THE JOINT COMMENTS

OF

THE CITIZENS UTILITIES BOARD,

THE CITY OF CHICAGO,

AND

THE COOK COUNTY STATE'S ATTORNEY

April 23, 2004

These comments are submitted on behalf of the Citizens Utility Board (CUB)[1] , the City of Chicago (the City) , and the Cook County State's Attorney (CCSAO) (collectively, CCC) to address questions raised by the Illinois Commerce Commission (ICC or the Commission) in its *Introduction to the Post 2006 Initiative* (Staff Whitepaper) and its *Illinois Commerce Commission Post 2006 Initiative Final List of Issues* (Final List). [2]

While we commend the Commission for including all the suggestions of parties for additional questions beyond those raised in Staff's Whitepaper, the expansion of the list from 27 to 93 items has resulted in significant redundancy and overlap. Thus, our comments will not address each and every question. These responses represent CCC's initial positions on these issues. CUB, the City and CCSAO hope to learn from the sharing of information and perspectives during this process and expressly reserve the right to refine or to modify their positions accordingly and to take positions on issues that we do not respond to as part of these comments.

1.1 Introduction

At the outset, we wish to emphasize a basic concern that should permeate the discussions in this process. The Commission and other stakeholders must recognize -- and prepare for -- the possibility that market developments will fail to achieve the optimistic expectations of advocates of greater reliance on competition in the Illinois electricity industry. In this context, one aspect of proposed market and regulatory mechanisms that should be examined closely in the workshops is the capability of any proposed regime to "fail softly" if the underlying projected market developments or other forecasts are wrong. With respect to electricity, which is essential to industry and commerce, as well as to every Illinois resident, we cannot afford expensive mistakes. The Commission must not prescribe policy based on faith in the invisible hand, without allowing for the possibility that it may be wielding an invisible stick.

Much has been made of the absence of retail competition for residential customers, despite the theoretically open market. CUB, the City and, CCSAO are all public advocates, yet we do not deem the lack of retail competition to date as evidence of the failure of restructuring, because the market and regulatory

1 These Joint Comments were prepared by CUB, the City, and CCSAO with the assistance of Synapse Energy Economics, Inc.

2 The City and CCSAO, along with the Illinois Attorney General's Office, are separately resubmitting an earlier filing by the City that proposes an alternative framework for examining the post-2006 issues identified in the Final List of Issue.

structures put in place during the transition period anticipated that price-constraining competition would not develop for residential customers.[3]

Will retail options for residential and small business consumers burst forth in Illinois with the end of transition charges and the unfreezing of utility rates? For several reasons discussed later in these comments, that is unlikely. However, the regulatory task at hand is not to predict the future, but to plan for the expected, while preparing for contingencies. It is not the job of state regulators to "promote" the appearance of retail marketers in Illinois through uneconomic incentives or unfair burden shifting. The objective should be pragmatic, not ideological: to determine the optimal combination of regulatory and market means to achieve the social goals that remain at the heart of the Public Utilities Act (PUA or the Act).

The range of options available to the Commission and Illinois stakeholders is not unbounded. Even as stakeholders and the Commission embark on a quest for innovative solutions to the unique problems of this transition, we must take account of the historical and current requirements of law and the expectations of stakeholders. Consensus on some key issues appears unlikely, given the differing interests of stakeholders. However, adoption of non-consensual policies that have the effect of reducing consumer protection or increasing the obligations and risks of service providers will be problematic, particularly if legislative changes are required. Therefore, this process should seek to identify our <u>real</u> options, given the legal, market, and political factors in place, and focus the workshop efforts accordingly. It will take leadership from the Commission to achieve such an outcome.

In defining realistic options, certain fundamental characteristics are requisites for public acceptance of any post-transition regime, particularly with regard to the procurement and pricing of regulated services provided to residential and small business customers. Any regulatory and/or market-based regime for provision of these bundled services must assure the adequate, efficient, safe, reliable, environmentally safe, and least-cost supply and delivery of electricity. (220 ILCS 5/9-102). The rates for consumers must be just and reasonable, whether the Commission relies on regulatory or market mechanisms -- or some combination thereof -- to achieve that result. (220 ILCS 5/9-101).

Rates for end-use consumers must also be affordable and reasonably stable. Because utilities no longer own most generation facilities, this will require that utilities prudently use the bulk supply and price hedging opportunities available for the large pooled demands their regulated service customer bases provide, so as to protect those customers against wholesale price risks that small-volume end-users individually cannot manage economically.

[3] We have yet to see evidence from anywhere in the country that price-constraining retail competition is viable for small-volume customers.

We hope that all stakeholders share our commitment to affordable rates and also to universal service, an unachieved goal that should not be abandoned in the post-transition era.

Regardless of the specific measures that are eventually adopted, the Commission must continue to follow all the public interest directives of the Act, adapting and interpreting them as appropriate to the changing circumstances in which they will be applied. The policies that are implemented will ultimately be judged by how well they achieve these enduring public goals.

1.2 Factual Background -- Status of Wholesale Markets in Illinois

The focus of this process is the provision of retail electric service to customers in Illinois in the post-transition period. Staff's Whitepaper correctly notes that the success or failure of retail competition after 2006 is largely contingent on the "development of a competitive wholesale market…." (Whitepaper at 3.) Indeed, if the wholesale market is insufficiently competitive or insufficiently regulated, then wholesale prices will most likely not be reasonable, and there is little or nothing that can be done in the design of retail service offerings that will "fix" that. Among the specific concerns are:

- highly concentrated generator ownership in most utility service areas;lack of incentives for diversified generation ownership;
- lack of incentives for independent generator entry;
- lack of incentives for adding transmission import capacity;,
- concerns about adequacy of the existing transmission system to support imports; and
- lack of transparency in the current wholesale market design.

Concerns about the wholesale electricity market are well founded. There have been bad experiences with deregulation, most notably the Western market crisis of 2000 and 2001. And in the current wholesale electricity markets there is much that is in flux. For Illinois utilities, there are issues concerning how the PJM and MISO regional Independent System Operators will develop and apply market power monitoring and mitigation measures to the markets that Illinois customers will depend upon for wholesale electricity.

ComEd, for example, will be a part of the PJM system, but it is not clear at this point in time what market mitigation rules and procedures will be in effect for the ComEd territory. The market rules in general, and the market power monitoring and mitigation procedures in particular, will be crucial to the issue of whether wholesale prices in the ComEd area will be reasonable.

A market power analysis done for ComEd by William H. Hieronymous, and filed with FERC in November 2003, applies FERC's Supply Margin Assessment (SMA) screen and found that ComEd control area would fail the screen. The analysis goes on the explain that this is "not surprising" because in a utility's "home control area" its customers are protected by requirements "to serve native load under cost-based regulation." The analysis goes on to apply a modified SMA screen in which load obligations are subtracted out of the analysis, and finds that on an "uncommitted capacity" basis that ComEd would pass the SMA screen. This "alternative" SMA test may be relevant to some question about market power, but it is certainly not relevant to questions about market power in the ComEd area post-2006, in which it is exactly these provisions about serving native load that are at issue. That is, a market power analysis that assumes that native loads are served at a cost-based or regulated price and concludes that there is not market power has answered a question that provides no comfort to anyone wondering whether a market based approach to pricing power to ComEd's customers post-2006 will work or not.

PJM filed comments proposing market mitigation measures for the Northern Illinois Control Area (NICA) to become effective when ComEd is integrated into the PJM markets. FERC's order approving ComEd's integration into PJM did not adopt the mitigation measures proposed by PJM, and the issue of what mitigation measures will be in place and whether they will be effective is far from resolved.

Recently, FERC issued an order in Docket Nos. ER96-2495-016 et al. that replaced the SMA test with two "indicative screens": (1) a pivotal supplier analysis that appears to be much like the SMA test; and (2) a wholesale market share analysis. The order explains that if an applicant fails either of the initial screens there it will have three choices. (FERC 2004b, p. 80.) First, it can file a "delivered price analysis" which could then lead to a FERC finding that the applicant does not have market power, or that the applicant does have market power and cost-based rates would be applied. Second, the applicantcan "file a mitigation proposal tailored to its particular circumstances that would eliminate the ability to exercise market power." Or third, the applicant can inform the FERC that will adopt cost-based rates.

It remains to be seen how these tests and options will apply to the Illinois companies in their "transitional" situation. The ICC and others representing Illinois interests should be actively involved in the FERC proceedings to develop effective wholesale market power analysis, monitoring and mitigation measures. The ICC and others representing Illinois interests should also be actively involved in the PJM and MISO stakeholder processes to promote the application of effective wholesale market power analysis, monitoring, and mitigation measures. The development and application of effective wholesale market power analysis, monitoring and mitigation measures will be essential in ensuring that electricity prices paid by customers in Illinois are just and reasonable.

It will be important also to keep in mind that the techniques designed by FERC for analyzing market power in the wholesale markets may not be applicable to analyzing market power for purposes of the ICC's decisions about retail service. For example, -- similar to Mr. Hieronymus's modified SMA analysis discussed above -- the analysis at the wholesale level may ***assume*** continuing obligations to serve native load at regulated cost-based prices, which is exactly the ***question*** that is at issue in the ICC's deliberations.

1.3 Factual Background -- Progress in Retail Choice

The Commission has characterized growth of retail competition in Illinois, generally, as "lackluster" and attributed that situation to "the absence of a dependable and transparent regional wholesale power market." As of February 29, 2004, less than 5% of small commercial and industrial customers and no residential customers have switched to delivery services. See, Table 1. Clearly, the majority of consumers in Illinois will continue for the foreseeable future to buy their electricity as a bundled utility service from their default service provider. Thus, it is more important than ever for the Commission to strike the appropriate balance between reducing costs and risks, while guaranteeing customers reliable, efficient electric service.

Table 1: Supply Options Chosen by Illinois Customers as of February 29, 2004.

Percentage of customers receiving electric delivery services	Residential	Small C&I	Large C&I	Governmental	Other	Total
Ameren CIPS	0%	1.0%	29.1%			0.20%
Ameren UE	0%	0.00%	0.00%			0
Commonwealth Edison	0%	5.1%	72.0%		1.0%	0.50%
Illinois Power	0%	1.6%	15.8%	0.2%		0.20%
Interstate Power and Light	0%	0%	0%			0%
MidAmerican Energy Company	0%	0%	0%			0%
Mt. Carmel Public Utility Company	0%	0%	0%			0%
South Beloit Water, Gas and Electric Company	0%	0%	0%			0%

Source: Illinois Commerce Commission.

That is not to say that we believe that the lack of retail choice is necessarily an obstacle either (1) to bringing the benefits of competitive procurement to residential and small commercial customers or (2) to providing certain choices to consumers, both of which are tasks well-suited to the local utility. Although retail choice has been available in a number of states for several years, nowhere has it been demonstrated that retail competition by itself adds value for residential customers beyond that which can be obtained from a well–designed program of procurement from competitive wholesale competitive markets. While there are many reasons for this, chief among them is the fact that the margins from retail sales at the relatively small volumes of individual residential and small business customers are far outweighed by the marketing and transaction costs of acquiring and serving them. It is axiomatic that it is less expensive to serve a combination of any two loads together than the sum of serving them separately. Thus, the idea of aggregation as the path to efficient procurement will tend to make utilities, which start with an aggregation consisting of 100% of the small customers' load, the dominant and perhaps only providers until such time as value is added to the commodity of electricity by retail marketers. We cannot predict when or how that will begin to occur, and will likely require innovation in technologies, bundling, and marketing. In the mean time it is imperative that the wholesale market be invigorated and that regulatory mechanisms are developed to ensure that bundled service utility customers have access to competitively sourced electricity at just and reasonable rates.

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1.4 Summary of the CCC Position

The Commission has identified serious concerns that require study and action. We recommend that a formal investigation be opened on these matters as soon as possible. A formal investigation will allow for clarity about the positions and supporting evidence of the parties and permit the issues to be joined efficiently and in a timely manner.
Whether the Commission opens such an investigation or continues with the present Post-2006 Initiative, we recommend that the Commission concentrate first on threshold issues, including measuring and dealing with market power, controlling abuse of affiliate transactions, evaluating and addressing demand response, and supply needs and transmission constraints on an equitable basis.

We further recommend that the Commission promptly require or conduct an independent review of current and expected market power in the wholesale electricity markets in Illinois. That review should take into account, at a minimum, current market functioning, potential changes in RTO or ISO membership, MMU capacity and authority, potential new generation supply and its ownership, and ownership relationships of generation in NICA and surrounding regions including the existing PJM region.

In the remainder of this report, we provide answers or comments in response to selected questions from the Commission's Final List of Issues. These responses focus primarily on the threshold issues mentioned above, but where feasible deal with certain other questions. We also provide comments and recommendations regarding the procedural directions set out in the Commission's *Post 2006 Initiative Workshop Process- "Rules of the Road"* document (Process Paper).

2. Answers to Selected Commission Questions

2.1 Power Procurement Issues

1) What are the overarching goals of post-2006 energy acquisition: promoting efficient wholesale and retail competition, assuring reliable current supply, encouraging adequate development of future resources, achieving the lowest average rate, and/or preservation of stable rates?

While all of these are laudable goals, we recommend that the Commission focus first on adequacy and reliability of generation supply and on maintaining reasonable retail rates for bundled service customers, while attempting to bring the benefits of wholesale competition to bundled service customers. The comments above and our answers to selected questions from the Commission's Final Issues List concentrate on those issues.

2) What electricity procurement strategies best achieve Illinois' policy goals? Should one strategy be used, or may different answers be appropriate in different circumstances?

We believe Commission decisions about procurement strategy relate, primarily, to protection of bundled service customers. We recommend a managed and diversified portfolio strategy for that purpose. The specifics of portfolio management strategies would, naturally, vary with the circumstances, but Executive Summaries of two reports written by Synapse Energy Economics, Inc.[4] generally summarize our view of portfolio management for Bundled Utility Service (BUS) procurement.

To reduce market price volatility risks, environmental regulatory and fuel price risks, the Commission should seek diversity in BUS supply procurement and require sound portfolio management techniques. The Commission should require that part of BUS requirements be acquired using fixed price, forward contracts of varied durations over time using a laddering approach. The Commission should also favor energy efficiency, demand side management, and use of varied supply sources, including renewables, to serve BUS customers.

3) What electricity procurement rules can be established by the Commission? To what extent do these issues lie within the exclusive jurisdiction of the FERC and federal law?

While we have not performed a complete legal analysis of this question, our understanding is that, at a minimum, procurement for default service, including Illinois's BUS, is within the jurisdiction of the ICC and the General Assembly.

[4] The executive summaries for "Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electric Services to All Retail Customers" and "Strategies for procuring Residential and Small Commercial Standard Offer Supply in Maine are attached hereto as Appendix A and Appendix B, respectively.

Aspects of BUS that we believe to be state jurisdictional include at least the following: procurement policies; standards for rate recovery of costs; alternative supply policies; energy efficiency program policies; affiliate transaction rules and codes of conduct for retail providers (FERC establishes codes of conduct for wholesale generators and transmission companies); provision of BUS; and energy assistance. In particular, we believe that procurement of supply or alternatives to supply for BUS lie within state jurisdiction, including but not limited to policies regarding portfolio management.

4) To what extent should the Commission provide specific guidance or direction to utilities regarding how they should conduct their supply acquisition activities? What assurances will parties participating in a such process have that the result will not be subject to subsequent change or review?

In general, we believe that the Commission should establish broad policy expectations with regard to procurement practices and portfolio management, leaving responsibility for carrying out those policies to the utilities providing bundled service. We address this question in more detail below in response to questions about possible energy plan requirements and possible pre-approval of such plans. Except as discussed in those other answers, we believe that no specific assurances are needed or appropriate. Post-transition procurement provides no reason to abandon the legal and regulatory principles of the prudence standard and just and reasonable rates.

5) What are the pros and cons of obligating utilities that do not own significant production assets to be responsible for active supply portfolio management? What alternatives are there? How can the market be used instead?

In recent years, those states relying upon short-term wholesale market prices for default services (e.g., Massachusetts, New York, Texas) have experienced higher costs and greater price volatility than other states with default services. Portfolio management offers a way to mitigate against higher costs and price volatility.
In all states, restructured or not, portfolio management is a way to deal with the evolving developments, uncertainties, and volatilities in the electricity industry. Bundled Utility Service customers of utilities that have divested themselves of generation can still benefit from a managed BUS supply portfolio, and we see nothing preventing such utilities from delivering those benefits to their customers. Former vertically integrated utilities have extensive experience with supply acquisition. If a utility, for some reason, has eliminated that competency from its skill set, energy portfolio management services are available from third parties.

As applied to the electricity industry, portfolio management rests on the simple notion that active participation in electricity markets and careful choices among a variety of electricity products and resources will provide more stable service to customers over both the short- and long-term future. The key benefits of portfolio management include:

- Portfolio management, if done well, will result in lower electricity costs, lower electricity bills, and more stable electricity prices, not only by purchasing more wisely for consumers' needs, but by injecting valuable discipline into wholesale markets.
- Portfolio management offers a way to shift the focus of electric utilities or default service providers from short-term, market-driven prices to long-term customer costs and customer bills. This shift allows regulators to maintain (or reintroduce) key public policy goals into the critical function of power procurement for the large majority of electricity customers.
- Portfolio management offers regulators a mechanism to promote energy efficiency, build markets for renewable generation, encourage fuel and technology diversity, and achieve environmental objectives.

In sum, portfolio management is not only consistent with competitive markets; it is, in fact, necessary to ensure that competitive wholesale markets are robust. These benefits can and should be delivered to bundled service customers, but are now being foregone in many jurisdictions, both restructured and traditional.

6) Is it appropriate for a distribution or “wires” utility to bear commodity risk, i.e., to have a retail rate structure and be subject to a procurement process that expose it to financial risk depending upon market behavior?

In a situation where a regulated utility is providing Bundled Utility Service, it is certainly appropriate to expect the utility to exercise prudent and economical management of the resources acquired to provide bundled service. Such management should include sound portfolio practices to control financial risk on behalf of bundled service customers. (Portfolio management practices designed solely to eliminate or minimize financial risk for the utility without regard to prudent and economical management on behalf of customers should not be considered appropriate.) With this background, the Commission may wish to consider appropriate ratemaking methods to balance the risks and rewards of the utility's enterprise, but should do so with the entire enterprise in mind, not just the commodity purchasing function for bundled service.

Moreover, it is inappropriate for the Commission to permit a “wires” utility to pass “commodity risk” onto its bundled service customers. Individual, low-use residential and small business customers do not have competitive options and do not have tools to allow them to manage “commodity risk.”

7) How do we expect wholesale electricity prices to behave in 2007 and beyond? Apart from their level, how volatile will they be?

In Illinois, by far the dominant fuels are nuclear and coal. For example, the ComEd environmental disclosure statement for the 12 months ending June 30, 2003, shows that 67% of its kWh were produced by nuclear plants, 28% by coal-fired generators, and just 2% using natural gas. The surplus baseload capacity which exists presently and is expected to remain for many years should indicate relatively low market prices for the vast majority of hours in the year if the wholesale market is functioning properly. To the extent that wholesale electric markets fail to become fully competitive or markets in electricity-related derivatives fail to develop, volatility could be exacerbated. On the other hand, development of demand response resources, efficiency programs and long term contracts with renewables not subject to fossil fuel price volatility, would do much to temper that volatility or protect consumers from it.

9) What will the wholesale market structure look like in 2007? What effect will the establishment of working markets in the PJM and MISO footprints have?

We expect that there will be some movement towards market structures compliant with Standard Market Design (SMD), especially with integration of NICA into PJM and Ameren into MISO. See also, discussion of PJM integration in Sec. 1.2, above.

14) Should utilities procure power for bundled customers through auctions, competitive bidding or similar acquisition processes? How should auctions, competitive bidding, or other acquisition processes be structured?

In general, we would recommend the Commission not order an auction or a competitive solicitation for the totality of BUS requirements or a firm transition date until an efficient, fully competitive market is shown to exist. Auctions can, in theory, be efficient and deliver needed services at the best available price in certain circumstances. However, this theory holds only under conditions that do not exist in the Illinois wholesale power markets -- a fully competitive market. This is especially true for base load power to be delivered in the immediate post-2006 timeframe, because of the considerable lead time required for market entry. Soliciting competitive bids raises similar concerns, although a carefully structured solicitation might provide some useful information and offers, especially if the bidders were allowed to specify delivery dates other than 1/1/2007.

We note that northern and southern Illinois may have access to different wholesale electricity markets and appear to be headed towards joining different RTOs. Hence, it is possible that the answer to this question may be different for the different regions.

15) Should power acquisition practices be structured any differently where wholesale markets are not fully competitive?

Absolutely. As discussed above, auctions or other competitive solicitations are very risky in wholesale markets that are not fully competitive. . Consumers and the utilities that will provide them with bundled service may be exposed to extreme or even abusive market power. In fact, even in markets that are presumptively competitive, market power may still exist. Even proportionally small movements in price due to partial or part-time market power can result in very expensive results.

The Commission should be satisfied that at least the following two conditions will exist before allowing bundled service rates simply to flow through to consumers a portfolio of wholesale market power prices. First, the Commission should verify that there is no reasonable prospect that wholesale generators will be able to exercise market power in Illinois wholesale power markets at any time, taking into account all the wholesale products that bundled service providers will need to purchase. Second, the Commission should examine whether existing generation combined with new supplies from *likely* market entrants will be sufficient to meet the need for both bundled and unbundled service, plus a reasonable margin. If these conditions are not met, consumers will be at severe risk and every effort should be made to find power acquisition practices that will ensure just and reasonable prices for bundled service. FERC and the ISOs entering Illinois continue to develop new proposals for market monitoring and mitigation. The Commission should investigate these proposals (as well as other proposals and measures already in place elsewhere) to assess their readiness and likely impact on Illinois markets.

For these reasons, we recommend that the Commission arrange for a thorough, independent market power assessment immediately and before committing to competitive solicitations.

16) As part of the power acquisition process, should utilities be required to file energy plans? What information should be provided? What role would this information play in ratemaking and/or prudence review of costs?

Loads cannot be served without planning. The questions are: In whose interests will the planning be conducted? What are the planning criteria? Will the planning process and its result be subject to public scrutiny and regulatory oversight? The filing of required energy plans could help to assure that there will be adequate, safe, environmentally sound power to serve bundled service (and any other customers of utilities). Energy plans filed by utilities should treat generation, transmission, and demand response or efficiency resources on an equal footing. Cogeneration, combined heat and power, and other distributed generation resources that will advance the above goals should be identified. Where they have been so identified, competitive solicitations reserved for those resources should be considered. Similarly, efficiency and demand response programs should be assessed for their ability to reduce not only power costs, but also environmental impacts, wholesale market power, and market price volatility. In addition, energy plans should analyze and report the costs, uncertainties, and environmental impacts of each option and present coordinated plans that best advance the above goals.

If energy plans are required by the Commission, their role in ratemaking or prudence review should be limited. In particular, it is important to ensure that responsibility for management and implementation of plans remain with the utility. All actions taken by utilities in providing bundled service ought to remain subject to prudence review and other, normal ratemaking protections. At most, if the Commission wished to consider issuing approvals (or disapprovals) for such energy plans, it should clearly limit the impact of that decision. For example, the regulatory impact of approval might be limited creating a rebuttable presumption that acquiring a portfolio of the general character the approved plan is prudent, but only as of the date the record is closed and only to the extent of the information in the record. Such a presumption would, naturally, not apply to implementation, ongoing management or decisions to continue pursuit of the approved plan in the face of contrary information that the utility had or should have had.

17) Utilities that do not own generation will rely on the financial and operational soundness of their suppliers. What credit and reliability requirements should be required in the acquisition process? How should we address the supplier defaults?

We understand that most ISOs, such as the New England and PJM ISO's have clear rules for assuring the credit and financial reliability of counter-parties in routine transactions. Such provisions are probably adequate for short-term transactions. Long-term contracts, especially unit contracts with renewable generators, should look little different in this regard than traditional power supply arrangements.

The primary concerns should be with two relatively new types of arrangements: long term forward contracts with marketing entities that are not physical generators and affiliate transactions between Bundled Utility Service providers and the generation or marketing arms of the utilities or their parent corporations. Arrangements with affiliates, especially those with large fractions of the region's installed capacity might need special, more rigorous treatment, such as corporate guarantees and letters of credit. Counterparty risk management with long-term forward contracts with marketing-only entities is an area of risk that is challenging due, at least in part, to the relative immaturity of electricity derivative markets. We believe that the best way to limit that risk is sound portfolio management that includes long-term contracts based on renewable energy sources.

18) What is the role of interruptible and curtailable load and energy efficiency / DSM initiatives in cost-effectively limiting the resources required? How can the market aid utilities in making these decisions?

There is a vast potential to improve the efficiency with which electricity is used. All types of electricity customers have numerous opportunities to replace aging electric equipment with newer, more efficient models, or to buy a high-efficiency product when purchasing a new piece of electric equipment.[5] There is a long and ever-growing list of new technologies to reduce electricity consumption, measures costing significantly less than generating, transmitting and distributing electricity. Thus, energy efficiency programs offer a huge potential for lowering system-wide electricity costs and reducing customers' electricity bills. Both efficiency and demand response programs, especially targeted at end uses and customers who disproportionately affect the regional peak load and near-peak load hours, can significantly reduce market clearing prices, mitigate market power, reduce congestion, and benefit program participants and non-participants, alike.

In addition to lowering electricity costs and customers' bills, energy efficiency offers a variety of benefits to utilities, their customers, and society in general.

- Energy efficiency can help reduce the risks associated with fossil fuels and their inherently unstable price and supply characteristics and avoid the costs of unanticipated increases in future fuel prices.
- Energy efficiency can reduce the risks associated with environmental impacts. By reducing a utility's environmental impacts, energy efficiency programs can help utilities and their ratepayers avoid the hard to predict costs of complying with potential future environmental regulations, such as CO2 regulation.
- Energy efficiency can improve the overall reliability of the electricity system. First, efficiency programs can have a substantial impact on peak demand, during those times when reliability is most at risk. Second, by slowing the rate of growth of electricity peak and energy demands, energy efficiency can provide utilities and generation companies more time and flexibility to respond to changing market conditions, while moderating the "boom-and-bust" effect of competitive market forces on generation supply.
- Since efficiency programs have a substantial impact on peak demand, they help reduce the stress on local transmission and distribution systems, potentially deferring expensive T&D upgrades or mitigating local transmission congestion problems.

[5] Energy efficiency as used in this report is defined as technologies, measures, activities and programs designed to reduce the amount of energy needed to provide a given electricity service (e.g., lighting, heating, refrigeration, motor power). In other words, the level of electricity service to customers is maintained or improved, while the amount of energy required is reduced.

- Energy efficiency can result in significant benefits to the environment. Every kWh saved through efficiency results in less electricity generation, and thus less pollution.[6] Energy efficiency can delay or avoid the need for new power plants or transmission lines, thereby reducing all of the environmental impacts associated with power plant or transmission line siting.
- Energy efficiency can also promote local economic development and job creation by increasing the disposable income of citizens and making businesses and industries more competitive, compared to importation of power plant equipment, fuel, or purchased power from outside the utility service territory.

The primary rationale for implementing energy efficiency -- to reduce electricity costs and lower customer bills -- is just as relevant in today's electricity industry as it has been in the past. It is just as relevant in a restructured electricity industry with retail competition as it is in state or region with fully-regulated, vertically-integrated utilities.

Furthermore, some of the other benefits of energy efficiency are even more valuable in today's electricity industry than in the past. Recent spikes in the price of natural gas and the prices of some wholesale electric markets illustrate the risk-reduction benefits of energy efficiency. Maintaining electric reliability during peak hours can be more challenging and expensive in a restructured wholesale electricity market. Concerns over the environmental impacts of the electricity industry have increased over time, and the likelihood of future carbon regulations increases with each passing year. Energy efficiency is also more valuable in a competitive wholesale market, as it can make the demand side of the market more responsive to the effects of the supply side (e.g., price spikes, volatility, market power abuse).

Portfolio management provides a methodology and a regulatory forum to obtain the many benefits of energy efficiency, regardless of the industry structure. Portfolio management explicitly recognizes that both vertically-integrated and distribution-only utilities have an essential role to play in managing the electricity resources used to serve electric customers. The management of these resources will be most efficient, and provide the greatest benefits to customers and society, if it includes *all* cost-effective resources on both the demand-side and the supply-side.

We believe that markets and ISOs or RTOs can do much to support demand response programs and make them cost effective and successful. The Commission should ensure that market managers in Illinois acknowledge an obligation to support such programs and do so intensively and proactively.

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6 Unlike other pollution control measures -- such as scrubbers or selective catalytic reduction -- energy efficiency measures can reduce air emissions with a *net reduction* in costs. Thus, energy efficiency programs should be considered as one of the top priorities when investigating options for reducing air emissions from power plants.

We also believe that the efficiency resources are most effectively acquired through comprehensive programs that have stable funding and minimize fragmentation and information barriers. An independent efficiency delivery entity funded by a system benefits charge (SBC) is probably the best way to acquire those resources. The SBC, usually a non-bypassable wires charge applied to all electricity delivered by the distribution system, should be set based on an analysis of the cost effective efficiency resources available.

19) Should utilities use financial markets to hedge their purchases for their bundled customers? How should hedging costs be recovered in utility rates? How would prudence be determined for hedging efforts and costs?

See Q. 23 for answer.

20) Should energy efficiency be deployed as a supply substitution resource? If so, how?

We do not understand the phrase "supply substitution resource." Assuming that this means either (1) energy efficiency as a cost effective alternative to generation or transmission, or (2) demand response programs for economic dispatch or reliability use, please see the answer to Q. 18.

21) Many demand reduction (DR) and energy efficiency (EE) activities show net benefits for distribution utilities, generation companies, and consumers. However, the benefits of a single DR activity are split between different market sectors. Despite the widespread benefit of DR and EE, there is no mechanism for sharing the cost of this activity across market sectors. In light of the system-wide benefits, should distribution utilities be required to consider energy efficiency and/or demand reduction procurement on the same basis as procurement of energy? What is the role of the Commission in facilitating the adoption of beneficial initiatives with these types of split incentives in the market?

Use of a SBC as described in the answer to Q. 18, places the cost on all retail consumers. Since they also receive (over time) the benefits accruing to cost of service regulated distribution and transmission providers, this is appropriate. It is an interesting question whether generators and brokers benefit from DR or EE activities, and, if so, how they should pay for those benefits. While we do not have a position on that question at this time, we look forward to considering this point further in the Initiative.

22) Should utilities be required to use a designated percentage of renewable energy as part of their supply portfolio?

Many jurisdictions, especially states with retail choice, have such a minimum renewable content requirement, often called a renewable portfolio standard (RPS). Typically, the RPS requirement applies to entities providing both competitive retail service and default or bundled service. In the context of portfolio management, which we recommend be adopted for managing Bundled Utility Service procurement, renewable resource and an RPS, in particular, can provide important benefits, particularly if used to add long term, stable resources to a BUS supply portfolio.

Most types of renewable generation have cost structures that are not influenced by fossil fuel prices and wholesale electric market prices. Wind, photovoltaic, and hydroelectric generation costs, for example, are essentially independent of fossil fuel prices. Thus, additional renewable energy supplied in or delivered to the regional market will have several beneficial effects. First, adding new renewable generation means that a greater portion of the supply being bid into the market is not affected by fossil fuel price fluctuations, moderating wholesale electric market price volatility for all customers. Second, many renewable generation technologies are not dispatchable, so they are ordinarily bid into the market at a zero price to ensure their output is purchased whenever it is available. The effect of adding to the market auction power bid at zero price is to reduce the market-clearing price for all buyers. This is because, while the market clearing price is set by the bid price of the most expensive generator actually dispatched, having zero bid generation added to the "bottom" of the market bid stack will cause the ISO to pass over expensive sources that would otherwise have been needed, causing the clearing price to be set by a lower price source. This dynamic has the beneficial side effect of mitigating the market power of suppliers, which can result in significant cost savings for all consumers in the market. In addition, to the extent that generation is added within a congested region, locational marginal pricing adders, line losses, transmission and distribution (T&D) upgrade costs, and other savings will accrue as well.

We recommend that BUS supply be served by a managed portfolio that includes a reasonable and gradually increasing fraction of energy from very long term contracts with renewable sources. This could be done through the portfolio acquisition process to maximize the long-term price stability benefits flowing through to BUS customers, through an RPS applicable to all retail electricity providers, or a combination of the two. These approaches ensure that all customers benefit from the risk mitigation benefits of renewable energy and ensure that all users of the electric system contribute to solving the problems created by producing electric power.

23) Should the utilities be required to use multiple supply sources rather rely on a single source? Should energy purchased through any of these methods be acquired in small units or in large blocks? Why?

In addressing the two preceding questions, we consider two issues as follows: (1) the assembly and management of a portfolio of power resources of varied sources, technologies, contract durations and maturities and (2) a portfolio augmented by financial instruments to further hedge and control the risk of that portfolio. These issues roughly correspond to the issues raised in Q. 23 and Q. 19.

The answer to Q. 23, regarding multiple supply sources, is a definite "yes." However, the Commission should go much further in its expectations for bundled service portfolio diversification. It is quite likely that the majority of customers, especially residential, and small commercial and industrial customers, will continue to require Bundled Utility Service well into the foreseeable future. Portfolio management provides a means for these customers to enjoy some of the benefits offered by the competitive wholesale markets, through the efforts of the portfolio manager who essentially acts as their "broker." Legislators and regulators can play a key role in ensuring that these customers are provided with reliable, low-cost electricity services at stable prices in the near-term and over the long run. Portfolio management offers the tools and techniques to achieve this important goal.

For example, recent procurement practices, particularly in areas with retail choice, overemphasize relatively short-term contracts. Many default service providers simply establish new generation contracts for short-term power every six or twelve months. This exposes customers (or, more appropriately, providers) to costs based on whatever happens to be the state of the market on a particular date each year or half-year, with the forward cost of power very strongly influenced by the level of spot market prices at the time.

If done well, portfolio management will result in lower electricity costs, lower electricity bills, and more stable electricity prices. If, instead, default service providers simply pass through the costs of short-term generation contracts, customers will be subject to higher electricity prices, greater volatility in prices, and greater risks of future cost increases.
As applied to the electricity industry, portfolio management rests on the simple notion that that active participation in electricity markets and careful choices among a variety of electricity products and resources will provide more stable service to customers over both the short- and long-term future. The key benefits of portfolio management include:

- Lower electricity costs, lower electricity bills, and more stable electricity prices, not only by purchasing more wisely for consumers' needs, but also by injecting valuable discipline into wholesale markets.
- Offering a way to shift the focus of electric utilities' or bundled utility service providers from short-term, market-driven prices to long-term customer costs and customer bills. This shift allows regulators to maintain (or reintroduce) key public policy goals into the critical function of power procurement for the large majority of electricity customers.
- Offering regulators a mechanism to promote energy efficiency, build markets for renewable generation, encourage fuel and technology diversity, and achieve environmental objectives.

In sum, portfolio management is not only consistent with competitive markets; it is, in fact, necessary to ensure that competitive wholesale markets are robust. These benefits can and should be delivered to bundled service customers, but are now being foregone in many jurisdictions, both restructured and traditional.

States have gone about procuring electricity for their default customers using several different methods. In some retail choice states, default service is procured under contracts with competitive providers who bid for the job using an RFP type process. In other states, former incumbents are mandated to provide default service from their owned resources or competitively acquired contracts. The durations of such contracts vary between states. Other contract variables include length and price of the contract, fuel (e.g., renewable vs. coal.), compensation, and cost recovery arrangements. For example, in Rhode Island, default service is competitively bid in 6-month increments, while in New Jersey, auctions are held annually. See Table 2.

Table 2: Default Term in Various States.

State	Default Term End Date	Procurement Rules for Default Service	Renewable Rules
Connecticut	2007	Contracts procured in overlapping pattern of fixed periods. The contracts must be for terms of not less than 6 months, unless shorter terms are justified.	Renewable energy portfolio requirement is applicable to the Standard Offer, but the timetable for the minimum % renewables is extended.
Maryland	Various	Utilities must attempt to obtain 1, 2, and 3 year contracts with 50% of load served through a 1-year contract.	
New Jersey	2006	Fixed price lasting 34 months for 1/3 of supply; Fixed price lasting 10 months for 2/3 of load. Single annual auction date.	
Rhode Island	2009	6 month increments	
Massachusetts	2005	50% of load is procured semiannually for 12-month terms.	No minimum standards; no requirement to enter into long-term contracts with renewable resources.
Pennsylvania	Various		20% of customers assigned to suppliers offering service with a renewable energy component of at least 5%.
Washington, DC	2006	Recommended to utilities that contract mix should include contracts of at least 3 years for no less than 40% of the total load	None

States have been exploring and experimenting with how to procure electricity for default service customers. We have identified certain best practices that, in combination, may be expected to produce a well-balanced portfolio:

- Use of laddered contracts, such as in Connecticut.
- Inclusion of a reasonable percentage of long-term contracts, such as in Washington, DC.
- Use of demand side management programs to reduce exposure to market risks, such as in Montana.

- Inclusion of long term, fixed price contracts for renewables to reduce exposure to fossil fuel prices and environmental risks, such as in Pennsylvania.
- Use of a long transition period to maximize opportunities for rational portfolio management, such as in Montana.[7]

Regarding Q. 19 on financial hedging, our fundamental position is that utilities providing bundled service must retain market management responsibility, including, but not limited to, decisions as to whether to engage in financial hedging. The particulars should not be prescribed by the Commission. It is well known that any commodity portfolio can be improved by appropriate use of hedges. Doing so is a routine management function in many industries, and we believe it is clear that a reasonable person responsible for the management of public utility service would see carefully selected and managed hedges as part of sound and economical management. On the other hand, carefully selecting and managing hedges as part of a portfolio is an inherently dynamic function, and utilities should not look to the Commission to tell them when and how to make those decisions. There are many useful financial instruments available for this task, typically traded in Chicago.

24) Should utilities be allowed to make any or all their purchases through an unregulated affiliate? Why or why not?

This practice creates significant risk of inflated costs for BUS consumers. It should not be allowed without ensuring that codes of conduct, affiliate transaction rules, and cost accounting manuals are in order for that purpose. Furthermore, any such purchases that are permitted should be subject to an affiliate transaction rule that, for BUS ratemaking purposes, prices purchases from affiliates (whether for power or for other goods and services) at the lower of book or market and sales to affiliates at the higher of book or market. Such purchases should also be subject to explicit rules requiring full access to the books and records of affiliates to verify both costs and compliance with rules and public interest and careful provisions to audit compliance with codes and rules and to recover any costs paid for bundled service that are not in compliance with those codes and rules should be included.

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7 As an example, we note that Montana, though providing for retail choice, utilizes an IRP-type approach for default service that may have some relevance to the Illinois situation. Montana follows rules that require the default supply utilities to "plan and manage its resource portfolio in order to provide adequate, reliable and efficient annual and long-term default electricity supply services at the lowest total cost." 9Rule V (38.5.8209) While green or renewable energy products can be offered, Montana does not make this a requirement. The default supply utilities are, however, required to use a portfolio approach to acquiring supply. This includes negotiating contracts of at least 10 years. In addition, demand-side management must be considered as part of the portfolio. Most interesting, perhaps, is that in Montana default supply service must be provided for a lengthy transition period that does not end until July 1, 2027, thus ensuring a long planning and acquisition horizon. To the extent that Illinois can incorporate elements of this approach to default service provision, there will be opportunities to manage cost and risk for default service customers over the long term.

25) What additional safeguards, if any, should be included in purchase agreements and intercompany operating agreements between a utility and its affiliates?

The recommendations in our answer to Q. 24 represent a minimum level of safeguards. It is clear that nobody would design a market structured like the one that exists today in this region, if the goal was efficient wholesale competition. The issue is whether any additional safeguards, such as structural separations, may be appropriate.

26) Are there barriers to efficient development of co generation and self-generation, including but not limited to projects of a size and scope to permit them to serve multiple nearby industries that should be eliminated? If so, how can they be eliminated?

We are aware of numerous barriers to development of co-generation, self-generation, and related resources such as combined heat and power (CHP) and district heating and cooling. One way to address these barriers is to adopt regulations regarding distributed resource planning and interconnection that would provide clarity to the requirement for developers and distribution utilities. In addition, the Commission should pay particular attention to the issue of barriers to small scale self-generation and CHP (*e.g.*, interconnection rules and buyback rates). As new technology emerges, small-scale self-generation may provide the best opportunity for meaningful choice of supply for residential and small commercial customers -- but only if these barriers are eliminated.

27) To what extent should preapproval/predetermination of prudence of the utility's power purchases (via RFP's, auctions, etc…) be included in utility power procurement? To what extent should preapproval/predetermination of portfolio planning be included in utility power procurement?

See answer to Q. 4.

28) In addressing power procurement issues, the Commission also needs to consider that some utilities are multi-jurisdictional, remain vertically integrated and continue to own generation. Given that generation decisions are made on a system-wide basis and that these companies may be procuring little or no power in the market for their customers, does it make sense to apply power procurement requirements to these utilities?

We strongly believe that portfolio management is a vital tool for controlling risks in public utility electric service, whether the service is provided through a vertically integrated utility or through procurement of bundled service requirements against a backdrop of retail choice. Integrated utilities that already possess sufficient generation resources to meet load are no different in this regard since they face opportunity costs for alternative dispositions of their generation that are the same as the purchase costs of utilities that are short.

There is no reason why multi-jurisdictional utilities should not be equally accountable for sound portfolio planning, acquisition and management on behalf of their Illinois jurisdictional customers.

2.2 Rate Issues

While we offer a few comments on selected ratemaking issues in this section, our main point is that it is premature to take up those issues. Specifically, we believe that:

- ratemaking issues logically follow Power Procurement and Competitive Issues others; we recommend the Commission bifurcate its consideration of issues, taking up rate issues and some others at a later date;
- the Commission and parties need to focus on fact that there are no credible retail providers in state and the threat posed by the existence of extreme market concentration in northern Illinois;
- that before issuing a solicitation or any other directives concerning power procurement, there should be an independent assessment of market power in the Illinois wholesale electricity markets;[8]
- that after careful evaluation of the threats posed by market power in those markets, next steps on Power Procurement and Competitive issues, depending on the study findings, could include the following range of options:
    - proceeding with competitive procurement subject to appropriate portfolio management standards;
    - proceeding with competitive procurement subject to appropriate portfolio management standards subject to special backstops and safeguards against market power, such as imposed prices for purchases from affiliates;
    - a further transition period with cost based rates; or
    - enactment of new rules or legislation to establish a reasonable regime for post-2006 that takes the realities of the market into account and combines the above options over time
- that the Commission and the parties should examine how integration into PJM and other RTOs or ISOs would affect market power; and
- that there be a thorough review and reconsideration of existing affiliate rules with regard to their fitness to protect consumers during further transitions and the post-transition period.

[8] CCC would be willing to outline that analysis for Commission's consideration.

31) Should rates be determined, and shown on the tariff sheets, for both bundled and delivery services, as individual rate components, in a manner such as: customer charge, meter charge, distribution delivery charge, transmission delivery charge, and supply charge? If so, should there be a single proceeding to reset the delivery component that would apply to both bundled rates and delivery service?

These proposals are secondary to the threshold issues we discuss in subsection 2.1. We recommend that the Commission defer this action. However, we acknowledge that some changes in billing practices for bundled service customers would be appropriate when the need arises and customer benefits from such changes can be shown . We are concerned that providing customers with information they cannot use (nor readily understand) is counterproductive and will engender negative views of restructuring. The Commission must be sensitive to the reasonable skepticism of consumers about this entire enterprise, and should avoid billing changes that will lead to confusion and therefore to increased consumer vulnerability to abuse. In addition, any such "unbundled bills" for BUS customers, should be considered only in the context of a carefully designed and well funded consumer education campaign.

32) Should each utility have the same customer classes for both bundled and unbundled customer?

The important thing -- assuming retail choice is a realistic option -- is for consumer clarity in shopping and choosing to return to bundled service. It may reduce consumer confusion and facilitate choice somewhat if these classes were identical, but we believe this will not be a major determining factor in the level of shopping. However, consumer service and satisfaction could be materially impacted if any differences were obscure or hard to justify or discriminated against some class of customers. On the whole, so long as it is clear what charges and terms and conditions will be faced moving in either direction, so long as those charges, terms and conditions are just and reasonable and not unduly discriminatory, this distinction is not likely to be critical.

33) Should rates be reset on a monthly or yearly basis or should rates be fixed for a multi-year period? Or, should an assortment of these products be made available?

Setting rates for multi-year periods would be desirable if it did not create a buildup of unrecovered or over-recovered costs. We do not support monthly adjustments as they are generally perceived as undesirable by consumers and make it difficult for them to budget. An argument could be made for either annual adjustments or for rate setting on an as-needed basis.

34) To what extent should non-competitive tariffed energy service offerings by utilities be hedged against fuel price/ market price risks? Should utilities attempt to hedge for their full expected load serving obligation, or only for a portion? For how long should prices be hedged?

In general, such hedging is desirable. See answer to Q. 23. As discussed in the introduction to this subsection, there are important threshold questions that should be addressed before developing specific answers to this question. However, we would observe at this time that acquiring needed supplies of power for BUS as a managed portfolio, for example in laddered segments, would reduce volatility and risk exposure.

35) Should the type or extent of hedging be different for different classes of customers? For example, is the need for hedging less for customers who have greatest direct access to competitive markets?

While this idea has some theoretical appeal, we believe that customers who remain on BUS are entitled to service from a properly managed portfolio regardless of what class they belong to or how much actual competition there is to serve that class. Of particular concern is the risk that customers in classes with significant existing retail options might arbitrage their purchases in a way that increases costs to other customers taking bundled utility service.

36) How should hedging costs be recovered in utility rates? How should prudence for hedging efforts and costs be assessed?

We believe that such costs should be treated in the same way as any other power procurement costs are treated in traditional utility ratemaking. The standard of prudence for hedging activities should, in principle, be no different from the usual standard.

38) How can the costs of providing tariffed non-competitive energy service best be recovered by utilities? Should rates simply be fixed at levels that are forecast to recover utility costs? Alternatively, should rates be based on a relatively current measure of market value and perhaps be reset frequently. Should new market value estimation methods be developed if rates are to be based on market indices? What, if any, are the uses for the Neutral Fact Finder processes in the post-2006 period?

We recommend (1) against very frequent rate adjustments and (2) for basing rates on costs rather than a market index. The intent of PM is to reduce volatility and price spikes relative to the market. If that's achieved, the benefits should flow through to consumers. But it is important to note that the options being described in this question -- fixed rates, or alternatively, indexed rates -- are forms of alternative regulation, which are allowed under current law. Utilities may propose these sorts of rates and the Commission may approve them subject to the requirements of Illinois law.

40) If utilities are required or permitted to take actions to reduce price risk or the volatility of their costs, how should these costs be recovered?

See answer to Q. 36.

41) Rate design issues can also have significant competitive implications. Unless rates are designed to send correct price signals, economically efficient consumption decisions and economically efficient competition will not necessarily result. How can decisions about the method of recovery of production costs and the allocation of those costs among rates and customers be made in a manner likely to promote efficiency, and efficient competition between providers and resources?

We agree that rate design issues can have competitive implications. They can -- and do -- also have important non-competitive implications. Restructuring provides the opportunity for new programs that can promote more efficient consumption without burdening all customers with "correct price signals," which at a minimum require new metering as well as new ways of thinking about electricity usage and new lifestyle patterns.

While often not favored by consumers, seasonal rates are generally economically efficient and preferred, from a policy perspective, for rate classes where material cost differentials exist between seasons or if fixed costs are strongly dependent on radically different seasonal loads. Such differentials can arise from seasonal variations in marginal costs or market clearing prices, such as for energy, or from seasonal variations in load that require additional capital invest. On the other hand, many consumers find seasonal rates hard to understand or frustrating. Utilities also may need to modify meter reading and billing procedures. The relative balance between the advantages and disadvantages of seasonal rates depend on a factual assessment of these issues for each potentially affected class. It is not necessary to have the same outcome for all classes. We recommend the Commission consider establishing seasonal rates, but as mentioned above, believe there are important threshold issues that need to be addressed first. Further, the value of seasonal or time of use rates, of course, depends on setting the prices in a meaningful manner, such that customers with time-varying load perceive cost impacts that are not artificially dampened.[9]

Some seasonal variations exist in Illinois rates today. However, the modest price signals sent by these rates have not resulted in significant improvement in load shapes. Even when seasonal variations were pronounced, such as during the mid-80s, when the residential tail block in ComEd's territory was set at more than 50% above today's rate, the result was not what was intended. Instead of

[9] Seasonal differentials in rates that are driven by commodity costs (rather than fixed costs) should reflect the cost differentials of the portfolio, not the market, so that the benefits of reduced seasonal volatility in the portfolio continue to flow through to consumers.

reduced peaks, we saw “needle peaking” and significant consumer confusion and anger over high summer bills.

Considerable savings can be achieved through optional utility-provided programs that provide opportunities for material savings and consumer convenience. Rate options including seasonality, and TOU or even real-time pricing are effective tools for improving the load shape of bundled service customers. Programs such as ComEd’s “Nature First”, which provides discounts to a limited number of residential consumers who are willing to have their air-conditioning cycled on and off in peak periods can be both popular and effective. The experiment in real-time rates for residential customers, conducted by the Energy Co-op, has shown real potential for responsiveness to price signals by a self-selected customer group. These types of programs not only provide benefits to participating customers, but by improving the load shape of the class and reducing peak demand, they can have significant effects on the prices of power in wholesale markets, thus saving money for both participants and non-participants. Also, they provide choice to consumers within the context of the Bundled Utility Service provider. However, the choice of traditional bundled service using the installed kWh meter should also remain a choice for those who want to retain it, with traditional average cost pricing for residential and small business customers.

43) Should some or all customer rates reflect market indices? How would costs be recovered if some rates were to reflect market indices? Should new market value estimation methods be developed if rates are to be based on market indices? What are the uses, if any, for the Neutral Fact Finder processes in the post-2006 period?

See answer to Q. 31.

46) Can or should rates be restructured to eliminate inter- and intra-class subsidies in existing bundled rates?

47) Should “special rates” (e.g., space heating, lighting) be maintained?

In general, special rates should be phased out unless they represent socially desirable end uses and are clearly different in their cost structures. It would not make sense to end street lighting tariffs, but space heating is probably not desirable. Innovative rate designs aimed at improving load shapes or achieving other shared social goods could also be considered.

48) Should charges be restructured to more accurately reflect the costs of providing delivery and customer services that do not vary significantly based on the kilowatt-hours consumed (e.g., standby service rates)?

For normal retail customers, traditional rate design principles are adequate and well tested. For self-generators and distributed generation customers, carefully designed standby rates are appropriate, so long as they do not improperly discourage development of those resources.

49) Should some or all rates for some or all of the rate classes be determined on a seasonal basis?

See answer to Q.41.

50) Should rates for customers who return to bundled service be different from the rates offered to basic bundled service customers? Do customers who move back and forth between bundled services and delivery services cause additional costs that should be charged only to those customers?[10]

Traditional principles of cost causation should guide the ultimate decision on this issue, but it would be counterproductive to use BUS rate design punitively against any class of customers.

52) How should costs related to energy efficiency and demand reduction be charged in rates?

See answers to Q. 18 and Q. 21

53) How should costs for obtaining renewable energy be charged in rates?

Except for any portion of an SBC dedicated to supporting renewable energy development, these costs should be treated in the same manner as any other power costs.

54) What new rates or services, if any, should utilities offer (e.g., green power options)? What kind of rate structures support efficiency? Time of Use rates for business and residential customer classes? Amending of declining block rate structures so that the first block of kWhs on a customer bill are the cheapest kWhs, and the additional kWhs are more expensive?

The suggestion for inclining (increasing) block rates is interesting given the sometimes steeply increasing price curve for supply, especially in peak periods. Regarding green power options, see answer to Q.22.

55) Should there be an interruptible rate option for transmission and distribution services and/or generation services? How should such a rate be designed?

Optional interruptible rates are generally economically efficient and preferred from a policy perspective for any rate classes where material daily, weekly or sporadic capacity constraints or market price differentials exist. See also, answer to Q.41.

For certain industrial loads, fuel switching or cutbacks in usage are feasible and can create significant savings for the customer and the utility. However, such interruptible options or demand response programs require careful planning, marketing, and infrastructure development.

For smaller customers, interruptible rates can be effective, mainly in two situations. First, private entrepreneurs may be able to aggregate substantial amounts of load in small commercial or even residential sectors and manage them for demand response or energy price savings. The New England ISO's demand response programs support this function as well as large customers participating as individuals. Other small customers can participate in interruptible rates through direct load control for water heating, electric space heating (especially storage space heating) and air conditioning loads. See, for example, the ComEd Nature First program, mentioned above. Utilities also may need to modify metering, meter reading, and billing procedures. The relative balance between the advantages and disadvantages of interruptible rates depend on a factual assessment of these issues for each potentially affected class. It is not likely that there will be the same outcome for all classes.

56) Should utilities be required to demonstrate consideration of energy efficiency, demand reduction, and distributed generation strategies as part of any proposal for new distribution and/or transmission facilities?

Distributed utility planning (DUP) is a sound means of ensuring that infrastructure investments are cost effective. We recommend, at a minimum, that such a showing be made as a condition of permitting major transmission or distribution investments. (The definition of "major" could be based on size of investment, facility voltage, type of facility, i.e., lines vs. substations, or other factors.) However, systematic DUP carried out in advance so that transmission and distribution constraints are identified soon enough so that alternatives can actually be mobilized in a timely manner is preferable to just having permit conditions.

58) Should existing real-time tariffs be modified to encourage customer interest in such tariffs? If so, what modifications are necessary?

See answer to Q.41.

59) In the IDC model, the marketing of services by a distribution utility is significantly limited. How does this impact the offering of new rate structures or services, such as real-time pricing, which bring system benefits but which are unfamiliar to consumers and require education and marketing to be successful?

The Commission correctly observes that novel services, however beneficial to customers and society, often need extensive consumer education. If there is a concern that marketing activities by IDCs will be used to improperly discourage retail competition, the Commission could exercise oversight of the marketing and education plans for those services. This should not be allowed to become a barrier to successful delivery of otherwise appropriate services.

60) **What level of reward (or opportunity) is appropriate for a distribution company who purchases "safety net" service for customers? What level of power procurement risk is appropriate for distribution companies?**

We are unsure of the meaning of "safety net" service. If this refers to bundled service, see answer to Q. 36.

61) **Should Integrated Distribution Company (IDC) rules be changed to provide the option to promote green power, real-time pricing tariffs, curtailable rate options, etc..., by the distribution company?**

See answer to Q.22.

62) **How should the cost of power to be included in rates be determined for those non-Integrated Distribution Company (IDC) utilities that continue to own generation? Should it be priced at company cost, at market rates, or on some other basis?**

We are unsure of the intent of this question. If it concerns treatment of the costs of resources procured for bundled service, see answer to Q. 36.

65) **Should the requirements related to approval of alternative regulation plans be revisited with a goal of setting forth more realistic requirements so such plans could actually be implemented?**

The current law's provisions for alternative regulation approval conditions are realistic. PBR is allowed, provided the utility can demonstrate certain benefits to consumers. Such plans have actually been implemented. However, there are allegations that some utilities have abused PBR programs to the detriment of ratepayers. If the requirements are to be changed to be more favorable to utilities, as this question implies, then we would seek to remove the unilateral ability for utilities to reject a Commission order of an alternative regulation plan.

66) **Should incentives be put in place to encourage consumers to make their demands more price-responsive? What form might such incentives take?**

Yes. See answers to Q. 16, Q. 18, Q. 21, and Q. 55.

2.3 Competitive Issues

67) **What measures should the Commission undertake to encourage competition for smaller-use customers? To what extent, if at all, must the rates for non-competitive tariffed energy services to such customers be increased to permit such competition?**

The idea of increasing BUS rates in order to promote customers leaving it is abhorrent. The idea of increasing rates to promote competition must be rejected out of hand. It does small-use customers no favor to penalize them for not shopping in a market where there are no retail providers willing to serve them and questionable competitive wholesale markets for potential retail providers to function in. Nor is it appropriate for regulators to attempt to lure retailers into the market by providing them with artificial “headroom” at customers’ expense. The Commission is legally obligated to ensure that customers are charged just and reasonable bundled service rates. The goal of any change to procurement mechanisms or requirements must be a demonstrable public benefit from competition, not the promotion of retail markets for their own sake.

70) What barriers to participation in the market can and should be removed?

See answer to Q. 67.

71) Should regulations regarding codes of conduct and utility-affiliate activities be modified?

See subsection 1.3, above, and answers to Q. 3 and Q. 24.

73) What further progress can be made towards uniform tariffs?

Uniform tariff structures, terms and conditions, and formats across utilities can simplify administration, including reporting systems, possibly enable economies of scale in data systems, metering and meter reading, dispute resolution and other customer service functions. However, this is an area that should be tabled while the issues of competitiveness and power procurement for bundled service are resolved.

74) Are there specific actions the Commission can take, either through the FERC or other national or regional forums, to improve the competitiveness of the Illinois wholesale market, either through improvements in transmission availability or through better market design?

Absolutely. The Commission can and should be very involved in improving the “Illinois wholesale market” (and the broader regional markets in which Illinois is located). If wholesale electricity prices are not reasonable as a result of insufficient competition, the absence of regulation, or both, then the total prices paid by retail customers will be unreasonable, no matter how the details of retail bundled service are designed. The ICC and others representing Illinois interests should be actively involved in FERC proceedings and the PJM and MISO stakeholder processes to develop and promote effective market power analysis, monitoring and mitigation measures. The two specific possibilities mentioned in the question -- improvements in transmission availability and better market design -- can be important. But the development and application of effective market power analysis, monitoring and mitigation measures will likely be even more important in terms of ensuring that electricity prices paid by customers in Illinois are just and reasonable. These issues are also discussed in Section 1.

75) Is providing competitively priced wholesale power for small-use customers enough to meet the "benefits" and "equity" directive in the '97 Law? (Rather than focusing on retail competition)

No. See Section 1 and the answer to Q. 67.

76) Should retail competition be encouraged if bundled use customers reap benefits through wholesale competition?

See answer to Q.67. In addition, retail competition can clearly pose significant risks and costs, especially for small customers. As stated above, if properly planned and managed portfolios can deliver the benefits of wholesale competition to retail customers, the additional costs and risks for retail competition are not justified.

77) Should the regulatory regime create rules for LDC's to provide competitively priced power to individual customers?

LDC is a term usually applied to natural gas utilities. We assume that this question refers to IDC's. If so, the question seems to be asking if regulated utilities should be encouraged to function as competitive retail providers. We believe that this is not appropriate. If there is not a functioning competitive retail market, allowing IDC's to sell market priced retail power would likely prevent the emergence of competition or, at best, require extensive market monitoring and oversight. Conversely, if there is a functioning competitive retail market, IDCs need not and should not enter that business. The transition law provides for the Power Purchase Option to be provided by the utility to non-residential customers as long as the customer is required to pay transition charges. No further PPO is necessary after the transition period if the utility's portfolio is appropriately managed and retail markets are open.

78) How should residential choice be addressed (including to a certain degree whether true "choice" itself at the residential level is an appropriate goal)?

See answer to Q. 76.

79) What are the barriers to competitive providers providing demand response programs and/or dynamic pricing offers and what can FERC and/or the Commission do to address such?

We believe that such offers are quite feasible under ordinary ISO market structures if the ISO supports their delivery. The Commission should have considerable influence to encourage this and should exercise that influence. Typically, the ISO establishes one or several programs under which it will acquire demand response resources and those resources are delivered (offered to the ISO) by customers, third party aggregators/load managers, or LSEs, as appropriate.

2.4 Utility Service Obligations After 2006

80) What should be the nature of utilities' regulated load serving obligations after 2006? Should there continue to be any obligation for the utility to offer a regulated commodity or "POLR" product? If so, to which customer classes? And, if so, should it be offered on a bundled or unbundled basis?

Given the state of retail competition in Illinois, especially for small consumers, and the market dominance that exists in the wholesale markets, the existing bundled utility service should be continued indefinitely. In fact the law requires it. Since that service should be served by a managed resource portfolio, as explained above, a public service entity should be selected to provide BUS. We are not aware of any reason that the IDCs or utilities would not be the best choice for that function, and the law would need o be changed to absolve them of that responsibility or to allow others to bid on it. We do not accept the use of the acronym POLR for service to small volume customers. Instead we propose that the Commission adopt the more accurate and less perjorative acronym, BUS – Bundled Utility Service.

81) What if the incumbent does not wish to retain the default service responsibility? Is an alternative arrangement feasible, given the incumbent's distribution monopoly and obligation to operate the system reliably (even if there are supply imbalances)?

It is possible to bid out the function of providing BUS in addition to bidding out the provision of the generation service needed. However, we do not believe the extra complications involved in doing so are warranted, especially at the same time as managing the post-2006 transition and the problems with wholesale market power in Illinois. And as stated above, we see no allowance for this idea in current law.

82) Is electric service to additional classes of customers likely to be competitive after 2006? Will the provision of electric power and energy continue to be competitive in some territories and not in others?

This question is largely predictive, not prescriptive. We believe that a very large fraction of small customers, if not all, are likely to remain on BUS for the indefinite future. However, .large C&I retail service can become more competitive over time in all service territories, and interference or prevention of such competition should not be allowed.

83) Regulation of rates for tariffed electric services has traditionally been on a cost-of-service basis. Only the telecommunications markets, with mandated retail competition structures, have been deemed sufficiently competitive for price cap regulation. What criteria will be used to determine the sufficiency of competition?

This is a complex and controversial question, requiring a high degree of speculation.. We believe that the threshold issue is whether Illinois has sufficiently competitive wholesale electricity markets and what should be done to assure that bundled service is priced at just and reasonable rates. The Commission has the authority to approve price cap regulation if the utility can demonstrate its superiority to cost-based regulation, and the utility may reject or accept an order of the Commission modifying a proposal of the utility. The telecommunications industry is characterized by rapidly declining costs, a high degree of ongoing technological innovation, and growing retail competition at all levels. None of these are descriptive of the electric industry. In our view, pure price cap regulation is unlikely to be a superior way of regulating the Illinois electric industry.

84) Should utilities offer services at long-term (a year or longer) fixed prices? Or should at least the power and energy prices vary with the market? If the latter, what is the appropriate time step for adjusting the price?

Small retail customers are generally uncomfortable with and financially stressed by frequent rate changes or changes on short notice. Rates should be set for some reasonable period of time, perhaps one year at a minimum. Sound portfolio management should minimize the need for frequent rate changes.

85) Should different POLR choices be offered to different classes of customers?

This is a detail question that should await resolution of the threshold issues we have identified above.

86) Should POLR offerings be uniform by customer class across the state? If utilities are in different situations with respect to RTOs and organized markets, should that affect the POLR choice?

This is a detail question that should await resolution of the threshold issues we have identified above. In general and subject to examining the particulars, it is reasonable to expect that RTO differences (and physical load, grid, and generation fleet differences) may lead to some need for variation among BUS offerings. However, to the extent that SMD is implemented consistently across RTOs and ISOs, this will be less of an issue.

87) If utilities offer a fixed price commodity POLR offering, how should the price be set? What role should the ICC have in overseeing the supply arrangements that the utility enters into to provide supply for such a service offering?

In general, we see no reason why BUS should not be priced at rates set by the ICC consistent under traditional ratemaking authority. As to oversight of procurement decisions, see the answer to Q. 16.

88) If utilities offer a variable price commodity POLR offering, how should the price be set? What role should the ICC have in overseeing the supply arrangements that the utility enters into for such a service? In particular, under a variable POLR pricing policy, should the ICC set requirements for how much the utility can and should rely on the shorter term market to provide such resources?

See the answer to Q. 87.

2.5 Energy Assistance

90) How should state energy assistance programs be provided for low-income customers who cannot afford to pay just and reasonable rates?

There is a wide variety of low-income energy assistance program models that could be reviewed ranging from percentage of income programs (PIP) to lifeline rates and general revenue funded support. The Commission may wish to consider a separate investigation, as this issue is likely to be readily separable from the post-2006 transition issues.

92) Are there other regulatory and/or legislative mechanisms that should be considered?

See the answer to Q. 90.

3. Conclusion

There are important unresolved issues in each of the areas of competition, procurement, retail service, energy assistance, and retail rates. While each of these issues is important, CCC believes that to protect consumers, we must resolve issues around the wholesale market and methods of procurement first. CCC is particularly concerned that the regional whole sale electricity markets are subject to poorly understood and likely severe market power with great potential for harm to present and future Bundled Utility Service customers. The potential for harm would be particularly great if BUS resources were procured in a way that simply took the market price for short-term contracts and passed that through to ratepayers. We recommend carefully designed and monitored portfolio management be required for BUS procurement, but do not view that, in itself, as sufficient to protect consumers and to assure just and reasonable rates under present wholesale market conditions.