed to move the data collection period or "snapshot" of price information for Applicable Period A MVEC data from March to January. (*See* ComEd Ex. 5.0 at 13.) ComEd's proposal should be rejected as it would adversely impact the manner in which the MVECs are calculated.

The RES Coalition presented practical evidence that demonstrated that the closer the time period that the data is gathered to the actual delivery of the commodity, the better the prices will reflect the actual market. (*See* RES Coalition Ex. 4.0 at 46. *See also* Tr. at 491.) It stands to reason that when the MVEC data is collected, the data becomes "stale" and obsolete as soon as the collection period has passed and the data becomes less accurate the further the time period from the data collection period. (*See id*. at 46-47.) Therefore, if the Commission were to allow the Utilities to move the snapshot period from March to January, the data would be more stale at the time of the delivery of the power would be greater. The Commission should not allow the Utilities to exacerbate this problem.

Further, ComEd provided information and data in response to ICC Staff Data Request 1.01(d) that indicates that the trading volumes under ComEd's proposal are much thinner for the proposed January snapshot period than they are for the current snapshot period. Significantly, ComEd's response to Staff Data Request 1.01 shows the volumes traded during the January period are **only one-third** of what was traded during the current snapshot period for Applicable Period A. (*See* RES Coalition Ex. 4.0 at 47.) This will make the January data even less reflective of actual prices when the power actually begins to flow than the March data.

The RES Coalition identified the following additional practical implications which counsel against changing the snapshot period to January:

- First, when coupled with ComEd's proposed limitations on PPO enrollments, which are discussed in greater detail below, ComEd's proposal to move the snapshot would force customers to make decisions two (2) full months prior to actually receiving service.
- Second, ComEd's proposal would move the decision-making period further away from the summer peak period into the middle of winter, when customers are not as motivated to address their electricity supply options and costs.
- Third, these new requirements would add confusion for customers and burden customers and RESs with an unnecessary sense of urgency; customers may prefer a "wait and see" approach.

(*See* RES Coalition Ex. 4.0 at 47.)

Contrary to ComEd's assertions, RESs are unable to mitigate these deficiencies in the calculation of the MVEC merely by procuring power during the snapshot period. This practice would be highly speculative and generally does not make good business sense as it would expose RESs to even greater risk of having to buy or sell power in a market with ever-changing prices. (*See id*. at 48. *See also* discussion *supra* in Section II(A) regarding the resulting increased risk of incurring imbalance charges.) It would be quite risky for a marketer to lock-in prices that may or may not be lower than the MVECs particularly because at the time the MVECs are set, the number of customers and load a RES may serve during the corresponding period is unknown. (*See id*.) Even if the power was procured at prices lower than the MVECs, there is no guarantee in a competitive market that the marketer could sell that power in the load shapes and over the time period that it was purchased. (*See id*.). However, as illustrated by the RES MVI analysis presented by Dr. Ulrich, even if a RES were to attempt to procure supply at the same time that the MVECs are being set, the MVI methodology would produce a price significantly lower than the price that a RES could offer. (*See id*.) Prudent portfolio management will prevent a retail marketer from taking a long position during the snapshot period in anticipation of signing-up uncertain retail load in the future.

While ComEd's proposed data collection period and the resulting enrollment period would allow suppliers and customers additional time to evaluate their options, the resulting MVECs would become obsolete even sooner than under the current methodology. The record is clear that the true beneficiary of moving the snapshot period would be ComEd and its unregulated generation affiliate. (*See id*. at 49. *See also* Staff Ex. 2.0 at 5-6.) If the snapshot is moved to January, and ComEd's requirement for an enrollment "blackout" period is approved, ComEd will have additional certainty at an earlier date regarding their PPO load. (*See* RES Coalition Ex. 4.0 at 49.) This will inure to ComEd's benefit without providing any corresponding benefit to customers or competitors.

The RES Coalition respectfully requests that the Commission reject ComEd's proposal to move the snapshot period to January.

C. DECISION WINDOW FOR PPO CUSTOMERS

In the instant proceeding, ComEd has proposed to limit enrollment for PPO service under Applicable Period A to customers who sign up by March 31 and PPO service under Applicable Period B would be limited to customers moving from bundled rates. Since ComEd already has imposed multiple restrictions on the availability of the PPO and has not provided any plausible justification for these new limits, the RES Coalition recommends that the Commission reject ComEd's attempts to further frustrate customer choice and the development of the market.

The proposed enrollment window will not benefit customers. The restrictions as proposed will limit customers' available options after March 31 and may ultimately force many customers to choose the PPO for fear of losing the option all together. (*See* Tr. at 732-37.) While the proposed change in the publication date of the MVEC will allow customers additional time to evaluate their PPO option, customers currently choose the PPO throughout the year. ComEd has failed to provide any reason why allowing customers a longer decision window poses a problem.

ComEd has improperly asserted that customers and suppliers engage in "gaming" by moving on and off PPO service. However, ComEd witness McNeil admitted that his assertions regarding "gaming" merely reflected the exercising of rights of customers and suppliers under the Act and ComEd's tariffs, including the right of RESs to place customers on the PPO. (*See* Tr. at 539.) He also admitted that consistent with the Act and ComEd's tariffs, a customer exercising its option for service under the PPO "may sell or assign its interests in the electric power or energy that the customer has purchased." (*See* McNeil Tr. at 539. *See also* 220 ILCS 5/16-110(b).)

While customers can choose to go on and off PPO service, ComEd was forced to admit that this option is limited in three (3) ways. **First**, the customer must sign a PPO agreement with a term of up to a year. (*See* Tr. McNeil at 537-38. *See also* RES Coalition Ex. 4.0 at 52.) Customers cannot terminate this agreement except on 30 days written notice prior to the expiration date. (*See* Tr. McNeil at 538. *See also* RES Coalition Ex. 4.0 at 52.) **Second**, if a customer is already on delivery services, they cannot elect to go on PPO except once per year, after they have given 30 days notice. (*See* Tr. McNeil at 539. *See also* RES Coalition Ex. 4.0 at 52.) **Third**, if a customer leaves delivery services, they are not allowed back on delivery services or PPO for a period of at least 12 months due to the minimum stay requirements. (*See* RES Coalition Ex. 4.0 at 52. *See also* Tr. Crumrine at 753.) Such restrictions clearly limit any potential asserted "gaming" by customers or suppliers.

The RES Coalition respectfully requests that the Commission reject ComEd's proposed PPO enrollment window.

D. CUSTOMER ELIGIBILITY FOR INDIVIDUAL TC CALCULATION

ComEd has proposed to expand the availability of customer-specific CTCs to include customers with peak demands of one megawatt or more. ComEd approximates that an additional 1,400 customers will be able to receive individually determined CTCs. (*See* ComEd Ex. 5.0 at 15.) The RES Coalition supports ComEd's proposal for providing an additional benefit to the Illinois marketplace in that customers who receive a customer-specific CTC are assured to receive the statutory mitigation factor under the PPO and are also assured of greater savings opportunities under third-party RES supply.

However, the Commission should direct ComEd to lower the threshold to 400kW for customers to receive individually calculated CTCs. (*See* RES Coalition Ex. 4.0 at 56.) Unfortunately, ComEd witness Crumrine refused to indicate whether ComEd would accept such a revision. (*See* Tr. at 713-14.) Individually calculated CTCs are more accurate because the individual transition charge is directly related to the customer's actual load shape. (*See id*. at 56.) Therefore, the custom CTC more accurately reflects the customer's share of the transition charges than a class CTC. (*See id*.) Such a revision would add greater efficiencies to the restructured marketplace.

The threshold of 400 kW for individually calculated CTCs is the same threshold utilized by ComEd for requiring that customers install interval metering. Thus, in lowering the threshold, customer specific usage still would be utilized rather than basing the customer's CTC on a class profile. (*See id*.) Any costs to implement these changes, which benefit the entire ComEd market, should not be used as an excuse to limit choice for certain customers. (*See*, *e.g.*, Tr. at 709.) Any assertions regarding additional costs would be due to the increased volume of customers, not due to the creation of new systems or processes. The Commission should not endorse ComEd's upside-down theory that because an option is popular, access to the option should be limited.

The RES Coalition respectfully requests that the Commission direct ComEd to lower the threshold for individually calculated CTCs to 400 kW.

E. CUSTOMER AGGREGATION FOR INDIVIDUAL TC CALCULATION

The Commission should modify ComEd's tariffs to permit customers to aggregate load to attain the class size minimum required to obtain customer-specific CTCs. (*See* RES Coalition Ex. 4.0 at 58.) Under the RES Coalition's customer aggregation proposal, the actual calculation of the customer-specific CTC would operate as it would for the 400kW and greater customers. That is, each account under the aggregated load obtains a customer-specific CTC. (*See id.* at 58.) The opportunity to aggregate allows even more customers to realize the benefits of individually calculated CTCs as well as laying the foundation for greater utilization of aggregation type services by both RES and the Utilities.

To maintain an easily administered program, the RES Coalition proposes to limit the aggregation of load to entities sharing common ownership, much like ComEd's Rider CB. (*See id.*) Specifically, the RES Coalition proposes that only non-residential customers may aggregate for purposes of obtaining customer-specific CTCs and such customers must have at least five (5) customer premises. Each customers premise shall be owned or leased in its entirety by either the customer entity itself or by an entity such as a subsidiary, partnership, joint venture, limited liability company, or affiliate that the customer controls through ownership of more than 50% of the equity interest.

The RES Coalition respectfully requests that the Commission direct ComEd to modify its tariffs to permit customers to aggregate load to attain the class size minimum required to obtain customer-specific CTCs.

F. OTHER

1. The Commission Should Require ComEd To Make Individual CTCs Available On PowerPath

In addition to expanding the application of customer-specific CTCs, and to help the development of the competitive marketplace, the RES Coalition recommends that ComEd be required to make all custom CTCs available on PowerPath, along with an indicator that a customer does in fact have an individually calculated CTC. (*See* RES Coalition Ex. 4.0 at 59-60.) Currently, customers with individually calculated CTCs obtain that information directly from

ComEd via a letter. Unless a RES is a General Account Agent, ComEd will not provide that information to suppliers even with a customer's consent. Contrary to ComEd's assertions, access to information posted on the PowerPath website does require the consent of a customer. Additionally, only Class CTCs and usage information for customers are posted and available on the PowerPath website.

The posting of the customized CTCs would allow all customers equal access to the information that is required to make informed decisions regarding their competitive options for electric service. (*See id*. at 59.) With the limited time available for customers and RESs to evaluate their options, it is important that this information is available as quickly as possible. ComEd's current process is subject to other inefficiencies such as misplaced information or the information being sent to a different contact customer than the person evaluating competitive electricity options. (*See id.*) These inefficiencies cause time delays and customer confusion, which in turn result in missed "switch dates" due to ComEd's enrollment deadlines.

The RES Coalition respectfully requests that ComEd be required to make all custom CTCs available on PowerPath, along with an indicator that a customer does in fact have an individually calculated CTC.

2. <u>Release Of "Would-Be" MVECs</u>

ComEd has proposed to calculate and publish preliminary "would be" MVECs and CTCs by customer class during the snapshot periods. (*See* ComEd Ex. 5.0 at 15.) Unfortunately, after touting the benefits of providing more information to the market, ComEd stated that it is not planning to release the "would-be" MVECs on February 1, 2003. (*See* Tr. at 740-41.) The RES Coalition proposes that ComEd state in its tariff that ComEd will post such calculations on its PowerPath website, and that access will not be limited by password or other administratively burdensome criteria.

VI.

OTHER ISSUES

A. MULTI-YEAR PRICE SHAPING

One of the revisions proposed by the Utilities to their MVI models is to include data from additional years in calculating their price and load shapes. The current methodology uses the most recent year's worth of historical price and load data for shaping and weighting. Under the Utilities' proposals, they would use all of the available customer hourly load data and the PJM price data since 1999 in calculating future MVECs. (*See* ComEd Ex. 3.0 at 8.) The Utilities' proposals would calculate the price and load shapes for each year, calculate the resulting MVECs, and then average them. (*See id.*)

As the RES Coalition panel of Bollinger, Goerss, and Spilky explained, although the Utilities' proposal may sound appealing, if adopted, it would improperly distort the data, making the markets appear less volatile than they are in reality. (*See* RES Coalition Ex. 4.0 at 19.) "Using an average mathematically reduces the relative hour values, and it fails to adequately recognize the volatility in the market." (*See id.*) As ComEd witness McNeil admitted, Utilities and RESs must plan for normal conditions "with the appropriate reserve requirements." (Tr. at 545.) Thus, the Utilities' proposed that averaging the data would "normalize" the price and load shapes, even though Utilities and RESs cannot simply plan for "normal" conditions.

In order to better reflect the way in which the market operates, RES Coalition witnesses Bollinger, Goerss, and Spilky proposed that instead of averaging the historic data, the

Commission should direct the Utilities to use the greatest values from the summer and non-summer periods of prior years. (*See* RES Coalition Ex. 4.0 at 19-20.) Such an approach should be combined with the synchronization of the price and load shapes discussed in detail in Section II(O) of the instant brief. (*See id.*)

B. PRICE AND DATA AVAILABILITY -- MONITORING AND REPORTING REQUIREMENTS

The Illinois electricity market cannot yet be considered liquid and thus, the outcome of this proceeding cannot reasonably be the final step in creating true competition. Constant and ongoing review of the evolving competitive market and the Utilities' MVI tariffs is crucial if competition is to be fostered.

The Utilities' proposed methodologies for estimating forward wrap prices represent an improvement over the current methodology as the revised methodologies would yield prices that are a better representation of forward looking expectations for market prices. (*See* RES Coalition Ex. 3.0 at 15.) However, forward off-peak products are not traded as vigorously as peak products and the resulting limited availability of forward off-peak wrap prices makes an accurate estimation of these prices challenging. (*See id*. at 16.) This trading characteristic is equally true of the Utilities' markets as well as the PJM market which provides the source of estimated market prices in the MVI methodology. (*See id.*) This problem would be further exacerbated if the Commission were to accept the proposal of ComEd and Ameren to move the snapshot period to January, since even fewer market price data points exist for this time period.

As discussed above, evidence of the lack of forward off-peak wrap prices was presented by ComEd in response to ICC Staff Data Request 1.01, in attachment 1.01(d). Specifically, for the current snapshot period (data polled February 25, 2002 through March 22, 2002), ComEd reported only 15 observances of actual trades for a period extending forward more than 4.5 years (June 2002 through December 2006). (*See id.*) For the proposed snapshot period (data polled January 2, 2002 through January 29, 2002), ComEd reported no trade information for a period extending forward more than 4.5 years (June 2002 through December 2006). (*See id.*) This missing data undermines any assertion by the Utilities' that their proposals represent an accurate reflection of forward off-peak prices.

As a result, the RES Coalition recommends that the Commission require the Utilities to monitor and regularly report the availability of forward off-peak wrap price data. (*See id.* at 17.) The Utilities should be required to keep continuous valuations of off-peak wrap prices similar to the ones they keep for on-peak price data. (*See id.*) These prices should be updated during the Utilities' data collection periods. In the event that forward off-peak wrap price data is insufficient to adequately estimate forward prices, the Commission should then require the Utilities to implement an alternative methodology. (*See id.*) This alternative methodology could be based on prices resulting from a competitive auction of forward off-peak wrap products delivered in the Utilities' service territories. (*See id.*) The resulting prices would then be used to calculate forward prices.

The RES Coalition respectfully requests that the Commission direct the Utilities to monitor and regularly report the availability of forward off-peak wrap price data.

C. DR. ULRICH'S MVI-STUDY

The RES Coalition presented the independent expert testimony of Dr. Marc Ulrich, an economist and expert in risk management who has substantial experience with both the NFF and MVI processes in Illinois. (*See generally* RES Coalition Ex. 2.0.) Relying upon confidential and proprietary, verified contract information provided by the members of the RES Coalition, Dr. Ulrich presented the results of two empirical observations of what the MVECs would have been during ComEd's Applicable Period A, if the MVI methodology had relied upon actual data from the Illinois retail electric market.

The RES contracts that Dr. Ulrich analyzed did not include any PPO supply customers or customers on billing experiments; instead his studies focused solely upon "RES-flowed power." (*See id.* at 7.) Dr. Ulrich was given unfettered access to the contracts of the RES Coalition members in performing the audit that verified his results. (*See id.* at 3-4.) The results of Dr. Ulrich's studies convincingly supported the RES Coalition's position that ComEd's MVI methodology systematically and substantially underestimates the market values. (*See* RES Coalition Ex. 4.0 at 39-45. *See also* Tr. at 340.)

The first calculation that Dr. Ulrich presented was a Market Value Index study (the "MVI-Study") that correlated the contracts that RES Coalition members entered into at the same time that ComEd was collecting data for its the most recent Period A MVECs. (*See* RES Coalition Ex. 2.0 at 4.) As RES Coalition witnesses Bollinger, Goerss, and Spilky explained, since both the ComEd Period A MVECs and the RES contracts in the MVI-Study drew upon information from the same time period using similar forward market prices, if ComEd's MVI methodology were accurate, the prices should have been closely aligned. (*See* RES Coalition 4.0 at 40.) However, despite this commonality, the ComEd MVECs were significantly less than the prices contained in the RES contracts that were signed during this period. **The price differences between ComEd's MVECs and the RES contracts ranged from 25% to 77%**. (*See id.* at 40; RES Coalition Ex. 2.0, Attachment D.) This comparison demonstrates that the ComEd MVI methodology is flawed and does not reflect the actual market value of supplying electric power and energy at retail in Illinois.

RES Coalition witnesses Bollinger, Goerss, and Spilky explained that because the MVI-Study did not include adjustments for the terms and conditions of the RES contracts, the results of the MVI-Study are conservative. (*See* RES Coalition Ex. 4.0 at 42.) The terms and conditions of RES contracts typically contain restrictions that do not coincide with those found in the PPO. For example, unlike the PPO, many of the RES contracts have "pricing bands," which subject the customer to market based pricing for energy consumed outside the band. (*See id.* at 42.) Even with these additional terms, the RES contracts could not come close to matching the prices under ComEd's PPO.

ComEd presented the testimony of Ms. Cheryl Beach to rebut Dr. Ulrich's MVI testimony. However, ComEd witness Beach's assertions were demonstrably inaccurate and misleading; and the end result of her analysis reinforced Dr. Ulrich's conclusions. For example, Ms. Beach assailed Dr. Ulrich for allegedly including contracts that were outside the window used for the MVEC. (*See* ComEd Ex. 2.0 at 13.) However, upon cross-examination, she admitted that her data analysis methods were flawed, undermining her entire analysis. (*See* Tr. at 404-10.) Similarly, Ms. Beach erroneously asserted that Dr. Ulrich used contracts that did not coincide with the "prescribed contract start date" and the "prescribed contract end date." (*See* ComEd Ex. 2.0 at 13, 14.) Upon cross-examination, ComEd witness Beach admitted that Dr. Ulrich's studies did not require specific start and end dates, and that the contracts did run through the periods that Dr. Ulrich described. (*See* Tr. at 410-12.) Ms. Beach also criticized Dr. Ulrich's analysis because of the load factors that were reflected for several of the classes. (*See* ComEd Ex. 2.0 at 13-14.) However, upon cross-examination, she admitted that this data was not relevant to Dr. Ulrich's analysis. (*See* Tr. at 415-16.) In the end, ComEd witness Beach admitted that her analysis suggested that the load-weighted average market value for

RES contract prices were 62.8% higher than the MVECs; this amount confirms the range that was reported in Dr. Ulrich's study. (*See* Tr. at 418-19.) In short, ComEd's asserted criticisms of Dr. Ulrich's studies were baseless and misleading.

Dr. Ulrich's MVI-Study further supports the testimony of the RES Coalition, BOMA, IEC, and Trizec that the MVI methodology fails to capture many of the costs associated with serving retail electric customers in Illinois and, as a result, systematically undervalues the MVECs.

D. DR. ULRICH'S NFF-STUDY

In addition to the MVI-Study, Dr. Ulrich presented an NFF-Study, which also relied upon confidential and proprietary, verified and audited contract information provided by the members of the RES Coalition. Similar to his MVI-Study, the RES contracts that Dr. Ulrich analyzed for the NFF-Study did not include any PPO supply customers or customers on billing experiments. Instead his NFF-Study again focused solely upon "RES-flowed power." (*See* RES Coalition Ex. 2.0 at 4-7.) As explained by RES Coalition witnesses Bollinger, Goerss, and Spilky, wholesale contracts were not included because the purpose of the study was to create a retail price based on actual contracts and inclusion of such contracts would have been redundant. (*See* Tr. at 365, 386. *See also* RES Coalition Ex. 2.0 at 5-6.)

In the NFF-Study, Dr. Ulrich again tested the validity of ComEd's 2002 Applicable Period A MVECs, comparing those MVECs to MVECs that likely would have been produced by an NFF. He assumed that for a NFF to generate MVECs in time for the May 2002 billing cycle, the NFF would have needed to obtain the RES contracts by mid-September 2001. That is, if an NFF process had been in place in the third quarter of 2001, the same retail contracts analyzed by Dr. Ulrich would have been reviewed by the NFF and would have represented a large portion of the NFF contract population. (*See* RES Coalition Ex. 4.0 at 40. *See also* Tr. at 340.) Additionally, the RES Coalition testified that this time period was chosen because while the NFF in the past has employed calendar years, the RES Coalition wanted to present a comparison to ComEd's Applicable Period A. (*See* Tr. at 386.)

The price differences between the MVECs that were generated by ComEd's MVI methodology and the NFF-Study were significant, with the **NFF-Study MVECs ranging from 43% to 87% higher than ComEd's Period A MVECs**. (*See* RES Coalition Ex. 4.0 at 41. *See also* RES Coalition Ex. 2.0, Attachment E.) Thus, Dr. Ulrich's NFF-Study demonstrates that an NFF-based methodology would have produced significantly higher and more accurate MVECs than ComEd's existing MVI methodology.

Dr. Ulrich's NFF-Study provides further support for the position of the RES Coalition that the ComEd MVI methodology is fundamentally flawed and fails to accurately model the retail market for electric power and energy. Indeed, if the changes that have been recommended by the RES Coalition are not adopted by the Commission and accepted by the Utilities, it would be in the best interest of market development for the Commission to order a return to the NFF-based methodology, rather than rely upon ComEd's flawed MVI methodology. (*See* RES Coalition Ex. 4.0 at 41.) As RES Coalition witnesses Bollinger, Goerss, and Spilky noted, at least the NFF-methodology would be based on actual marketplace transactions rather than ComEd's mathematical construct, demonstrated to be flawed for several years. (*See id*.)

E. Mr. Sharfman's RPI Index

F. Reinstitution Of The NFF Process

The RES Coalition supports the Utilities continuing to utilize market index models if and only if those models are designed properly and operate as a faithful representation of the Illinois retail electric market. However, the Commission should not be afraid to resume the NFF process to calculate the MVECs. As discussed above, if the Utilities are unwilling to accept reasonable and appropriate modifications to the MVI formula now, the Commission immediately should resume the NFF process, in time to determine ComEd's 2003 "Period B" MVECs. The Commission should be confident that a reinstituted NFF process would be more beneficial than MVI models that repeatedly have been demonstrated to yield deficient MVECs.

While the NFF process used for the October 1999 opening of the retail electric market in Illinois produced MVECs and CTCs that were too low on a twelve-month-cycle basis, for at least five (5) reasons, a reinstitution of the NFF process in 2003 would be less likely to produce such a result. First, the competitive retail electric market is much more mature. The NFF now would have the benefit of relying primarily upon wholesale and retail contracts that were entered into in the context of a competitive wholesale environment with retail open access in some degree of operation. Second, customers are more familiar with their competitive options. As a result, there are likely many more contracts between customers and RESs that take into account the costs incurred to serve such customers. Third, the Commission, Staff and other interested parties have a better understanding of the costs associated with serving retail customers. This improved knowledge base will better inform the NFF. Fourth, most of the Utilities have become IDCs and have divested their generation assets. As a result, there are now contracts for the sale of power from those generating facilities, including contracts with the Utilities themselves, that would be included in the NFF data process. (*See* 220 ILCS 16-112(c), (k).) Finally, there are legitimate concerns about the potential for the manipulation of published power indices that are relied upon in the Utilities' MVI models. The contracts that would be evaluated in a new NFF process would not be subject to similar manipulation concerns.

A market index methodology that properly reflects the cost of serving retail customers, both operationally and economically, is more beneficial to the development of a competitive retail electric market than the administratively determined NFF. If properly designed, a MVI methodology should provide better price signals to the marketplace than the NFF. However, the MVI models used by the Utilities are fundamentally flawed, and unless they are significantly modified, the NFF might be a more desirable way to calculate market value. The results of the NFF-Study of Dr. Ulrich suggests that the NFF process would, to a large degree, capture all of the necessary adjustments to the MVI that the Utilities have declined to recognize.

G. OTHER

VII.

CONCLUSION

It is important for the Commission and all parties to acknowledge that no perfect market index methodology exists. The Illinois electricity market is simply not adequately liquid at this time. There are relatively few term transactions and there is no Illinois-specific hourly market upon which to build a market index. Moreover, there is still no active ISO or RTO in Illinois, and no actively traded futures or regulated forward market. Because there is no pure forward-looking transparent market in Illinois, the Utilities' MVI models have relied upon newly developing electronic exchanges, indices representing prices at geographic locations in other states for establishing on-peak forward prices, and historical spot prices to establish off-peak forward prices. In fact, the first two electronic exchanges that the Utilities relied upon – Altrade and Bloomberg – have ceased their operations. Nevertheless, certain facts and reasonable assumptions can be used to approximate the costs of serving retail customers. The RES Coalition has proposed detailed remedies that the Commission should direct the Utilities to adopt.

WHEREFORE, AmerenEnergy Marketing, Blackhawk Energy Services, L.L.C., Constellation NewEnergy, Inc., Central Illinois Light Company, MidAmerican Energy Company, Nicor Energy L.L.C. and Peoples Energy Services Corporation respectfully request that the Commission enter an Order in the instant proceeding that directs the Utilities to make the following adjustments to the MVI models:

(1) Properly account for **energy imbalances** by valuing the difference between the customers' forecasted and actual usage and pricing that difference based upon ComEd's hourly energy imbalance charge (*see supra* Section II(A));

(2) **IP and Ameren** should be directed to modify their MVI formulas to more accurately reflect **generation capacity costs;** (*see supra* Section II(B));

(3) Include a "**placeholder"** which would require the Utilities **file amendments to their MVI models once they join RTOs**, to account for the resulting market changes, such as capacity requirements that would increase the cost of providing electric power and energy at retail (*see supra* Section II(C));

(4) Properly reflect the costs necessary to acquire and piece together **"odd lots"** to serve retail customers by making an upward adjustment to the current MVECs by approximately $.55/MWh (*see supra* Section II(D));

(5) Recognize the costs associated with **customer churn** (*see supra* Section II(E));

(6) Include an adjustment to account for the **residual error** that obviously exists in the Utilities' MVI models (*see supra* Section II(F));

(7) Allocate **sales and marketing costs** evenly per kWh rather than by the number of customers in each RCDS class in order to comply with the likely intent of the Commission's previous Orders to put in place an adder into the MVI formula which accounted for the costs related to marketing to non-residential customers (*see supra* Section II(L));

(8) **Eliminate the use of zeros in the PJM hourly price data** and to replace the zero (and negative) values with the average of the positive values *surrounding* the zero (and negative) values during the applicable month (*see supra* Section II(M)(1));

(9) Reflect the relative illiquidity of the Illinois markets compared to the Into Cinergy market by including an adjustment to the **basis adjustment** in the MVI models to account for the **liquidity risk** that is present in each market (*see supra* Section II(N)(1));

(10) Properly **synchronize the price shape and the demand shape** by organizing the actual demand hours for each 1x16 period across each respective month with the PJM West relative price such that the greatest usage is multiplied by the greatest price (*see supra* Section II(O));

(11) Accept the settlement between most members of the RES Coalition, IEC and IP to allow for a **floating adder adjustment** to the MVI which would be recalculated every time Illinois Power recalculates market values, to account for hard to quantify costs that should be reflected in the MVECs (*see supra* Section III);

(12) Require ComEd to offer **multi-year CTCs for the remainder of the mandatory transition period** (*see supra* Section IV);

(13) Require IP to include a **rate for customers taking service under a multi-year contract who lose service due to a supplier default** (*see supra* Section IV(F));

(14) Reject the Utilities' **multi-year price shaping** proposal to average and "normalize" data since 1999 and instead utilize the highest summer peak and non-summer peak data to better reflect the way in which the market operates (*see supra* Section VI(A));

(15) Include the following operational **revisions to their tariffs**:

(a) Require ComEd to **recalculate the MVECs on a quarterly basis**, to better reflect the actual workings of the markets (*see supra* Section V(A));

(b) Reject ComEd's proposal to move back the **snapshot period** from March to January since it forces customers to make decisions when prices do not reflect the actual market (*see supra* Section V(B));

(c) Reject the **"blackout" period** for the Rider PPO **enrollment** window (*see supra* Section V(C));

(d) Require ComEd to calculate **custom CTCs** for customers with demands levels as low as **400 kW** (*see supra* Section V(D));

(e) Allow **customer aggregation** to allow customers to reach the threshold **for custom CTCs** (*see supra* Section V(E));

(f) Require ComEd to allow **all custom CTCs** to be available on **PowerPath** (*see supra* Section V(F)(1)); and

(g) Adopt ComEd's proposed method for **previewing the CTC calculation** as long as all custom CTCs are available on PowerPath (*see supra* Section V(F)(2)).

(16) Include a requirement that the Utilities **monitor and report the availability of forward price data (both on-peak and off-peak)**, and provide that if the Commission determines that such data is insufficient, the Commission could require the Utilities to estimate these prices using a competitive auction of forward products (*see supra* Section VI(B); and.

(17) Permit Ameren to suspend collection of CTCs as requested in Docket 02-0657 for a period of two years, with the appropriate modifications outlined above in the event that CTCs are reinstated after the two year suspension.

Finally, the RES Coalition respectfully requests that the Commission provide in its Order that if the proposed revisions are not accepted by the Utilities, the Commission will take immediate action to address the situation, including reinstituting the NFF in time for ComEd's Period B MVECs and issuing an Order finding that ComEd's Rate 6L is no longer competitive. (*See supra* Section VI(F).)

Respectfully submitted,

AMERENENERGY MARKETING
BLACKHAWK ENERGY SERVICES, L.L.C.
CENTRAL ILLINOIS LIGHT COMPANY
CONSTELLATION NEWENERGY, INC.
MIDAMERICAN ENERGY COMPANY
NICOR ENERGY L.L.C.
PEOPLES ENERGY SERVICES CORPORATION

By: ______________________________
One of Their Attorneys

Christopher J. Townsend
David I. Fein
Piper Rudnick
203 N. LaSalle Street, Suite 1500
Chicago, Illinois 60601
312-368-4000

DATED: January 29, 2003