UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Ameren Corporation	)	
Dynegy Inc.	)	
Illinova Corporation	)	**Docket No. EC04-___-000**
Illinova Generating Company	)	
Illinois Power Company	)	
	)	

PREPARED DIRECT TESTIMONY OF
RODNEY FRAME

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Rodney Frame. I am a Principal with Analysis Group, Inc. (Analysis Group).

Q. WHAT IS YOUR BUSINESS ADDRESS?

A. My business address is 1747 Pennsylvania Avenue, N.W., Suite 250, Washington, DC 20006.

Q. WHAT IS ANALYSIS GROUP?

A. Analysis Group is a consulting firm that provides microeconomic, financial and strategy services. We have offices in Boston MA, Washington DC, New York City, Denver CO, Dallas TX, Montreal, and Los Angeles, Menlo Park and San Francisco CA. We have approximately 300 employees.

Q. WHAT IS YOUR FORMAL EDUCATIONAL BACKGROUND?

A. I received a bachelors degree in business from George Washington University in Washington, DC. Also at George Washington, I completed all requirements for my Ph.D. in Economics with the exception of my thesis. My graduate studies at

George Washington were funded under the National Science Foundation Graduate Traineeship program.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have been employed by Analysis Group since January 1998. Prior to my affiliation with Analysis Group, I was a Vice President at National Economic Research Associates, Inc., where I was employed from 1984 to January 1998. Most of my work in the last several years has involved consulting with electricity industry clients on a variety of competition-related matters including retail competition and restructuring issues, wholesale bulk power markets and competition, transmission access and pricing, mergers and acquisitions and contracting for generation supplies from nonutility suppliers. I frequently address market power concerns in my work. I have testified on numerous occasions on these and related topics, before the Federal Energy Regulatory Commission (Commission), state regulatory commissions, federal and local courts and the Commerce Commission of New Zealand. From 1976 to 1984 I was a Senior Economist with Transcomm, Inc. in Falls Church, VA. There I directed a number of projects concerning market structure and ratemaking in the telecommunications industry, competition among electric utilities and postal ratemaking. Prior to my affiliation with Transcomm, I worked as an independent economic consultant advising clients mostly on telecommunications issues.

A copy of my résumé is included as Attachment 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Dynegy Inc. (Dynegy), the indirect parent of Illinois Power Company (Illinois Power), Illinova Corporation (Illinova), an indirect subsidiary of Dynegy, Illinova Generating Company (IGC), an indirect subsidiary of Dynegy, and Ameren Corporation (Ameren)[1] have reached an agreement whereby Ameren will acquire

[1] I use Ameren herein to refer to Ameren Corporation and all of its affiliates. A variety of abbreviations are used in this testimony. They are identified in Attachment 2.

all of Illinova's interest in Illinois Power and the 20 percent ownership interest in Electric Energy, Inc. (EEInc), an exempt wholesale generator, held by IGC.[2] EEInc owns and operates a 1,014 MW coal-fired generation station in Joppa, IL (Joppa steam station) and, through its Midwest Electric Power, Inc. (MEP) affiliate, two 37 MW (summer rating) combustion turbine generators (CTs), referred to herein as the 6B project. Through MEP, EEInc also operates three other CTs (162 MW total summer capacity), referred to herein as the 7B project, that are owned by Ameren. Ameren currently is the majority owner of EEInc, holding a 60 percent share. LG&E Energy (LGEE) owns the remaining 20 percent.[3] Other than the 218 MW of generation capacity associated with Dynegy's 20 percent EEInc interest,[4] the only generation capacity that is included as part of the transaction are three small generators (the State Farm diesels, with total capacity of only 5.25 MW) that are jointly-owned by Illinois Power and one of its retail customers, and that are dispatched by Illinois Power only to meet load on its system. I refer herein to Ameren's acquisition of all of Illinova's interest in Illinois Power and Dynegy's 20 percent interest in EEInc as the "proposed transaction." I have been asked by Ameren, Dynegy and Illinois Power, collectively referred to as "Applicants," to provide a competitive assessment of the proposed transaction, including the Competitive Analysis Screen that is described in Appendix A of Order No. 592, the Commission's Merger Policy Statement,[5] and in Order No. 642, Revised Filing Requirements Under Part 33 of the Commission's Regulations.[6]

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2 Throughout this testimony, I refer to generation owned by any of Dynegy's subsidiaries, including IGC, as Dynegy's generation.

3 LGEE is a subsidiary of E.ON AG, a German firm. The actual shares in EEInc are held by LGEE's Kentucky Utilities (KU) subsidiary. Throughout this testimony I refer to KU's interest in EEInc as LGEE's interest.

4 The 218 MW amount consists of 203 MW from the Joppa steam station and 15 MW from the 6B project.

5 Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 77 FERC ¶ 61,263, issued December 18, 1996 (Merger Policy Statement).

6 Revised Filing Requirements Under Part 33 of the Commission's Regulations, Final Rule in Docket No. RM 98-4-000, Order No. 642, 93 FERC ¶ 61,164, issued November 15, 2000 (Order 642).

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Section II summarizes my analysis and conclusions. Section III provides a brief overview of the features of Applicants' business activities that are most relevant for an assessment of competitive issues. Section IV discusses the relevant product and geographic markets that should be considered in assessing the competitive effects of the proposed transaction and describes the Appendix A Competitive Analysis Screen. Section V discusses the data sources and methods used for the Competitive Analysis Screen while Section VI discusses and summarizes the results. Section VII addresses potential vertical market concerns. Section VIII describes and assesses the appropriateness of the mitigation measures that have been proposed by Ameren as conditions for approval of the proposed transaction if the limited "screen violations" identified herein are deemed to represent real transaction-related competitive problems, notwithstanding that the key generation-related component of the transaction is only to increase Ameren's share in a jointly-owned generation entity of which Ameren *already* is the majority owner. Section IX provides my conclusion. The data and computer models used in my analysis are included in workpapers, which are provided on compact disks. These workpapers include the portion of the data required to be submitted by Section 33.3(d) of the Commission's regulations that are either inputs into or interim or final outputs of my analyses.

II. SUMMARY AND CONCLUSIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR ANALYSIS?

A. My testimony assesses the competitive effects of Ameren's proposed acquisition of all of Illinova's interest in Illinois Power and Dynegy's 20 percent interest in EEInc. Because, as discussed below, the transaction does not appear to result in any increase in Ameren's operational control of generation under the procedures used for the Competitive Analysis Screen of Appendix A of the Commission's Merger Policy Statement, it is not apparent that it is either necessary or appropriate to conduct such an analysis to assess the effects of the transaction on short-term and non-firm energy markets. However, there will be a change in market concentration if the analysis assigns generation capacity to market participants based upon output rights rather than operational control, and so I have used the Competitive Analysis Screen on that basis to examine the effects of the proposed transaction on short-term and non-firm energy markets. I also consider whether the transaction will have an adverse effect on competition to supply short-term capacity and long-term capacity, where one year is the length of time that divides the two. As concerns the latter, examinations of market power in long-term capacity markets generally focus upon perceived entry barriers. Because, on a post-transaction basis, Ameren will not have the ability to erect barriers to others that might compete with it in the construction of new generation capacity, I conclude that the transaction will not have an adverse effect on competition to supply long-term capacity. As concerns short-term capacity, the proposed transaction will reduce market concentration because it will result in the transfer of a small amount of generation capacity from the "bucket" of an entity that has a greater amount of uncommitted generating capacity (Dynegy) to the bucket of an entity that has a much smaller amount (Ameren). For this reason, the effect of the proposed transaction on short-term capacity markets is pro-competitive.

I do *not* include an analysis of the effects of the proposed transaction on markets for ancillary services, e.g., operating reserves (spinning and non-spinning), regulation and imbalance energy. The necessary data for such an analysis, among other things, include the ramping rates of individual generators. These data generally are not available from public sources. Under Order No. 642, separate analyses for ancillary services markets are not required if the necessary data are not publicly available. While I do not include a specific analysis, I would not expect the effects of the proposed transaction on ancillary services markets to be significant in any case, given the relatively small amount of generation capacity that Ameren will be acquiring, and given the fact that other market participants have not historically relied upon either Ameren or EEInc for these services. Moreover, because Dynegy will continue to be a potential supplier of ancillary services, the proposed transaction does not eliminate any potential suppliers of ancillary services from the market.

To perform the Appendix A Competitive Analysis Screen that is used to examine the effects of the proposed transaction on non-firm and short-term energy markets, on the assumption that EEInc's generation would be assigned to market participants based on contractual output rights, I assembled available data concerning generator costs and other characteristics, load levels by time period, market prices, transmission prices and losses (both for existing single system and regional tariffs) and transmission capacities between various destination market control areas including those operated by Ameren, Illinois Power and interconnected utilities.

My Appendix A analyses define relevant geographic markets under three different perspectives. I refer to these different perspectives as *Pre-2006*, *Post-2005* and *USEC Load*. Examining these different perspectives allows the analysis to take into account changes in the disposition of the output from Dynegy's 20 percent interest in the Joppa steam station and the unique characteristics of the EEInc control area.

The first two of these perspectives (Pre-2006 and Post-2005) focus on individual control area destination markets in accordance with the Commission's requirements for Appendix A analyses. The Pre-2006 perspective is most relevant for the time period through December 31, 2005 while existing arrangements for the disposition of the output from the Joppa steam station still are in effect. Under these existing arrangements, the output from the Joppa steam station is moved to the control areas of the respective owning parties under long-term "grandfathered" transmission arrangements.

Beginning the later of January 1, 2005 and the closing of the transaction, a portion of Illinois Power's load post-transaction will be served by Dynegy's generation under a Power Purchase Agreement (PPA) and "Memorandum PPA." Because Dynegy, not Ameren, will have operational control over the generating units used to meet that load obligation, in my Pre-2006 analysis I appropriately do not move any generation from the Dynegy bucket to the Ameren bucket on account of the PPA and Memorandum PPA. Illinois Power now has operational control over the generating units that are owned by Dynegy and used to meet the Illinois Power retail load. Dynegy will assume operational control over those generating units immediately after the closing of the proposed transaction. It is my understanding that, if the transaction closes prior to January 1, 2005, interim arrangements will be implemented through an "Interim PPA Rider" such that, while Illinois Power (which at that point will be owned by Ameren) will have physical control over the dispatch of those units, except as needed to ensure grid reliability, it will be Dynegy and not Illinois Power (or Ameren) that determines which units are dispatched, when they are dispatched and how intensively they are dispatched.

I have truncated the Pre-2006 analysis to focus only upon those individual control area destination markets where the concentration effects of the transaction are likely to be greatest. If the transaction passes muster in those control area destination markets, which turns out to be the case, one can be assured that it also will pass muster in other control area destination markets where the concentration effects are much less. As I explain below, I appropriately limit my Pre-2006 analysis to the Ameren,[7] CILCO, Commonwealth Edison Company (ComEd), Illinois Power, the City of Springfield, IL Water Light and Power Department (CWLP) and Southern Illinois Power Cooperative (SIPCO) control area destination markets. As discussed below, examining these markets is sufficient to give an accurate depiction of the transaction's effect on market concentration in an Appendix A analysis.

[7] As discussed below, Ameren is the parent of three public utility operating companies, Union Electric Company (AmerenUE), Central Illinois Public Service Company (AmerenCIPS) and Central Illinois Light Company (AmerenCILCO). AmerenUE and AmerenCIPS are located in one control area while AmerenCILCO is located in a separate control area. I refer to the former as the "Ameren control area" and the latter as the "CILCO control area."

The need for the second (Post-2005) perspective is suggested principally by the December 31, 2005 expiration of existing arrangements whereby the output from the Joppa steam station is moved to the control areas of the respective owning parties. After December 31, 2005, there no longer will be any obvious logical support for assigning Dynegy's Joppa steam station interest to the Illinois Power control area as is done in the Pre-2006 analysis. My assumption is that, at that point, Ameren will market its portion of the Joppa steam station output wherever it will yield the best price and other terms and conditions. The geographic market in which the output could be marketed at that point is likely to be broad. For purposes of the Appendix A analysis, one possibility would be to model the EEInc generation facilities as part of the EEInc control area and treat them the same as any other generation capacity, meaning that they must bear transmission prices and losses, and face transmission system limits, in order to be marketed in remote control areas. However, because the interconnection between EEInc and Ameren is very strong in relationship to the amount of generation in the EEInc control area, for modeling purposes for the Post-2005 analysis I have assumed that *all* of Ameren's and Dynegy's Joppa steam and 6B interests are located in the Ameren control area and therefore do not have to face transmission constraints to deliver output there.[8] Placing this capacity in the Ameren control area is a conservative assumption that tends to increase the measured HHI changes from the transaction in the Ameren control area. I examine the same six destination markets for my Post-2005 analysis as for my Pre-2006 analysis.

I appropriately do not examine the effects of the proposed transaction on concentration in the EEInc control area in either the Pre-2006 or Post-2005 analyses because of the special characteristics of that control area. The limited load that can be directly served by the EEInc control area—that of the United States Enrichment Corporation's (USEC) Paducah Gaseous Diffusion Plant

[8] I treat LGEE's interests in the Joppa steam station and the 6B project the same in the Post-2005 analyses as I do in the Pre-2006 analyses, and move them to the LGEE control area.

(PGDP)—actually can be served *either* from the EEInc *or* from the Tennessee Valley Authority (TVA) control area, whether 100 percent by just one of them or in some combination split between the two. Accordingly, focusing on the EEInc control area alone would not adequately capture all of the wholesale bulk power supply alternatives available to USEC's PGDP. This is an important consideration because the purpose of a competitive assessment is to determine whether a particular customer or grouping of customers might be subject to inappropriate price increases. The purpose is *not*, much more narrowly, to determine whether the concentration of generation control inside some pre-determined, albeit not economically meaningful, control area is somehow "too great." However, while I appropriately do not examine the effects of the proposed transaction on concentration in the EEInc control area taken by itself in the Pre-2006 or Post-2005 analyses, I do include a separate analysis that assesses the effects of the proposed transaction on market concentration for a combined EEInc-TVA control area destination market. I refer to this as the USEC Load analysis. The use of the combined EEInc-TVA control area destination market to assess the effects of the proposed transaction on USEC's PGDP load is consistent with the ability of that load to move between the two control areas.

An Appendix A Competitive Analysis Screen measures market concentration using Economic Capacity and Available Economic Capacity. Economic Capacity is all generation capacity located within the destination market being examined, or that can be delivered there after accounting for transmission prices, losses and limits, at a delivered price that is no more than 1.05 times the "competitive price" in the market. Available Economic Capacity is equal to Economic Capacity less that required to meet firm retail and pre-existing wholesale load commitments. I determine a range of competitive prices for these computations principally from forward price information provided by Ameren but also through a review of publicly-available historical and forward price information.

In determining which generators could deliver Economic Capacity and Available Economic Capacity, transmission flows into each destination market were capped by transmission limits. For this purpose I use First Contingency Incremental Transfer Capability (FCITC) information (both single path and simultaneous) developed by Ameren. The development of this FCITC information is explained in Mr. Whiteley's testimony. I use the FCITC data instead of Available Transmission Capacity (ATC) data because of concern that the zero ATC values reported on OASIS for many paths might not realistically portray the amount of transmission capacity that might be available for commercial transactions in the future and therefore inappropriately would distort the analysis. However, I also conduct sensitivity analyses using ATC data taken from OASIS sites. I use the same *simultaneous* control area transmission limits for both the FCITC and ATC analyses to cap control area imports. As is appropriate for an Appendix A analysis, I compute pre-transaction and post-transaction shares and Herfindahl-Hirschman Indexes (HHIs)[9] using both the generation within each destination market as well as that which could be delivered to the destination market from the outside up to appropriate (simultaneous and non-simultaneous) transmission limits.

My computations for the Available Economic Capacity measure are performed in the same fashion except that each supplier's load and firm long-term wholesale obligations are deducted from its Economic Capacity in order to determine the Available Economic Capacity that it might have available to sell in the destination market.

I compute pre- and post-merger HHIs, and therefore changes in HHIs, for a number of different destination market, season and load level combinations. For each destination market, I examine three seasons (summer, winter and spring/fall

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9 The HHI for a market is equal to the sum of the squared market shares (expressed as percents) of the individual firms in the market. Thus, a market with four equally-sized competitors has an HHI of 2,500 (i.e., $25^2 = 625$; 625 x 4 = 2,500) and a market with 10 equally-sized competitors has an HHI of 1,000 (i.e., $10^2 = 100$; 100 x 10 = 1,000).

combined) and five different load levels within each season. The different load levels and seasons collectively encompass a range of demand and price levels, reflect different generator capabilities and availabilities and incorporate different base case uses of the transmission system. As indicated, I do the analyses both for Economic Capacity and Available Economic Capacity.

My analyses employ a variety of conservative assumptions. By conservative, I mean that I have selected a technique or assumption that, in comparison to available alternatives, produces higher HHIs and higher HHI changes. If the transaction safely falls short of threshold levels for concern about transaction-induced competitive problems when these conservative assumptions are employed, one can be assured that it also will fall short of those threshold levels in cases where less conservative assumptions are employed.

Q. ARE THERE *A PRIORI* EXPECTATIONS ABOUT WHAT AN APPENDIX A ANALYSIS OF THE PROPOSED TRANSACTION SHOULD SHOW?

A. Yes. Under one set of criteria for assigning generation to market participants, Ameren's acquisition of all of Illinova's interest in Illinois Power and Dynegy's 20 percent interest in EEInc will result in no change in market concentration. Under the Commission's merger regulations, generation capacity associated with purchase and sale transactions – such as Ameren's, Illinois Power's and LGEE's purchases from EEInc – is attributed to the party that has the authority "to decide when generating resources are available for operation." 18 CFR Ch. 1, §33.3(c)(4)(i)(A). Since Ameren already owns 60 percent of EEInc, it plausibly already meets this operational control criteria for EEInc's generation even on a pre-transaction basis. If that is the case, then the proposed transaction does not result in any more of EEInc's generation moving to the Ameren bucket. On either a pre-transaction or post-transaction basis, 100 percent of EEInc's generation capacity would be assigned to Ameren. Under this interpretation, the only generation capacity that Ameren would acquire under the proposed transaction is the 5.25 MW associated with the jointly-owned State Farm diesels. This amount is obviously too small to suggest any competitive concerns in wholesale electricity markets and, in any case, are used only to meet load on Illinois Power's system.

But even if a presumption of operational control is *not* used to assign all of EEInc's generation to Ameren on a pre-transaction basis, and that capacity is assigned to market participants based on relative output rights instead, it still is inevitable that the concentration effects of the transaction will be slight in most control area destination markets. Dynegy owns 3,817 MW[10] of generation that is located in the Illinois Power control area and has output rights to 203 MW more (its Joppa steam station rights) that physically is located in the EEInc control area but which is delivered to the Illinois Power control area under existing firm transmission arrangements. It is the latter 203 MW, along with Dynegy's 15 MW 6B project interest, which is the subject of the proposed transaction. Dynegy also owns 1,650 MW located in the American Electric Power Company (AEP East) control area,[11] 180 MW in the ComEd control area and 495 MW in the LGEE control area.[12] Within the Illinois Power control area and directly interconnected control areas (each of which is also directly or contractually interconnected with Ameren), there are roughly 140,000 MW of generation, of which 14,474 MW is owned by Ameren and 6,355 MW is owned by Dynegy. The principal effect of the transaction on concentration of output rights for generation capacity will be to move 218 MW from the Dynegy bucket to the Ameren bucket, and that only in the Post-2005 time period. Dynegy therefore will become a little bit smaller and Ameren will become a little bit larger. But the amounts are inconsequential in comparison to the size of the market as a whole. Accordingly, my *a priori* expectation is that Ameren's acquisition of all of Illinova's interest in Illinois

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[10] This figure includes the 5.25 MW State Farm diesels.

[11] Of this amount, 825 MW, at Dynegy's Foothills and Riverside stations, is physically located in the AEP control area but telemetered to the Illinois Power control area.

[12] Each of the AEP East and LGEE control areas is directly or contractually interconnected with the Illinois Power control area. Dynegy also owns additional generating capacity that is more remote from Ameren and Illinois Power but which does not affect the analyses herein.

Power and Dynegy's 20 percent interest in EEInc will result in very little change in market concentration in most control area destination markets.

However, it is likely that screen violations will occur in the Ameren destination market in the Post-2005 scenario. Ameren is the largest owner of generation in the Ameren control area where it has traditional retail load supply obligations. That control area destination market, inevitably given Ameren's retail and wholesale load obligations, is "highly concentrated" under the joint US Department of Justice-Federal Trade Commission Horizontal Merger Guidelines (1992) (*Merger Guidelines*)[13] when the Economic Capacity measure is used. Even though the amount is very small, and represents little more than one year's retail load growth requirement on the Ameren system, moving the 218 MW of output rights from Dynegy's EEInc interest to the Ameren bucket clearly will result in screen violations in the Ameren market under the assumption used for the Post-Transition perspective that much of the EEInc generation already is located there.

The Appendix A screening analysis that I have conducted and report on herein reinforces the *a priori* perceptions discussed above.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR APPENDIX A ANALYSIS.

A. My Pre-2006 and Post-2005 analyses examine transaction-induced changes in concentration in six individual control area destination markets, Ameren, CILCO, ComEd, CWLP, Illinois Power and SIPCO. My USEC Load analysis examines transaction-induced concentration changes in a combined EEInc-TVA control area destination market. For each of these control area destination markets, I use both the Economic Capacity measure and the Available Economic Capacity measure to assess changes in market concentration during three seasons (summer, winter and spring/fall) and five load levels in each season. I find that, as expected, there are screen violations in the Ameren destination market for the Post-2005 analyses, but no other screen violations in any other scenarios or destination markets.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE PROPOSED TRANSACTION'S EFFECT ON POTENTIAL VERTICAL MARKET POWER CONCERNS.

A. I do not believe that the proposed transaction presents realistic concerns about vertical market power. Principal vertical market power concerns involving wholesale electricity supply generally are associated with fears that vertically integrated transmission owners will use their transmission assets to favor sales of their generation or their affiliates' generation over sales of generation by their competitors. However, the transmission facilities owned by both Ameren and Illinois Power are subject to Commission-approved Open Access Transmission Tariffs (OATTs). These tariffs should alleviate most concerns that those transmission systems would be used in anti-competitive fashion. Moreover, AmerenCILCO already is a member of the Midwest ISO and AmerenUE and AmerenCIPS have committed to join the Midwest ISO through a contractual arrangement with GridAmerica, an independent transmission company within the Midwest ISO. Also, as part of the present application, Applicants are seeking authorization for Illinois Power to join the Midwest ISO. These current and pending Midwest ISO memberships should alleviate any residual concern about preferential transmission access.

Both Ameren and Illinois Power own local gas distribution networks and, in principle, there could be a concern that, post-transaction, Ameren might use control of these gas distribution networks to deny natural gas transport to its generation competitors. However, each of these local gas distribution networks is

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[13] Under the *Merger Guidelines*, a "highly concentrated" market is one where the HHI is 1,800 or more while a "moderately concentrated" market is one where the HHI is between 1,000 and 1,800. An

available to other natural gas generators on a tariffed, open access basis and so any fear that competing generators might be harmed is moot. Moreover, while there are certain Dynegy-owned generators that receive natural gas transport service over Illinois Power's local natural gas distribution network, there are no independently-owned electric generators[14] that make wholesale electricity sales and that receive natural gas transport over either Ameren's or Illinois Power's local natural gas distribution networks. Additionally, there are seven interstate pipelines that traverse the service territories of Ameren's public utility operating companies (ANR Pipeline Company (ANR), Midwestern Gas Transmission Company (MGT), Mississippi River Transmission Corporation (MRT), Natural Gas Pipeline Company of America (NGPL), Panhandle Eastern Pipe Line Company (Panhandle), Texas Eastern Transmission Corporation, and Trunkline Gas Company (Trunkline)) and eight that traverse Illinois Power's service territory (Alliance Pipeline LP, ANR, MGT, MRT, NGPL, Northern Border Pipeline Company, Panhandle and Trunkline). Rather than receive local gas transport from either Ameren or Illinois Power, it is much more likely that any new gas-fired generator in the area would locate in proximity to one or more of these interstate pipelines and avoid entirely the need to procure local natural gas transport from Ameren post-transaction. Accordingly, concerns that Ameren, post-transaction, will be able to use its ownership of local gas distribution networks to thwart its generation competitors appear misplaced.

I also consider whether vertical market power issues might arise from the proposed transaction because post-transaction Ameren would control the supply of other inputs that its generation competitors might need. I determine that, while there are certain fuel transport and related facilities that Ameren owns, it is not reasonable to consider any of these as "entry barriers" that might thwart its

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"unconcentrated" market under the *Merger Guidelines* is one where the HHI is less than 1,000.

[14] In this context, independently-owned means owned by an entity other than Ameren or Dynegy. Dynegy's gas-fired generators located in the Illinois Power control area do receive local natural gas transport service from Illinois Power but, since Dynegy is one of the applicants here, it is reasonable to assume that it has considered and rejected the proposition that, post-transaction, Ameren will be able to exercise market power against it.

generation competitors and, as well, that there are no transaction-related consequences in any case. Moreover, to the extent that there is believed to be the potential for competitive problems as a result of the combined ownership of a natural gas distribution system and electric generators that receive natural gas transport service over that local distribution system, the transaction clearly is pro-competitive because it severs the ownership link between Dynegy, the largest generation owner in the Illinois Power control area, and Illinois Power's local gas transport service. For these reasons, I conclude that the proposed merger does not present any legitimate concerns about the creation or exercise of vertical market power.

III. OVERVIEW OF APPLICANTS' RELEVANT BUSINESS ACTIVITIES

Q. WHAT TOPIC IS DISCUSSED IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide a brief overview of Applicants' business activities that are most relevant for a competitive assessment of the proposed transaction.

Q. PLEASE DESCRIBE AMEREN.

A. Ameren is registered as a public utility holding company under the Public Utility Holding Company Act of 1935 and the parent of three public utility operating companies, AmerenUE, AmerenCIPS and AmerenCILCO. AmerenUE, the largest electric utility in the state of Missouri, sells electricity and natural gas to retail and wholesale customers, mostly in eastern Missouri, including the greater St. Louis metropolitan area, but also to some retail customers just east of St. Louis in western Illinois.[15] AmerenUE's forecast summer 2004 firm retail and wholesale electric load is 7,716 MW,[16] which it will meet through a combination of owned generation (7,961 MW for summer 2004) and firm purchases (including

[15] AmerenUE has requested regulatory authorization to transfer its Illinois retail service territory to AmerenCIPS.

[16] This figure, and that reported below for AmerenCIPS, assumes that the proposed transfer of AmerenUE's Illinois retail electric service territory to AmerenCIPS already has taken place.

from EEInc). AmerenCIPS sells electricity and natural gas to retail customers in central and southern Illinois. AmerenCIPS's forecast summer 2004 firm retail load is 2,565 MW. AmerenCILCO sells electricity and natural gas to retail customers in central Illinois, including in and around Peoria, and has a firm retail load of 1,142 MW as forecast for summer 2004. AmerenCILCO owns three small generating stations with a total capacity of 36 MW.

Pursuant to industry restructuring legislation in Illinois, the electric generating capacity formerly owned by AmerenCIPS was transferred to AmerenEnergy Generating Company (AEG) in May 2000. AEG has acquired additional generating capacity since that time such that its net installed generating capability now is 4,696 MW.[17] Most of that capacity currently is used to meet the demand of AmerenCIPS's firm retail customers and the firm wholesale customers of Ameren Energy Marketing Company (AEM). AmerenEnergy Resources Generating Company (AERG) is a wholly-owned subsidiary of AmerenCILCO and owns three generating stations with a total capacity of 1,129 MW. Ameren also owns AmerenEnergy Medina Valley Cogen, LLC (AmerenEnergy Medina Valley), which in turn owns the 38 MW Medina Valley cogeneration facility in Mossville, IL.[18]

Attachment 3 is a listing of the generating resources owned by Ameren through its AmerenUE, AmerenCILCO, AEG, AERG, AmerenEnergy Medina Valley and EEInc affiliates.

The transmission systems of AmerenUE and AmerenCIPS are operated as a single control area (referred to herein as the Ameren control area). AmerenCILCO's transmission system is operated as a separate control area

[17] AEG has proposed to transfer its Pinckneyville (320 MW) and Kinmundy (232 MW) stations to AmerenUE. The figures in the text for AmerenUE and AEG do *not* reflect that transfer.

[18] The Medina Valley cogeneration facility is used to serve the load of one of AmerenCILCO's retail customers and therefore is modeled as a load reduction, not a generation resource, in the Appendix A analyses described below.

(referred to herein as the CILCO control area). The Ameren control area interconnects physically or contractually with the following control areas: Alliant West (ALTW), AEP East, Associated Electric Cooperative, Inc. (AECI), Central and Southwest Corporation (CSW),[19] CILCO, Cinergy Corporation (Cinergy), the Columbia, MO municipal system (CWLD), CWLP, ComEd, EEInc, Entergy Corporation (Entergy), Grand River Dam Authority (GRDA), Illinois Power, Kansas City Power & Light Company (KCPL), LGEE, MidAmerican Energy Company (MEC), Missouri Public Service Company (MoPub), Missouri Western Resources (MOWR),[20] Northern Indiana Public Service Company (NIPS), Northern States Power Company (NSP), SIPCO, the Southwestern Power Administration (SPA), TVA, Western Farmers Electric Cooperative (Western Farmers) and Western Resources, Inc. (WR). The CILCO control area is directly interconnected with the following control areas: Ameren, ComEd, CWLP and Illinois Power.

There are several smaller electric systems that are located in or near the Ameren control area and that receive full requirements or some other form of wholesale electric service from either AmerenUE or AEM. These smaller systems collectively purchase more than 1,000 MW from Ameren. AmerenCILCO has only a single firm wholesale customer that purchases under a contract that expires March 31, 2004.

There is no retail electric customer choice in Missouri, but retail electric customer choice has been implemented in Illinois pursuant to the Illinois Electric Service Customer Choice and Rate Relief Law of 1997 (Illinois Electric Choice Law). Under this legislation, large business customers were able to choose alternate suppliers beginning October 1, 1999, remaining business customers were able to choose alternate suppliers beginning December 31, 2000 and residential customers were able to choose alternate suppliers beginning May 1, 2002. As

[19] AEP and CSW have merged. CSW sometimes is referred to as AEP West.

[20] MOWR is a control area operated by Western Resources for a group of municipal systems, some of which are served by Ameren's transmission lines.

well, under the legislation, the Illinois retail rates of AmerenUE, AmerenCIPS and AmerenCILCO were frozen through the end of 2004. That rate freeze since has been extended through the end of 2006. After that time, Ameren intends to procure all bulk power supplies used to meet the needs of its non-shopping Illinois retail customers via a competitive bidding process and the link between traditional rate-based generation capacity and retail pricing will be severed.

Ameren also owns (i) AEM, a power marketer that does not own any generation resources and which has entered into tolling arrangements for generating stations owned by AEG, and (ii) AmerenEnergy Fuels and Services Company, an entity that provides fuel procurement services for other Ameren affiliates and certain smaller electric suppliers.

Q. PLEASE DESCRIBE EEInc.

A. EEInc is jointly owned by Ameren (60 percent), Dynegy, through IGC (20 percent), and LGEE (20 percent). EEInc owns and operates the 1,014 MW Joppa steam station in Joppa, IL and, through its MEP subsidiary, owns and operates two 37 MW combustion turbine generators (CTs), referred to as the 6B project, and operates three other CTs (54 MW summer capability for each), referred to as the 7B project, that are owned by AEG.

Q. WHAT PARTIES HAVE THE RIGHTS TO RECEIVE THE OUTPUT FROM THE GENERATION THAT IS OWNED OR OPERATED BY EEInc?

A. Ameren (60 percent), Illinois Power (20 percent) and LGEE (20 percent) each have the right to take output from the Joppa steam station and, under grandfathered transmission arrangements, have that output delivered to the Ameren, Illinois Power and LGEE control areas, respectively. The existing contract governing the output of the Joppa steam station expires at the end of 2005. As well, Ameren (60 percent), Dynegy, through IGC (20 percent), and LGEE (20 percent) each have the right to take their proportional share of the output of the 6B project under a separate contract that expires at the end of 2004 but which is renewable at the option of the buyers. Ameren receives all of the output from the 7B project.

Q. PLEASE DISCUSS THE EXTENT TO WHICH AMEREN, AS MAJORITY OWNER OF EEInc, CAN EXERCISE OPERATIONAL CONTROL OVER THE JOPPA STEAM STATION AND THE 6B PROJECT.

A. There are multiple dimensions to the response to this question. EEInc is the operator of the Joppa steam station and the 6B project but Ameren is the majority owner of EEInc. That majority ownership conveys to Ameren certain rights and powers. Because of the rights and powers that are conveyed to Ameren by virtue of its majority ownership, it may be appropriate, for purposes of an Appendix A analysis, to assume that EEInc's direct operational control over the Joppa steam station and the 6B project has devolved to Ameren. If this is the case, of course, it would mean that it would be unnecessary to conduct an Appendix A analysis for the proposed transaction because the proposed transaction would involve essentially no change in operational control of generation facilities.[21] Ameren would have the same operational control both pre- and post transaction. I am not aware that the Commission previously has addressed the need even to conduct Appendix A analyses when there is no more involved than the majority owner of a jointly-owned generating entity increasing its ownership share in that jointly-owned entity.

However, notwithstanding that EEInc or Ameren may have operational control over the Joppa steam station and the 6B project for purposes of an Appendix A analysis, there are important provisions in the power supply contracts governing the Joppa steam station and the 6B project that sharply limit any practical ability

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[21] It similarly also would be unnecessary to conduct an Appendix A analysis if it is assumed that EEInc's direct operational control does *not* devolve to Ameren but stays at the EEInc level. Under such an assumption, EEInc would have operational control over the Joppa steam station and the 6B project both pre- and post-transaction and so operational control would not be changed by the transaction.

that Ameren might have to use that presumed operational control to withhold supply from the market in the hopes of profitably raising market price. For the Joppa steam station, Section 2.08 of the September 2, 1987 Power Supply Agreement Between Electric Energy, Incorporated and the Sponsoring Companies (Sponsors' Agreement) provides that, if one of the sponsors does not take the energy to which it is entitled, the other sponsors or USEC's PGDP can take that energy. Section 3.01 states that the price for that energy will be a cost-based price. The variable costs at Joppa are relatively low, less than $14 per MWH today.[22] For the 6B project, Section 4.1 of the Amended and Restated Power Supply Agreement Between Midwest Electric Power, Inc. and the Purchasing Parties (6B PSA) provides that, if one of the parties with output rights does not take the energy to which it is entitled, the other parties with output rights can take that energy. Section 5.1 of the 6B PSA outlines the cost-based pricing mechanism for that energy. There also are provisions in the Sponsors' Agreement and the 6B PSA that would limit either EEInc's or Ameren's ability to use the maintenance scheduling process to withhold capacity inappropriately. Section 1.07 of the Sponsors' Agreement provides for the establishment of a Coordinating Committee, on which each sponsor participates, that, among other things, would establish operating and maintenance schedules and control and operating procedures. The 6B PSA provides even stronger comfort on this score. Section 7.1 provides for the establishment of an Operating Committee, on which each joint owner participates, whose functions include establishing operating and maintenance schedules and control and operating procedures and also provides that "[a]ll decisions of the Operating Committee shall be unanimous." It also provides for arbitration in the event that unanimity is not reached.

[22] Notwithstanding that, under current contractual arrangements, the other owners would be able to take any energy that was available to but declined by Ameren, even if it were able and motivated to seek to exercise market power by withholding capacity, Ameren, almost inevitably, would not do so by withholding Joppa. Such a withholding strategy, if feasible and plausible, much more likely would rely on high cost resources, not Joppa.

Q. DOES EEInc OPERATE A CONTROL AREA?

A. Yes. The only generators located in that control area are the Joppa steam station and the 6B and 7B projects. However, unlike most traditional control areas, there is no captive load in the EEInc control area. The only load that can be served by the EEInc control area is USEC's load at its Paducah Gaseous Diffusion Plant, but that load can elect to be served *either* by the EEInc control area *or* the TVA control area. At its discretion, USEC's PGDP load can be served 100 percent by the EEInc control area or 100 percent by the TVA control area, or split between the two. As discussed further below, the ability of the PDGP load to move between control areas in this fashion has important implications for defining the relevant geographic markets within which to assess the competitive effects of the proposed transaction on it.

Q. PLEASE DESCRIBE ILLINOIS POWER.

A. Illinois Power sells electricity and natural gas to retail customers in portions of northern, central and southern Illinois. Its forecast summer 2004 firm peak electric demand is 3,488 MW, which it will meet through purchases from Dynegy (including Dynegy's Joppa steam station interest), AmerGen's Clinton nuclear unit, the State Farm diesels and approximately 10 MW from Qualifying Facilities (QFs). Illinois Power does not have any firm wholesale power customers. Several municipal and cooperative systems that are located in the Illinois Power control area are transmission service customers of Illinois Power but receive all of their wholesale bulk power requirements from other suppliers. Illinois Power's transmission system is directly or contractually interconnected with the following control areas: AEP East, Ameren, CILCO, ComEd, CWLP, EEInc, LGEE, MEC, SIPCO and TVA.

Q. PLEASE DESCRIBE DYNEGY.

A. In addition to Illinois Power, Dynegy owns 12,820 MW of generation spread among the Mid-America Interconnected Network (MAIN) (4,215 MW), East Central Area Reliability Coordinating Agreement (2,897 MW), Northeast Power

Coordinating Council (1,700 MW), Southeastern Electric Reliability Council (1,967 MW), Electric Reliability Council of Texas (822 MW) and Western Electric Coordinating Council (1,219 MW) reliability council regions. Dynegy also is engaged in the gathering, processing, marketing and distribution of natural gas and natural gas liquids but does not own any interstate natural gas pipeline facilities.

Attachment 4 provides a listing of the generating resources owned by Dynegy.

Q. PLEASE BRIEFLY DESCRIBE ILLINOIS POWER'S PURCHASES, INCLUDING THOSE FROM DYNEGY.

A. Dynegy currently sells up to 2,800 MW of capacity and energy to Illinois Power under one agreement and sells 45 MW of capacity and energy to Illinois Power under a separate agreement under which Illinois Power has an option to purchase an additional 85 MW of capacity and market-priced energy. The 2,800 MW purchase extends on an "evergreen" basis on a year-by-year basis unless notice to terminate is given in timely fashion. The 45 MW firm/85 MW option agreement also extends on an evergreen basis, for three-month periods, unless notice to terminate is given 45 days in advance. Illinois Power also contractually receives IGC's portion of the Joppa steam station and, in accordance with the First Amendment to the Purchase Power Agreement and Mutual Release Between AmerGen Energy Company, LLC and Illinois Power Company, 69.5 percent of the output from AmerGen's 1,034 MW Clinton nuclear unit. Illinois Power's contract with AmerGen expires at the end of 2004. Its Joppa steam station agreement expires at the end of 2005. In addition to the power from these sources, Illinois Power also purchases approximately 10 MW from QFs. Under the proposed transaction, Dynegy's existing sales to Illinois Power will be terminated and replaced by the new PPA and Memorandum PPA, which extend until the end of 2006 and replace the existing purchases from Dynegy, as well as certain yet-to-be executed agreements that will result from an RFP process and that will replace the capacity and energy under the Joppa steam station and Clinton contracts.

Under the new PPA, Dynegy will sell to Illinois Power 2,800 MW of capacity during May-September and 2,300 MW of capacity during October-April, with Illinois Power having the right to reduce these amounts by up to 200 MW if it loses retail load to competing suppliers or because of terminated business operations. Dynegy, not Illinois Power, will have dispatch control over the generators used to provide this service, except as necessary for grid reliability.[23] Dynegy will also provide all of Illinois Power's energy and ancillary services requirements during this time period beyond those met by certain "Qualified Agreements." The Qualified Agreements include Dynegy's Joppa steam station interest, the State Farm diesels and 700 MW that Illinois Power will procure via a competitive solicitation process (consisting of a 400 MW 24 x 7 block and a 300 MW 5 x 16 block) for 2005 and 2006 and an additional 200 MW for 2006. The 700 MW amount for 2005 and 2006 will replace that which now is provided by AmerGen's Clinton nuclear unit while the 200 MW amount in 2006 will replace that which now is provided by the Joppa steam station. Under the Memorandum PPA, Dynegy will sell to Illinois Power 300 MW of "regulatory capacity" in 2005 and 150 MW of regulatory capacity in 2006, with Illinois Power having the right to call for energy up to these amounts based on the index price at the Cinergy hub. These amounts, including the 10 MW purchased from QFs, collectively are expected to provide 100 percent of Illinois Power's requirements for its retail load through the end of 2006.

[23] Illinois Power now has dispatch control over Dynegy's generators located in the Illinois Power control area. Dynegy will assume dispatch control over those generators immediately after the closing of the proposed transaction. If the transaction closes before January 1, 2005, it is my understanding that interim arrangements will be implemented through an Interim PPA Rider such that, while Illinois Power (which at that point will be owned by Ameren) will have physical control over the dispatch of those units, except as needed to ensure grid reliability, it will be Dynegy and not Illinois Power (or Ameren) that determines which units are dispatched, when they are dispatched and how intensively they are dispatched.

IV. RELEVANT PRODUCT AND GEOGRAPHIC MARKETS AND APPENDIX A COMPETITIVE ANALYSIS SCREEN

Q. WHAT TOPICS ARE DISCUSSED IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I discuss the relevant product markets that should be considered in assessing the competitive effects of the proposed transaction and the Appendix A Competitive Analysis Screen that is used to examine short-term or non-firm energy markets.

Q. WHAT RELEVANT PRODUCT MARKETS DO YOU EXAMINE IN YOUR TESTIMONY?

A. The Commission generally examines short-term or non-firm energy, short-term capacity, long-term capacity and ancillary services markets in its market power investigations. My analysis of the competitive implications of Ameren's proposed acquisition of all of Illinova's interest in Illinois Power and Dynegy's 20 percent interest in EEInc focuses principally on markets for short-term or non-firm energy. It is this product market that is the subject of the Appendix A Competitive Analysis Screen discussed in Section IV.F below. However, I also briefly consider the effects of the proposed transaction on markets for short-term capacity, long-term capacity, ancillary services, retail electricity and transmission.

A. Short-Term Capacity

Q. PLEASE PROVIDE YOUR ASSESSMENT OF THE EFFECTS OF THE PROPOSED TRANSACTION ON SHORT-TERM CAPACITY MARKETS.

A. Short-term capacity generally is defined as capacity that is sold for time periods up to one year. The proposed transaction will not have any adverse effects on competition in short-term capacity markets. In the near term, through the end of 2005, pursuant to existing contractual arrangements, Dynegy's Joppa steam station interest will be used to supply the Illinois Power retail load and so Ameren will not be acquiring any new generation capacity that it might be able to sell in wholesale electricity markets on a short-term basis during that time period. [24] Accordingly, the proposed transaction will not affect short-term wholesale capacity markets during the time period before 2006. Moreover, while Ameren owns a substantial amount of generation capacity, it also has substantial load obligations that absorb almost all of the generation capacity that it owns. As such, Ameren has much less uncommitted capacity than does Dynegy.

While the proposed transaction will not result in any change in uncommitted capacity before 2006, beginning then the transaction actually will reduce the concentration of uncommitted capacity that can be used to supply short-term capacity markets. This will be true even in 2007 and beyond when Ameren's Illinois retail load obligations will be served from marketplace supplies secured through a competitive bidding process, and not by Ameren's resources (unless Ameren is a winning supplier in the competitive bidding process), which will increase Ameren's uncommitted capacity then in comparison to what it is today. Attachment 5, which is confidential, compares the forecast regional[25] load and capacity positions of Ameren and Dynegy in each of 2006 and 2007. The 2006 comparison takes into account the Illinois retail obligations that will exist then but the 2007 comparison assumes that neither Ameren nor Dynegy will have any Illinois retail load obligations at that time.[26] Based on Attachment 5, Dynegy's uncommitted resources in both 2006 and 2007 far exceed those of Ameren.

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[24] Ameren also will acquire Illinois Power's interest in the 5.25 MW State Farm diesels and Dynegy's 15 MW interest in the 6B project. However, the State Farm diesels are used only to serve load on Illinois Power's system. For that reason, the State Farm diesels are treated as a load reduction in my analysis rather than a source of generation capacity. Moreover, while Ameren will acquire Dynegy's 20 percent interest in EEInc, Dynegy's 15 MW share of the 6B project has been contracted to it on a long-term basis and therefore, as long as Dynegy does not terminate its purchase pursuant to that contract, will not be available to support short-term wholesale sales by Ameren.

[25] The Attachment 5 comparisons include only the loads and resources of Ameren and Dynegy that are located in the Illinois Power and directly or contractually interconnected control areas, i.e., AEP East, Ameren, CILCO, ComEd, CWLP, EEInc, LGEE, MEC, SIPCO and TVA. This area includes all of Ameren's loads and resources but only a portion of Dynegy's.

[26] Ameren and or Dynegy may secure some of the Illinois retail load through the competitive solicitation process. As well, some of the generation of each may be required to support local must run requirements. However, it is not possible to determine any such amounts now and so they are not reflected in the Attachment 5 comparisons.

B. Long-Term Capacity

Q. PLEASE DISCUSS THE EFFECT OF THE PROPOSED TRANSACTION ON MARKETS FOR LONG-TERM CAPACITY.

A. The Commission has determined, as a general matter, that market power concerns should not be present in long-term capacity markets because of the ability of new firms to enter the market.[27] This general conclusion is reinforced by actual evidence of entry in numerous regions throughout the country, including the MAIN reliability council region where both Ameren and Illinois Power are located. Attachment 6, which is confidential, provides a summary compilation of information from Platts[28] concerning recent and near-term prospective entry by non-utility generators (NUGs). The exhibit totals new NUG supply entering commercial operation, or expected to, during the 2000-2004 time period for the control areas directly or contractually interconnected with Illinois Power. The listing is impressive, identifying more than 23,000 MW of NUG projects entering service during this period in these areas.

The Commission also considers whether control of key inputs to electricity generation might be used to block entry by competitors. In this case, as I describe below, Ameren, on a post-transaction basis, will not control any such key inputs that could be used to block its competitors. Accordingly, the transaction, if consummated, does not present concerns about market power in long-term capacity markets.

The potential key inputs or "entry barriers" usually considered in the Commission's market power discussions include control of sites at which new

[27] See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Docket No. RM95-8-000 and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket No. RM94-7-001, Order No. 888 Final Rule, 75 FERC ¶ 61,080, April 24, 1996.

[28] Platt's states that its information about NUG projects has been developed from publicly-available sources including EIA-411 filings.

generation capacity might be constructed, control of fuel supplies and control of fuel transport facilities. As concerns sites at which new generation capacity might be constructed, the listing of new generating projects in Attachment 6 indicates that site unavailability (as well as unavailability of other key inputs) apparently is not thwarting such new supplies. Moreover, while Ameren owns multiple existing generating sites, some of which have the potential for siting additional units, other traditional suppliers have their own existing sites that undoubtedly also could be expanded. Based on this information, it is evident that, on a post-transaction basis, Ameren will not control all of the sites at which new generation capacity might be constructed and that site unavailability in fact is not blocking new entrants. Accordingly, there should be no transaction-induced concerns on this score.

As concerns fuel supplies and fuel transport facilities, most new generation facilities today are natural gas-fired CTs or combined cycles so the principal focus for an entry barrier assessment should be on control of natural gas supplies and transport. Ameren does not own any natural gas reserves and is not acquiring any with the proposed transaction and so obviously does not have the ability to withhold gas supplies from new generators that might compete with it. Ameren and Illinois Power each owns a natural gas distribution network and Illinois Power also owns 763 miles of Hinshawed gas transportation pipelines with diameters ranging from 2” to 20”. These facilities could be used to transport gas to new independent generators that might wish to locate in the Ameren or Illinois Power service territories. However, these facilities are available for use on a tariffed, open access basis to transport gas to new gas-fired generating stations and so Ameren, on a post-transaction basis, will not have the effective ability to deny local gas transport service to independent generators that might compete with it. As well, as indicated, there are multiple interstate natural gas pipelines that traverse the Ameren and Illinois Power service territories. A new natural gas-fired generator locating in the Ameren or Illinois Power service territories presumably could locate in proximity to one or more of those interstate pipelines and avoid entirely the need to use Ameren- or Illinois Power-supplied local natural gas transport service.

Ameren also owns certain other fuel supply and transport facilities, but none of those facilities suggests that Ameren might be able to thwart other generators that might compete with it either pre- or post-transaction. Ameren owns natural gas storage capability but this is made available to other customers at tariffed prices under state law. Moreover, Ameren's fuel storage capability is relatively small (28.85 Bcf) in comparison to that available from others (e.g., NICOR, which has 165 Bcf of storage capability[29] that is available to customers on an unbundled basis).[30] Illinois Power also owns and leases natural gas storage capability (16.46 Bcf) but this storage capability is used only to provide bundled service to its customers, and not as a separate unbundled service. Ameren owns both barges and rail cars that are used to bring coal to its generating stations and at times are leased to others, but rail cars and barges are available from many others as well. Ameren owns rail trackage inside the boundaries of its generating stations and a 45 mile operating railroad that runs from St. Louis to the area of its coal-fired Labadie generating station. The railroad is not currently being used for bringing coal to Labadie. Moreover, if another coal-fired generator were to locate in the vicinity of Ameren's St. Louis-to-Labadie rail line, it is my understanding that the rail line would be made available for hauling coal to that new plant on a common carrier basis. EEInc owns rail cars and a three mile railroad but these are used only to deliver coal to EEInc's Joppa steam station, and not for supplying others. If another coal-fired generator were to locate along the railroad, my understanding is that the railroad would be available for hauling coal to the new plant on a common carrier basis.

Ameren also owns a portion of a coal washing facility located at the site of the nearby mine that now is used to supply its Sioux and Meredosia stations. Among

29 http://www.nicor.com/en_us/residential/about_gas/underground_storage.htm

30 http://www.nicor.com/en_us/commercial/transportation_customer_services/unbundled_service.htm

other things, the coal washing facility removes sulfur and other impurities from the coal and, because the impurities have a lower heat content than the coal, increases the Btus per pound. The coal washing station also can be used to wash coal for others but Ameren's ownership of this facility hardly gives it any ability to exclude generation competitors. Generally, each coal mine has its own wash plant which is sized to wash the production from that mine and it would be unusual for a party to want to use a wash plant that was not at the mine site.

Ameren also owns the Meramec Terminal, a facility that transloads coal from rail to barge. Ameren uses this facility for its own coal requirements but also makes the capacity available to other parties who may be its competitors. However, ownership of this transloading facility does not give Ameren the ability to deny essential inputs to its generation competitors because there are other transfer terminals that they could use including three in the St. Louis area. Ameren also owns rail unloading facilities at eight other coal-fired generating stations, but these facilities are used only for coal burned at the stations where they are located and not for third parties. A generation competitor that wished to construct a new coal-fired generating station in the same general area presumably would wish to construct its own rail unloading facilities at the site of its new generator, and so Ameren's ownership of rail unloading facilities does not have any competitive significance.

In any case, under the proposed transaction, Ameren will not be acquiring any new barges, rail lines or cars (with the exception of those associated with its increased share of EEInc) or coal washing facilities, and so any effect that its ownership of such facilities might have on competitive conditions will not be changed by the proposed transaction.

For the reasons discussed above, there should be no concerns about transaction-induced control of key generation inputs that would create market power in long-term capacity markets.

C. Ancillary Services

Q. HAVE YOU ALSO CONSIDERED WHETHER AMEREN MIGHT BE ABLE TO EXERCISE MARKET POWER IN ANCILLARY SERVICE MARKETS AFTER THE PROPOSED TRANSACTION IS CONSUMMATED?

A. The Commission's Order No. 642 requires an analysis of "reserves and imbalance energy as separate products *when the necessary data are available*" (italics added). Among other items, the necessary data to perform such an analysis include the ramp rates of individual generators. As a general matter, such data are not publicly available and so I did not analyze these product markets quantitatively. However, while I did not perform a specific quantitative analysis of the effect of the proposed transaction on concentration in these markets, it seems highly unlikely that such an analysis would suggest any competitive problems if data were available to allow that analysis to be performed and if that analysis were performed properly. Excluding CILCO and EEInc, the Ameren control area is interconnected physically or contractually with 23 other control areas, three of which also are interconnected with the CILCO control area. Each of these 23 other control areas historically has provided or arranged for the provision of these services itself and not relied on Ameren for them. Accordingly, there are many potential suppliers of these services other than Ameren and so the proposed transaction, which in any case adds only 218 MW of generation capacity that can be used in wholesale markets to Ameren's portfolio, is not likely significantly to alter competitive conditions in ancillary services supply. Moreover, Dynegy will remain a potential supplier of ancillary services post-transaction, and so no potential supplier of ancillary services will be eliminated from the market as a result of the proposed transaction. As concerns the potential for the supply of ancillary services, all that will be occurring is that 218 MW of generating capacity that can be used for wholesale transactions will be transferred from the bucket of one potential supplier to the bucket of another.

D. Retail Electricity

Q. PLEASE DISCUSS THE EFFECTS OF THE PROPOSED TRANSACTION ON RETAIL COMPETITION.

A. The most important factor for ensuring competitive retail markets, in my view, is ensuring that retailing entities are able to procure the wholesale supplies that they need to resell to their customers in markets that are characterized by an absence of market power. The analyses that I present herein provide comfort on this score, that is, that the proposed transaction will not present concerns about unduly increasing market power in wholesale energy and capacity markets. Moreover, Illinois Power is classified as an Integrated Distribution Company (IDC) under the rules of the Illinois Commerce Commission, meaning, among other things, that it is not permitted to have an active retail marketing function. Two Dynegy affiliates currently are authorized to, and do, make competitive retail sales in Illinois as Alternate Retail Electric Suppliers (ARES). However, Ameren is not acquiring either of those affiliates. As well, even if those affiliates were to cease making retail sales in Illinois, for whatever reason, there would still be an ample number of actual and potential retail electric competitors in Illinois to ensure robust competition for retail electric load. Accordingly, I do not believe that it is necessary to address this topic further.

E. Transmission

Q. IS IT NECESSARY TO CONSIDER WHETHER THE AMEREN AND ILLINOIS POWER TRANSMISSION SYSTEMS REPRESENT COMPETING ALTERNATIVES BETWEEN PARTICULAR RECEIPT AND DELIVERY POINTS THAT WOULD BE SACRIFICED UNDER THE PROPOSED TRANSACTION?

A. No. The Commission’s push toward RTOs presumes that a cooperative relationship among transmission owners is more important than the competitive relationships that in some cases will be sacrificed when the RTOs are formed. Moreover, when Ameren, through GridAmerica, and Illinois Power each have joined the Midwest ISO, it will be the Midwest ISO that is the tariffed provider of transmission service, not Ameren or Illinois Power.

F. Appendix A Competitive Analysis Screen

Q. PLEASE DESCRIBE GENERALLY THE COMMISSION'S APPENDIX A COMPETITIVE ANALYSIS SCREEN THAT IS USED FOR ANALYZING SHORT-TERM AND NON-FIRM ENERGY MARKETS.

A. The basic approach under an Appendix A Competitive Analysis Screen is to define individual destination markets, determine the competitive price in each of those individual destination markets and then measure concentration and changes in concentration of ownership of generating resources that are in or can be delivered to that destination market at a delivered price that is no more than 1.05 times the competitive price in that destination market. The HHIs produced from this analysis then are compared to the threshold levels of the *Merger Guidelines*. If those threshold levels are not exceeded, then it generally will be concluded that the proposed transaction presents no concerns about horizontal market power. If the screening thresholds are exceeded, further analyses may be required before it can be determined whether the proposed transaction would have adverse competitive effects.

Two different generation capacity measures are examined in an Appendix A Competitive Analysis Screen. The first of these, Economic Capacity, is all capacity that can be delivered to the destination market at a price that is no greater than 1.05 times the competitive price in that market. The second, Available Economic Capacity, is equal to Economic Capacity less that required to meet the supplier's obligation to its native load customers plus its pre-existing firm wholesale commitments.

In determining which supplies can be economically delivered to each destination market, the analysis must incorporate transmission prices and losses and reflect transmission system limits. The analyses are to be conducted for different seasons and load levels, in order to reflect a variety of demand and supply conditions. In principle, the individual destination markets should include each entity that is interconnected with any of the transaction partners, plus any additional entities to which at least one of them has made significant sales in the past.

Determining which resources actually can compete in each destination market for each season and load level combination, at a price that is no more than 1.05 times the competitive price, requires taking into account variable costs (fuel, O&M and emissions) on a generator-by-generator basis, transmission limits (both non-simultaneous and simultaneous) and transmission prices and losses. Moreover, because it generally will be true that there are more generating resources that could use a particular transmission path or interface than that transmission path or interface can accommodate, it is necessary in the analysis to allocate the limited transmission capability among competing suppliers.

Q. WHAT ARE THE *MERGER GUIDELINES'* THRESHOLD LEVELS?

A. Under the Appendix A process, the HHI changes that are computed for Economic Capacity and Available Economic Capacity are to be compared to the threshold levels contained in the *Merger Guidelines*. The *Merger Guidelines* considers markets with post-merger HHIs less than 1,000 to be "unconcentrated." Mergers or acquisitions in unconcentrated markets ordinarily require no further analysis notwithstanding the level of HHI increase that results from the merger. The *Merger Guidelines* considers markets with post-merger HHIs between 1,000 and 1,800 to be "moderately concentrated." If a merger or acquisition in a moderately concentrated market causes the HHI to increase by more than 100, the transaction, according to the *Merger Guidelines*, "potentially raise[s] significant competitive concerns" depending on other factors such as ability to collude and barriers to entry. The *Merger Guidelines* considers markets with post-merger HHIs greater than 1,800 to be "highly concentrated." If a merger or acquisition in such a market causes the HHI to increase by more than 50, it "potentially raise[s] significant competitive concerns'' according to the *Merger Guidelines*, again depending on other factors. Having merger-induced HHI increases that exceed the threshold levels of the *Merger Guidelines* does not mean that a proposed transaction must fail on competitive grounds. Rather, it means only that applicants must provide additional information and that additional analyses must be performed.

G. Destination Markets and Market Participants

Q. IS IT NECESSARY TO CONDUCT AN APPENDIX A ANALYSIS TO ADDRESS THE EFFECTS OF THE PROPOSED TRANSACTION ON SHORT-TERM AND NON-FIRM ENERGY MARKETS?

A. It is not apparent that it is necessary to perform such an analysis. As discussed, if Ameren's majority ownership is deemed to convey to it operational control of the EEInc generation, and if operational control is the basis on which to assign generation to market participants' buckets for purposes of an Appendix A analysis, then no such analysis would be required because there would be no change in market concentration as a result of the proposed transaction. However, I have conducted an Appendix A analysis on the basis that output rights, not a presumption of operational control based upon majority ownership, should be used to assign the EEInc generation to the owners of EEInc.

Q. WHAT DIFFERENT PERSPECTIVES DO YOU USE TO DEFINE DESTINATION MARKETS FOR YOUR APPENDIX A ANALYSIS?

A. My Appendix A analysis examines destination markets under three different perspectives, which I refer to as Pre-2006, Post-2005 and USEC Load. These different perspectives are required to account properly for changes in the disposition of the output from Dynegy's 20 percent interest in the Joppa steam station and the unusual nature of the EEInc control area.

Q. PLEASE DISCUSS THE PRE-2006 ANALYSIS AND THE DESTINATION MARKETS EXAMINED IN IT.

A. The Pre-2006 analysis is most relevant for the time period until December 31, 2005 when existing arrangements for the transmission of the output from the Joppa steam station are in effect. Under these arrangements, the output from these generators is transmitted to the Ameren, Illinois Power and LGEE control areas, in proportion to the respective ownership shares of Ameren, Dynegy and LGEE in EEInc, under "grandfathered" arrangements. Post-transaction, Ameren will continue to deliver the output from the Joppa steam station to Illinois Power until the existing agreement expires on December 31, 2005. Accordingly, for the Pre-2006 analysis, I assume that the output from the Joppa steam station is moved to the control areas of the parties with output rights, i.e., the Ameren, Illinois Power and LGEE control areas, in proportion to those output rights. For Economic Capacity, I assign Dynegy's share (of both the Joppa steam station and the 6B project) to Dynegy in the pre-transaction computations and to Ameren in the post-transaction computations. However, I do not transfer this capacity to the Ameren bucket for the Available Economic Capacity computations because it will not be available for wholesale sales by Ameren during the Pre-2006 period. Dynegy's Joppa steam capacity will be used to supply Illinois Power's retail load during this time period while its 6B capacity will continue to be sold by EEInc to it. Thus, for the Pre-2006 perspective, Ameren's Available Economic Capacity does not change when moving from the pre-transaction case to the post-transaction case. This means that there will be no transaction-induced changes in market concentration for the Pre-2006 perspective using the Available Economic Capacity measure.[31]

For the Pre-2006 analysis, I examine individual control area destination markets centered on Ameren, CILCO, ComEd, Illinois Power, CWLP and SIPCO. While this is a smaller grouping of destination markets than might be suggested by a strict application of the Commission's regulations, based on their location, size

[31] It is my understanding that Illinois Power intends to procure 700 MW in 2005 through a competitive procurement process but that this will occur whether or not the proposed transaction is consummated. This means that Dynegy's Available Economic Capacity position likewise does not change when moving from the pre-transaction case to the post-transaction case.

and number of external interconnections, as I explain below, this grouping of control areas includes those where the concentration effects of the proposed transaction are likely to be the greatest. If the transaction passes muster in this set of control areas, it also will pass muster in other, more remote control area destination markets where the concentration effects will be less. I included a broader set of control area destination markets in my Docket No. EC02-96-000 Appendix A analysis for Ameren's acquisition of CILCO. In addition to the six control area destination markets included in the current study, I also included, in the Docket No. EC02-96-000 study, a number of additional control areas that are interconnected with Ameren.[32] I found then that, for that acquisition, which was roughly five times as large as the one proposed now in terms of the amount of generating capacity that will be changing hands, the transaction-induced HHI changes in these other, more "remote" markets were generally zero (across the various markets, load levels and seasons), always very small, and never rose above 3 for the Economic Capacity computations and 10 for the Available Economic Capacity computations.[33] In short, the concentration-changing effects of that prior transaction, which involved a much greater change in the ownership of generating capacity than the transaction now proposed, but in the same general geographic region, were almost non-existent in the more remote control areas. This provides strong evidence that the same zero or very low concentration changes would ensue if I were to examine a broader set of control area destination markets now. For that reason, my analyses herein appropriately focus only on the set of control area destination markets where transaction-induced HHI changes are most likely to be significant.

Q. WHY WERE THESE SIX DESTINATION MARKETS SELECTED FOR THE PRE-2006 ANALYSIS?

[32] Several of these additional control areas also are interconnected with Illinois Power.

[33] The post-transaction HHI was only 455 in the situation where the transaction-induced HHI change was 10.

A. The Ameren and CILCO control areas were included because these are where most of Ameren's existing generation is located.[34] Moreover, because Ameren is the traditional integrated supplier in each of these two control areas, with the obligation to serve retail load there, its market share naturally will be relatively high (using the Economic Capacity measure) as will be the overall market concentration (as measured by the HHI). These conditions mean that even relatively small acquisitions of generation capacity can create screen violations. For this reason, the Ameren and CILCO control areas are included as destination markets in the analyses herein. The CWLP and SIPCO control areas are included for a similar reason. Each of these systems is relatively small and interconnected with both the Ameren and Illinois Power control areas but with relatively few other control areas.[35] Accordingly, while Ameren does not own any generation in either the CWLP or SIPCO control areas, because of their small size and limited interconnections, they nevertheless suggest themselves as potential areas for concern about screen violations. The ComEd control area also is interconnected with both the Ameren and Illinois Power control areas (and with the CILCO control area) but, because it is much larger than the CWLP and SIPCO control areas, and has more extensive interconnections, it seems unlikely that the proposed transaction will cause any noticeable concentration changes there. I have included it in the analysis because, as the largest control area in Illinois, it undoubtedly is one that Illinois regulators will be concerned with. Finally, the Illinois Power control area is included because that is where Dynegy owns a substantial quantity of generation and because Dynegy's EEInc interest that Ameren will acquire is delivered there in the Pre-2006 analysis.

Q. PLEASE DISCUSS THE POST-2005 ANALYSIS AND THE DESTINATION MARKETS USED FOR IT.

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34 The only exceptions are the 7B project and its portion of the Joppa steam station and the 6B project, which are located in the EEInc control area, and its Elgin units (452 MW total), which are located in the ComEd control area.

35 CWLP also is interconnected with CILCO.

A. The existing arrangements for the disposition of the output from the Joppa steam station expire at the end of 2005. This will be the first point in time when Ameren has any additional capacity that it might market in wholesale electricity markets as a result of the proposed transaction. Moreover, after December 31, 2005, there no longer will be any necessary link between Dynegy's Joppa steam station share and the Illinois Power control area to which it historically has been delivered. My assumption is that post-transaction, after 2005, Ameren will market its portion of Joppa steam station output wherever it can fetch the best price and other terms and conditions for that output. I also assume that Dynegy would do the same with its share of the output if it were retained rather than sold to Ameren, and that any other party that purchased it, if not Ameren, also would do the same. For the Post-2005 analysis, one possibility would be to "leave" Dynegy's current portion and Ameren's portion of the output of the Joppa steam station in the EEInc control area where it physically is located because the reason that is present to move it out of that control area during the Pre-2006 time period no longer would exist. Leaving this generation in the EEInc control area means that it would be treated as any other generation in the Post-2005 analysis and, consistent with the procedures for an Appendix A study, bear appropriate transmission costs and losses, and compete with other generation for limited interface capability, in order to participate in remote destination markets. However, based on my understanding of transmission system conditions, there are not likely to be significant limits on moving this output from the EEInc control area to the Ameren control area. Accordingly, in my Post-2005 analysis, for modeling purposes, I assume that the current Joppa steam station shares of both Ameren and Dynegy are located in the Ameren control area.[36] If anything, this is a conservative approach to the extent that there might be times when transmission conditions limit the full transfer of this output from the EEInc control area to the Ameren control area. I treat Ameren's and Dynegy's share of the 6B project in

[36] However, I assume that LGEE's share is moved to the LGEE control area just as I do for the Pre-2006 analysis.

similar fashion.[37] For Economic Capacity, I transfer Dynegy's share of the Joppa steam station and its share of the 6B project from the Dynegy bucket in the pre-transaction computations to the Ameren bucket in the post-transaction computations. I do the same for Dynegy's Joppa steam interest in the Available Economic Capacity computations. However, Dynegy's 15 MW share in the 6B project remains in its bucket in the post-transaction Available Economic Capacity computations because it will be Dynegy, not Ameren, that has the ability to market that output during the Post-2005 period. In addition to the expiration of the existing arrangements for the disposition of the output from the Joppa steam station, the Post-2005 analysis also reflects, for the Available Economic Capacity computations, the expiration of Dynegy's obligations to provide capacity and energy to Illinois Power under the PPA and the Memorandum PPA.[38] I examine the same six destination markets in the Post-2005 analysis that I examine in the Pre-2006 analysis.

Q. PLEASE DISCUSS THE USEC LOAD ANALYSIS AND THE GEOGRAPHIC MARKET USED FOR IT.

A. The reason to define a relevant geographic market for purposes of a market assessment is to help determine whether some particular grouping of customers might be subject to the exercise of market power. The Commission's approach under Appendix A analyses is to use individual control area destination markets as the base for such an examination. EEInc operates its own control area and, therefore, strict adherence to the Commission's usual approach might suggest that it would be appropriate to consider the effects of the proposed transaction on concentration of generation capacity available to serve the EEInc control area. However, such an approach would not be helpful for determining whether any customers located there actually might be adversely affected by the proposed transaction.

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[37] This is the same way that I treated Ameren's and Dynegy's shares of the 6B project in the Pre-2006 analysis. The 7B project is presumed to be moved to the Ameren control area in both the Pre-2006 and Post-2005 analyses.

[38] This obligation will not expire until the end of 2006.

The only customer that *can* be served from the EEInc control area is USEC's Paducah Gaseous Diffusion Plant.[39] But that customer is *not* captive to the EEInc control area as might be the case for most other customers in most other control areas. The PGDP load can be moved back and forth between the EEInc and the TVA control areas and served 100 percent by either, or by some combination of the two. The choice of how PGDP will be served is that of USEC, not EEInc. Accordingly, focusing on just the EEInc control area alone, and ignoring the options presented by USEC's ability to be served from the TVA control area, would very seriously understate the bulk power supply alternatives available for the USEC load. For this reason, the use of the EEInc control area, taken by itself, is inappropriate for assessing the effects of the proposed transaction on PGDP's load. The purpose of a competitive assessment of a proposed transaction is to determine whether there might be an inappropriate and adverse impact upon one or more customers as a result of the transaction. It is not, as strict adherence to the single control area approach might suggest, to compute market shares and/or concentration measures within some pre-determined but not economically meaningful set of control areas. For this reason, I appropriately have not included an analysis of the effect of the proposed transaction on concentration in a destination market centered on just the EEInc control area. However, to address the effects of the proposed transaction on the concentration of supplies available to serve the PGDP load, in a fashion that is *consistent* with Appendix A, I have examined the concentration effects of the transaction on a destination market that consists of the combination of the EEInc and TVA control areas. The generation that I include in that destination market is all capacity located in either of these two control areas plus that which could be imported from the outside up to the appropriate (non-simultaneous and simultaneous) transmission limits.

39 The Paducah Gaseous Diffusion Plant is owned by the U.S. Department of Energy but leased to and operated by USEC. It is the only operating uranium enrichment facility in this country producing uranium fuel for nuclear generators. See http://www.usec.com/v2001_02/HTML/Facilities_PaducahOverview.asp. The PGDP load is significant. The peak design power capacity is 3,040 MW. See http://www.usec.com/v2001_02/HTML/Facilities_PaducahFacts.asp.

Q. WHAT TRANSMISSION LIMITS ARE USED FOR THE USEC LOAD ANALYSIS?

A. The transmission limits that I use for the USEC Load analysis are only those into the TVA control area, not those into the EEInc control area also. Eliminating the transmission lines into the EEInc control area for purposes of the USEC Load analysis avoids the double count that would arise if I separately included, for example, both the path from Illinois Power into EEInc and the path from Illinois Power into TVA, since those two paths undoubtedly to some extent are limited by the same system elements.

Q. IS THERE SUFFICIENT TRANSMISSION CAPACITY TO ALLOW THE JOPPA STEAM STATION TO SERVE THE USEC LOAD UNDER THE ASSUMPTIONS OF THE USEC LOAD PERSPECTIVE?

A. Yes. The transmission lines that connect the Joppa steam station to the PGDP facility were sized to be able to deliver that output to that load, so there obviously is sufficient transmission capacity between the two to support this assumption.

Q. WHAT ENTITIES ARE INCLUDED AS POTENTIAL SUPPLIERS IN YOUR DESTINATION MARKETS?

A. Schematic diagrams showing the control area supply sources used for my analyses are included as Attachment 7. Page 1 of Attachment 7 pertains to the Pre-2006 and Post-2005 analyses while page 2 pertains to the USEC Load analysis. I included as potential suppliers any market participants owning generation in any of the control areas shown in the diagrams.[40] In general, the control areas identified in the diagrams are the six destination markets used for the Pre-2006 and Post-2005 analyses, TVA and any control areas directly

[40] Note that EEInc does not appear as a control area supplier in page 1 of Attachment 7, the schematic diagram for the Pre-2006 and Post-2005 analyses. In the Pre-2006 analyses, the EEInc generation is presumed to be moved to the control areas of the parties with output rights. In the Post-2005 analyses, the Ameren and Dynegy shares, as explained, are presumed to be located in the Ameren control area while the LGEE shares are presumed to be located in the LGEE control area.

interconnected with any of the these seven systems. I have also included two other control areas that are directly interconnected with LGEE, the only joint owner of EEInc that is not party to the proposed transaction. This is a very conservative grouping of potential suppliers.

Q. WHY DID YOU NOT INCLUDE ADDITIONAL POTENTIAL SUPPLIERS IN YOUR ANALYSIS?

A. There simply was no reason to do so. The effect of including additional potential suppliers in the analysis would have been to reduce market concentration levels and the measured HHI changes from the transaction for each of the markets studied. However, the changes would not be significant.

Q. DID YOU INCLUDE SEPARATE DESTINATION MARKETS CENTERED ON WHOLESALE CUSTOMERS LOCATED IN THE AMEREN, CILCO AND ILLINOIS POWER CONTROL AREAS?

A. No. The effect of the transaction on options available to these smaller systems already is captured by the analyses for the Ameren, CILCO and Illinois Power destination markets. Accordingly, it is not necessary to examine separate destination markets for these smaller systems. For the same reason, I did not include a separate destination market centered on CWLD, a roughly 200 MW (peak demand) municipal system that operates its own control area and which is interconnected with Ameren and AECI but no one else. The Ameren destination market reasonably can be used to assess the potential effects of the transaction on options available to CWLD as well. The Ameren destination market similarly can be used to assess the potential effects of the transaction on options available to the participants in MOWR that are directly connected to the Ameren system.

V. DATA SOURCES AND ANALYTICAL PROCEDURES

Q. WHAT "TEST YEAR" DO YOU USE FOR YOUR ANALYSIS?

A. I use 2004 to develop the dataset for examining the likely competitive effects of the transaction in the near term. In some respects, however, the use of such a near-term time period acts to overstate the effects of the transaction as measured in my study, e.g., for the Post-2005 analyses. Over time, as new merchant capacity commences commercial operation, as the reach of regional transmission tariffs is expanded, and as the Midwest ISO assumes operational control over more transmission systems, the impacts of the proposed transaction may be less than shown in my study.

Q. PLEASE DESCRIBE THE DATA SOURCES USED IN YOUR ANALYSIS.

A. Conducting an Appendix A analysis requires assembling data for, among other things, generation ownership, generator capacities and variable costs, load responsibility by supplier, transmission capacities both on path-by-path and simultaneous bases and transmission prices and losses.

My principal source for data concerning generator size, type, location, ownership and certain operating characteristics (e.g., O&M costs and heat rates) was Platts' Base Case. Platts states that the information in this database was assembled from a variety of publicly-available sources, including FERC Forms 1 and 423, EIA Forms 411, 759, 767, 860 and 861 and NERC GADS. I believe that this database is a widely-used source of industry information and is appropriate for purposes of my analysis. I used it to avoid the time and expense involved if I were to have assembled the raw material myself. I used the then-current version of this same database for my analysis of the Ameren-CILCO merger in Docket No. EC02-96-000. I adjusted the Platts' generation data for Ameren and Dynegy based upon information provided by each of these entities.

I used planned and forced outage factors from Platts to derate generator capacities to levels which could be used in the analysis. Forced outages were assumed to occur throughout the year while maintenance was assumed to occur during the spring/fall season only.

The variable O&M figures in the Platts database include estimates of SO_2 emissions costs for coal units and so it was not necessary separately to develop information for sulfur content of fuel, allowance prices, the identity of scrubbed units, or changes in O&M costs attributable to scrubbing. Because none of the generating units included in my analysis is located in the Northeast, it was not necessary to take into account costs for NOx emissions.

Q. HOW DID YOU DETERMINE WHAT FUEL PRICES TO USE IN YOUR ANALYSIS?

A. For prices for natural gas, I added together month-by-month NYMEX futures prices for Henry Hub and month-by-month NYMEX Basis Swap Futures to obtain delivered price estimates appropriate for the 2004 study year for each plant. The resulting monthly forecast prices for each plant then were averaged to produce prices for the different seasons used in the analysis. For coal, I used historical data developed by Platts from FERC filings and escalated these to the study year using Energy Information Administration forecast coal price changes. I used a similar approach for oil prices except that these were escalated to the study year using NYMEX fuel oil futures. For nuclear plants, I assumed a very low $1 per mmBtu price in order to make sure that these always were in the dispatch. I employed a similar approach for other fuel types that seemed to indicate very low variable costs, e.g., solar, hydro, wind, waste and refuse.

Q. HOW DOES YOUR STUDY INCORPORATE NEW GENERATION CAPACITY ADDITIONS?

A. The Platts database that I used identifies new generating units expected to enter commercial operation in the coming years. Of course, there is always some uncertainty as to whether planned new generating units will commence commercial operations on schedule but, because the 2004 study year used for my analysis has already begun, the likelihood of significantly misstating the generating capacity in service during it is small.

Q. HOW DID YOU DETERMINE THE MARKET PARTICIPANTS' LOADS FOR USE IN DETERMINING THEIR AVAILABLE ECONOMIC CAPACITY?

A. Ameren provided information on its and Illinois Power's loads. For most other suppliers with load obligations, I obtained historical loads from FERC Form 714 and escalated these to the 2004 study year using regional reliability council growth rates. For a few suppliers, FERC Form 714 data were not available or as precise as other public sources, and so in those cases the other sources were used. These are identified in my workpapers.

Q. WHO IS RESPONSIBLE FOR SERVING ILLINOIS POWER'S RETAIL LOAD IN YOUR AVAILABLE ECONOMIC CAPACITY COMPUTATIONS?

A. Dynegy is responsible for serving all but 700 MW of Illinois Power's retail load in my Available Economic Capacity Computations under the Pre-2006 perspective.[41] Because Ameren intends to procure supplies in the market to serve Illinois Power's retail load after 2006, I have not assigned that load to any party in the Post-2005 and USEC Load computations. I believe that this is appropriate for the post-transaction computations because of Ameren's intention to procure supplies in the market to serve Illinois Power's retail load. I also believe that it is appropriate for the pre-transaction computations given the December 31, 2006 expiration of the retail price freeze in Illinois and Dynegy's ability to terminate its existing supply arrangement for Illinois Power. Even in the pre-transaction state, these factors sever the link between Dynegy's generation ownership and the Illinois Power retail load.

Q. WHAT SEASONS AND LOAD LEVELS DID YOU INCLUDE IN YOUR ANALYSIS?

A. My analysis includes three seasons (summer, winter and spring/fall) and five different load levels within each of these. Accordingly, there are a total of 15

[41] The 5.25 MW State Farm diesels are modeled as a load reduction, not a source of generation.

different seasonal and load level "slices" included in my analysis. The five different load levels, for each season, represent, respectively, the average of loads during the 2 percent of hours with the highest demands, the average of loads during the 10 percent of hours with the next highest demands, the average of loads during the 20 percent of hours with the next highest demands, the average of loads during the 35 percent of hours with the next highest demands, and the average of loads in the remaining 33 percent of hours with the lowest demands.[42] I used FERC Form 714 information on hour-by-hour loads in conjunction with the peak demand information to determine demand for each season and load period in the study. When utility-specific load shapes were not available, I used a load shape from a nearby supplier that has its peak demand in the same season. Looking at different seasons and load levels in the fashion that I have allows the analysis to incorporate a full range of market clearing price levels. It also allows the analysis to reflect different seasonal transmission limits and different seasonal generator availabilities. I define the summer season as the months of June, July and August, the winter season as the months of December, January and February, and the spring/fall season as all other months.

Q. WHAT PURCHASE AND SALE TRANSACTIONS SHOULD BE REFLECTED IN AN APPENDIX A ANALYSIS?

A. My understanding of the Commission's regulations is that only long-term purchase and sale transactions should be reflected in the analysis and that it is only appropriate to move capacity from the seller's bucket to the buyer's bucket if the transaction conveys operational control of generating units.

Q. HOW IS THE OUTPUT FROM EEInc ASSIGNED IN YOUR ANALYSIS?

A. As discussed, Ameren owns 60 percent of EEInc, which owns the Joppa steam station and, through its MEP subsidiary, the 6B project. EEInc also operates the 7B project that Ameren owns. As discussed above, based on my understanding of the Commission's regulations, I believe that it is questionable whether the

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[42] I used Ameren's hourly loads to make this determination.

proposed transaction involves the type of transfer of operational control of generating assets that require a detailed Appendix A analysis. *If* it is determined that Ameren's 60 percent ownership of EEInc makes it appropriate to include all of the EEInc generation in the Ameren bucket on a pre-transaction basis, based on a presumption that majority ownership conveys operational control of the generation, *then* it is not be necessary to perform the Appendix A analysis at all because the only generation-related effect of the proposed transaction, under that assumption, would be to transfer just the 5.25 MW State Farm diesels from the Dynegy bucket to the Ameren bucket.[43] If the proposed transaction involves only the movement of the 5.25 MW State Farm diesels from one bucket to another, it seems clear that it could not possibly have any adverse competitive effects in wholesale electricity markets. The 5.25 MW is a very small amount and, in any case, the State Farm diesels are used only to serve load on Illinois Power's system.

However, notwithstanding the questionable need for conducting an Appendix A analysis, I nevertheless have done so. For my Appendix A study, I allocate the capacity of the Joppa steam station and 6B project among Ameren, Dynegy and LGEE based on relative ownership shares for the pre-transaction computations and then transfer Dynegy's 20 percent from its bucket to Ameren's bucket for the post-transaction computations for Economic Capacity under all three perspectives (Pre-2006, Post-2005 and USEC Load). I do the same thing for Dynegy's Joppa steam station capacity for the Available Economic Capacity computations under the Post-2005 and USEC Load perspectives. However, for the Available Economic Capacity computations for the Pre-2006 perspective, I do not transfer any of Dynegy's Joppa steam station interest to the Ameren bucket because, during the pre-2006 time period, it will be used to serve the Illinois Power retail load and therefore will not be available for wholesale sales by Ameren. Accordingly, its acquisition does not increase Ameren's Available Economic

[43] For this reason, in my Economic Capacity computations provided to the Commission in Docket No. EC01-96-000 in conjunction with Ameren's acquisition of what are now AmerenCILCO and AERG, I

Capacity under the Pre-2006 perspective. I do not move Dynegy's 6B interest to Ameren post-transaction under any of these three perspectives for the Available Economic Capacity computations because that capacity will be sold to Dynegy and therefore will not be available for wholesale sales by Ameren. The capacity of the 7B project is included in the Ameren bucket on both pre- and post-transaction bases.

Q. PLEASE BRIEFLY DESCRIBE AMEREN'S LONG-TERM FIRM WHOLESALE ELECTRICITY PURCHASES OTHER THAN THOSE FROM EEInc.

A. Ameren has dispatch rights to 176 MW of generation owned by one of its wholesale customers, Soyland Power Cooperative, Inc (Soyland), as part of its power supply arrangement with Soyland. Ameren also has an arrangement with two of its wholesale customers (the municipal systems in Kahoka and Marceline, MO) whereby those systems get a credit on their capacity charge payments and, in turn, give Ameren the right to call on the energy from internal combustion engines that they own. The capacity covered by these arrangements totals nine MW. Ameren pays nothing for the first 100 hours of use per MW from these machines, and an incremental cost-based payment for any usage beyond 100 hours per MW. Ameren also has purchased the exclusive rights to dispatch 14 MW of internal combustion capacity owned by the Jackson, MO municipal system. There is a maximum number of hours each year that the capacity can be dispatched, and a minimum run period each time that it is dispatched. The dispatch price is $155 per MWH. In addition, AmerenCILCO purchases 50 MW from customer-owned generation sources. These purchases allow AmerenCILCO to meet its reserve target and, as well, can be used to provide energy when prices rise to the $100 per MWH level. AmerenCILCO does not pay separately for energy from those customer-owned units but, in exchange for demand charge credits on the customers' bills, receives the right to take energy from the units for up to a stated (e.g., 200) number of hours each year. Because each of the

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attributed all of EEInc's capacity to Ameren.

Soyland, Kahoka, Marceline, Jackson and AmerenCILCO-customer owned generation transactions conveys dispatch rights for generating facilities to Ameren, those generating facilities are included in the Ameren bucket in my analysis. Ameren also purchases 160 MW of system capacity and energy from Entergy under a contract that expires in 2008. The Entergy transaction does not involve operational control over generation and therefore does not cause any capacity to be moved to the Ameren bucket.

Q. PLEASE BRIEFLY DESCRIBE AMEREN'S LONG-TERM FIRM WHOLESALE ELECTRICITY SALES.

A. Ameren makes full requirements and other wholesale electricity sales to a number of municipal and cooperative systems located in or adjacent to the Ameren control area. These systems collectively purchase more than 1,000 MW from Ameren. Ameren also makes long-term firm sales to CWLD, the Illinois Municipal Electric Agency, the Wabash Valley Power Authority and Wisconsin Electric Power Company (WEPCO) totaling roughly 450 MW. The WEPCO sale is a tolling arrangement involving one of Ameren's Elgin units located in the ComEd control area. For purposes of the Appendix A analysis, that capacity (156 MW) is transferred from the Ameren bucket to the WEPCO bucket. None of the other long-term firm sales convey dispatch rights to generation capacity and so they do not involve moving any generation from Ameren's bucket to the buyer's bucket.

Q. HOW ARE DYNEGY'S POST-TRANSACTION SALES TO ILLINOIS POWER REFLECTED IN YOUR ANALYSIS?

A. Neither the PPA nor the Memorandum PPA involves the transfer from Dynegy to Illinois Power of operational control over any generation capacity and so, appropriately under the Commission's procedures, the capacity used to support this transaction remains in the Dynegy bucket on a post-transaction basis. Dynegy, not Ameren, will make the call as to which generation sources—whether Dynegy-owned or purchases in the market—it will use to meet its obligations under these agreements. Ameren's only rights in this regard arise during emergency conditions on the Illinois Power transmission system when it will be able to request that Dynegy operate generation to eliminate the emergency conditions. However, Ameren will not have operational control over any of the generators used to meet Dynegy's obligations, whether during emergency or ordinary conditions, and therefore it would not be appropriate to transfer any of this capacity to its bucket.

Q. WILL AMEREN ASSUME OPERATIONAL CONTROL OVER ANY OF DYNEGY'S GENERATION IF THE TRANSACTION CLOSES BEFORE JANUARY 1, 2005?

A. Not in any meaningful sense. My understanding is that Illinois Power currently has operational control over the generating units of Dynegy that are used to supply it with electricity and that Dynegy will assume operational control over these units immediately after closing of the proposed transaction. It is my understanding that, if the proposed transaction closes before January 1, 2005, Dynegy and Illinois Power will enter into an Interim PPA Rider that will become effective upon closing and terminate December 31, 2004. The purpose of the Interim PPA Rider will be to provide a mechanism to transfer operational control over the units used to serve Illinois Power's retail load from Illinois Power (which at this point will be owned by Ameren) to Dynegy consistent with Illinois Power and Dynegy no longer being affiliates. The Interim PPA Rider means that Ameren will *not* assume operational control over any of Dynegy's generators even if the transaction closes before January 1, 2005.

Q. **DID YOU REFLECT DYNEGY'S OTHER LONG-TERM PURCHASES AND SALES IN YOUR ANALYSIS?**

A. Yes. I have already discussed the treatment of Dynegy's EEInc interest and its sales to Illinois Power. As well, for its facilities located in the control areas that are part of my study, Dynegy provided information on its long-term sales. These sales were deducted from Dynegy's bucket for the Available Economic Capacity computations. None of these sales involve the transfer of operational control of generating units from Dynegy to another party, so no such adjustments were made for the Economic Capacity computations. However, in some cases Dynegy owns generating units jointly with another party. If that other party is the operator of the facility, it is included in that other party's bucket for the Economic Capacity computations.

Q. DID YOU REFLECT PURCHASE AND SALES TRANSACTIONS OF ENTITIES OTHER THAN AMEREN AND DYNEGY IN YOUR ANALYSIS?

A. I do not believe that it is necessary or possible to do so in any cost-effective fashion. For most purchase and sales transactions, it is either very difficult or impossible to identify whether the requisite transfer of operational control is involved. In any case, what is most important for purposes of an Appendix A analysis is to get accurate information on purchases and sales of the transacting parties. I have been supplied with this information for Ameren's and Dynegy's transactions. While it obviously would be desirable to have perfect information for all market participants' transactions, errors or omissions with respect to other market participants' transactions will have a much less important effect on study results than will errors or omissions concerning the transacting parties' transactions. For example, if a purchase or sale transaction involving another market participant is inadvertently omitted, the affected generation still will be included in the Economic Capacity analyses but incorrectly attributed. The errors from attributing too little generation to one market participant and too much to another will be largely offsetting. Depending on the precise circumstances, Ameren's shares of Economic Capacity and the HHI changes attributable to the transaction are likely to be unaffected, or only marginally affected, from errors involving incomplete identification of third-party transactions.

Q. PLEASE DISCUSS THE TRANSMISSION CAPACITY DATA USED IN YOUR ANALYSIS.

A. The FCITC transmission values developed for me by Ameren include non-simultaneous path-by-path limits, simultaneous limits into a control area from a particular direction and total control area simultaneous limits that apply into a destination market from all directions. The total control area simultaneous limits apply in all of the destination markets that I examine. The directional limits apply only for flows into or through the Ameren, ComEd, Illinois Power, LGEE and TVA control areas.[44]

I used the FCITC data instead of the ATC data that the Commission generally favors for Appendix A analyses because many of the ATC values taken from OASIS sites were zero.[45] I was concerned that these zero values were not representative of the amount of transmission capacity that might be available in the future for commercial transactions between particular sources and sinks, especially given that they do not reflect Ameren's and Illinois Power's participation in the Midwest ISO,[46] and therefore that their use inappropriately would distort my analysis. Mr. Whiteley discusses the development of and underlying rationale for the FCITC data that I used. However, while I used the FCITC data in my base case analyses, I also have conducted sensitivity analyses that use ATC values taken from OASIS sites. I use the same simultaneous control

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[44] Directional limits were not used for the CILCO, CWLP and SIPCO control area destination markets. Each of these control areas has relatively few external interconnections. This makes the use of the directional limits largely redundant. There is an additional reason why the directional limits are redundant for the CWLP and SIPCO control areas. For these two control areas, the non-simultaneous FCITC values are relatively close to each other and to the total control area simultaneous limit. This indicates that the same limiting elements are involved for each external path into the control area. Using the total control area simultaneous limit adequately accounts for the effects of that limiting element and nothing would be added by including the separate directional limits as well.

[45] For example, the ATCs into Ameren from AEP East, ALTW, CILCO, ComEd, Cinergy, CWLP, MEC, NIPS and NSP all are zero for each of the months in the March 2004 to February 2005 time period. With the exception of the path from Ameren, the ATCs into Illinois Power during summer (June, July and August) 2004 all are zero. The same zero values exist for imports into ComEd during the summer of 2004 except for the paths from CILCO and Wisconsin. All of the summer ATCs into CILCO and SIPCO are zero. All of the ATCs into LGEE are zero for the next 12 months.

[46] ATC values generally are not available now for the Post-2005 period used in this study.

area transmission limits for both the FCITC and ATC analyses to cap control area imports.

All of the FCITC and ATC values that are used in my study are included in my workpapers.

Q. WHAT WAS THE SOURCE OF YOUR DATA ON TRANSMISSION PRICES AND LOSSES?

A. This information generally comes from the various transmission providers' transmission tariffs, including those of the Midwest ISO, Mid-Continent Area Power Pool and Southwest Power Pool. I used the ceiling rates for non-firm service. Even though there may be a few cases where transmission providers today post discounts for service on particular paths in the near term, I had no basis to assume that such discounts would prevail into the future. In cases where there were separate peak and off-peak rates, I incorporated these in my analysis. Where there were no separate peak and off-peak rates, I used a single "all hours" rate. Where they were separately stated on a per MWH basis, I added ancillary service charges for (i) Scheduling, System Control and Dispatch and (ii) Reactive Supply and Voltage Control from Generation Sources services. Where there were no such separate ancillary service charges stated, I assumed that they were included in the base non-firm "access" charge.

Q. HOW HAVE YOU ALLOCATED LIMITED TRANSMISSION PATH CAPABILITY IN SITUATIONS WHERE THE AMOUNT OF POTENTIALLY COMPETING SUPPLY EXCEEDS THE PATH CAPABILITY (ADJUSTED AS APPROPRIATE TO INCORPORATE THE SIMULTANEOUS LIMITS)?

A. I use a "proportional" method, which means that I sum supplies deemed to be competing to use a particular path and then attribute to each supplier the amount of the path represented by the proportion that its competing supplies are of the total of all competing supplies. Thus, if supplier X has 200 MW of capacity deemed by the analysis to be competing to use a particular 400 MW path, and four other competing suppliers each have 200 MW as well, then supplier X will receive an allocation of 80 MW or its *pro rata* 20 percent share.

I use the proportional method because it recognizes the presence of all competing suppliers in the analysis. The principal alternative to this proportional allocation method is an "economic" allocation method that assigns limited transmission capability to suppliers with the lowest delivered costs. While perhaps more realistic in terms of which suppliers ultimately will gain access to limited transmission capability, the economic allocation method overlooks entirely in the HHI determinations all suppliers other than those that gain an allocation of the limited transmission capability that can deliver energy into the destination market at a price lower than 1.05 times the competitive price and therefore ignores the competitive pressures from those suppliers. Seemingly, therefore, it will artificially overstate market HHIs. For Economic Capacity, the economic allocation method also tends to assign high market shares to entities with substantial quantities of nuclear generation, effectively for purposes of an Appendix A analysis assuming that nuclear capacity can be used simultaneously in multiple destination markets. This occurs because the nuclear capacity has such low variable costs that it still can be economic in remote destination markets even after shouldering multiple transmission charges. The nuclear capacity actually squeezes out capacity that is more likely to be competing on the margin. The economic allocation method also suffers from "knife edge" properties, which means that very small changes in market clearing price (or transmission prices) can significantly, and unrealistically in my view, affect market shares and HHIs. For these reasons, I have selected the proportional allocation method.

Q. DOES YOUR ANALYSIS DEDICATE A PORTION OF THE TRANSMISSION CAPABILITY BETWEEN AMEREN AND ILLINOIS POWER OR BETWEEN CILCO AND ILLINOIS POWER TO AMEREN IN THE POST-TRANSACTION ANALYSES?

A. No. Such a dedication might be appropriate if Ameren intended to consolidate the Illinois Power control area with the Ameren or CILCO control areas, purchase a firm transmission path to allow load in the Illinois Power control area to be served by Ameren generation resources or designate network resources in one control area (e.g., Ameren) for purposes of serving network load in another (e.g., Illinois Power). However, as I understand things, none of these three are now contemplated.

Q. HOW DID YOU DETERMINE THE COMPETITIVE OR MARKET CLEARING PRICES TO USE IN YOUR ANALYSIS?

A. I developed a range of competitive prices for this purpose principally by examining forward price estimates developed by Ameren using a multi-region production cost model. With the production cost model, Ameren develops forecast hour-by-hour energy prices based on the cost of the marginal unit plus a capacity scarcity adder. The results for the near-term then are "benchmarked" using current market quotes. I averaged the hour-by-hour prices from Ameren for the time periods/load levels included in my study. The competitive prices that I use in my study essentially are equal to the prices from Ameren's model but increased upward so that, when multiplied by 1.05, as is done under the Appendix A delivered price test, they are divisible evenly by five (e.g., $20, $25, $35 and $45). I made an exception for the peak demand period in the summer (summer 1), where I increased the price from $80 to $100 in order to portray somewhat more extreme conditions where market power concerns might be greater.

After the multiplication by 1.05, the following are the prices used for the Competitive Analysis Screen:

Summer

1. $100 per MWH
2. $60 per MWH
3. $50 per MWH
4. $35 per MWH
5. $20 per MWH

Winter

1. $50 per MWH
2. $45 per MWH
3. $35 per MWH
4. $25 per MWH
5. $20 per MWH

Spring/Fall

1. $55 per MWH
2. $45 per MWH
3. $35 per MWH
4. $25 per MWH
5. $20 per MWH

VI. SUMMARY OF SCREENING ANALYSIS RESULTS

Q. PLEASE DESCRIBE THE EXHIBITS THAT PORTRAY THE RESULTS OF YOUR APPENDIX A ANALYSES.

A. The Pre-2006 results are summarized in Attachments 8 through 11. Each of these is a multi-page exhibit that provides for each destination market, season and load level examined: (i) pre-transaction and post-transaction HHIs and the transaction-induced changes; (ii) Ameren's and Dynegy's pre- and post-transaction capacity in MW;[47] and (iii) Ameren's and Dynegy's pre- and post-transaction market shares. Attachment 8 provides the base case Economic Capacity results, Attachment 9 provides the base case Available Economic Capacity results, Attachment 10 provides the Economic Capacity sensitivity results using ATC data, and Attachment 11 provides the Available Economic Capacity sensitivity results using ATC data. For each season, computations are provided for five

[47] The capacity identified in these exhibits has been adjusted to reflect planned and forced outages and, if located outside of the destination market, to take into account transmission prices, losses, and the need to compete for limited transmission space with other suppliers.

different load levels. These are labeled 1, 2, 3, 4 and 5, with 1 indicating the highest price and load level in each season and 5 indicating the lowest.

The results of the Post-2005 analyses are shown in Attachments 12 through 15**,** each of which is formatted in the same fashion as Attachments 8 through 11. Attachment 12 shows the base case Economic Capacity results, Attachment 13 shows the base case Available Economic Capacity results, Attachment 14 shows the Economic Capacity sensitivity results using ATC data, and Attachment 15 shows the Available Economic Capacity sensitivity results using ATC data.

The results of the USEC Load analyses are shown in Attachments 16 (base case, Economic Capacity), 17 (base case, Available Economic Capacity), 18 (sensitivity case, Economic Capacity) and 19 (sensitivity case, Available Economic Capacity).

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR COMPUTATIONS IN ATTACHMENTS 8 THROUGH 19.

A. For the Pre-2006 scenario (Attachments 8 through 11), for Economic Capacity, the markets (not surprisingly) generally are highly concentrated using the terminology of the *Merger Guidelines*, but the transaction-induced HHI changes are well below threshold levels for concern about market power. This is true both when using the ATC and the FCITC transmission measures. For the Pre-2006 Available Economic Capacity computations, the HHI changes always are zero. This is because, as described earlier, the transaction does not change the Economic Capacity of either Ameren or Dynegy during the Pre-2006 time period.

For the Post-2005 scenario (Attachments 12 through 15), for Economic Capacity, the markets also generally are highly concentrated. For both the base case and the ATC sensitivity, Economic Capacity screen violations occur during all seasons and time periods for the Ameren control area. The differences between the base case results and the sensitivity case results are minor. In the other markets, the

HHI changes for Economic Capacity are very small. They are negative in the Illinois Power market. For Available Economic Capacity, there are relatively minor base case screen violations in the Ameren market during summer 5, winter 4 and 5 and spring/fall 5. There are Available Economic Capacity screen violations in the Ameren control area destination market during summer 4 and 5, winter 1 through 5 and spring/fall 3, 4 and 5. In the other markets, the HHI changes for Available Economic Capacity are either very small or negative.

For the USEC Load scenario (Attachments 16 through 19), the market is highly concentrated for the Economic Capacity computations but the HHI changes are very small, no more than 4 under either transmission measure. For the Available Economic Capacity computations, the HHI changes are somewhat greater, but still rather small. The post-transaction market for the base case for all seasons and load levels, and for the ATC sensitivity in all season/load level combinations except summer 4 and 5, winter 5 and spring/fall 5, when it is at the low end of the moderately concentrated range, is unconcentrated under the *Merger Guidelines*' standard. The transaction-induced HHI changes are below the *Merger Guidelines'* threshold of 100 for potential competitive concern in moderately concentrated markets.

VII. VERTICAL MARKET POWER ISSUES

Q. DOES THE TRANSACTION SUGGEST COMPETITIVE CONCERNS BECAUSE OF AMEREN'S AND ILLINOIS POWER'S OWNERSHIP OF ELECTRIC TRANSMISSION SYSTEMS?

A. No. In principle, vertical market power concerns might arise if an integrated generation and transmission owner were able to use its transmission ownership to favor sale of its generation over sales of generation by its competitors, perhaps by limiting access to its transmission facilities or by reducing the quantity of transmission service that is made available. The implementation of open access transmission tariffs and codes of conduct pursuant to Commission Orders No. 888 and No. 889 should go far toward assuaging any such concerns. Remaining concerns should be assuaged by AmerenCILCO's participation in the Midwest ISO, the pending Midwest ISO participation, through GridAmerica, of AmerenUE and AmerenCIPS, and the commitment with the accompanying application that Illinois Power, when owned by Ameren, also will participate in the Midwest ISO.

Q. ARE THERE OTHER VERTICAL MARKET POWER CONCERNS SUGGESTED BY THE TRANSACTION?

A. No. Such concerns potentially might be present if Ameren on a post-transaction basis owned important inputs to electricity production that were needed by its generation competitors but were unavailable from other sources. But that is not the case here. Ameren does not own any fuel supplies used for electricity generation other than those located at its generating stations and intended to be used in those stations. Both Ameren and Illinois Power own local gas distribution networks but, as indicated above, each of these local distribution networks is available for use by others on a tariffed basis. Moreover, there are no independently-owned generators selling electricity in wholesale markets that are supplied with natural gas transport over either Ameren's or Illinois Power's natural gas distribution systems.[48] As well, as indicated, there are numerous interstate natural gas pipelines that traverse the Ameren and Illinois Power service territories. Almost inevitably, a new natural gas-fired generator that located in or near the Ameren or Illinois Power service territories would seek a site that was in close proximity to one or more of these interstate pipelines in order to avoid entirely the unnecessary expense and limited flexibility of service over a local natural gas distribution system. Both Ameren and Illinois Power own gas storage but the amounts they own are small in comparison to those owned by others in the region. Moreover, the gas storage capacity owned by Ameren is available to other market participants on a tariffed basis. Ameren's and Illinois Power's

[48] As discussed above, Dynegy's gas-fired generators in the Illinois Power control area do receive local natural gas transport service from Illinois Power but, since Dynegy is one of the applicants here, it is reasonable to assume that it has considered and rejected the proposition that, post-transaction, Ameren will be able to exercise market power against it by virtue of its ownership of the Illinois Power gas distribution system.

ownership of local natural gas distribution systems therefore is of no competitive significance in wholesale electricity markets.

The only other fuel transport facilities owned by Ameren are barges and rail cars. Ameren also owns the Meramec Terminal for transloading coal from rail to barge. However, the services provided by these facilities are available from numerous other sources so there is no competitive significance for wholesale electricity markets associated with Ameren's ownership. There likewise is no competitive significance associated with the coal washing and rail unloading facilities that Ameren owns. In any case, I am unaware that the Commission ever has indicated that competitive problems are likely to arise in wholesale electricity markets because generation suppliers own barges, rail cars, or coal transloading, washing and unloading facilities.

Q. HAVE YOU PERFORMED THE VERTICAL COMPETITIVE ANALYSIS THAT IS CONTEMPLATED IN THE COMMISSION'S RULES?

A. No. The Commission's rules provide that the vertical analysis need not be performed if there is only a *de minimus* overlap between Applicants' provision of inputs for electricity production and electricity output in the same geographic market and if the extent of the upstream product is used to produce only a *de minimus* amount of the relevant downstream products. Because Applicants provide so few inputs for electricity production by others, these conditions hold and the vertical analysis is not required here. Moreover, in the Illinois Power control area where Illinois Power transports natural gas for use in certain of Dynegy's generators, the proposed transaction actually would reduce market concentration under the procedures that the Commission uses for vertical market analyses. Under those procedures, in computing concentration in "downstream" markets, gas-fired generation is assigned to the pipeline or distribution system that supplies it. This means that post-transaction Dynegy's gas-fired generating units in the Illinois Power control area would be assigned to Ameren, the new owner of the Illinois Power natural gas distribution system. The effect of the transaction therefore will be to reduce the number of MW attributed to Dynegy, the largest supplier in the Illinois Power destination market. Because Ameren is only a small participant in the Illinois Power destination market on a pre-transaction basis, and neither owns nor provides inputs to generation facilities located there, this necessarily will reduce market concentration in the Illinois Power control area as measured by the HHI.

VIII. MITIGATION

Q. DO THE SCREEN VIOLATIONS REPORTED FOR THE AMEREN CONTROL AREA DESTINATION MARKET IN THE POST-2005 ANALYSES IN ATTACHMENTS 12 THROUGH 15 INDICATE THAT IT IS NECESSARY TO IMPLEMENT MARKET POWER MITIGATION MEASURES AS A CONDITION FOR APPROVAL OF THE PROPOSED TRANSACTION?

A. In my view, it is highly questionable as to whether any such market power mitigation measures should be required. There are several reasons. One is that the 218 MW amount of generating capacity output rights that will change hands under the proposed transaction and that can be used for wholesale transactions is very small. It is about one percent of the supply available to serve the Ameren control area destination market during peak demand periods under the procedures of an Appendix A analysis and only about 1/10 of one percent of generation capacity in the area encompassed by the Ameren control area and the control areas that are directly interconnected with the Ameren control area. It also represents less than a year and a half of growth requirements on the Ameren system. A second reason is that it is not apparent that it is necessary to do an Appendix A analysis for the proposed transaction given that, as discussed, Ameren may already be presumed to have operational control of the EEInc generation under the Commission's procedures for conducting Appendix A analyses. If Ameren's current majority ownership of EEInc is deemed to convey to it operational control of EEInc's generators, then that generation capacity already would be included in the Ameren bucket on a pre-transaction basis in an Appendix A analysis and therefore nothing would change as a result of the proposed transaction. The screen violations in Attachments 12 through 15 occur only under the assumption that, pre-transaction, Ameren either does *not* have the operational control of the EEInc generators that its majority ownership of EEInc otherwise might suggest, or that, in apparent contrast to the Commission's requirements for Appendix A analyses, it is appropriate to assign EEInc's generation capacity to market participants based on output rights rather than operational control. A third reason concerns the timing of the screen violations, which occur only in the Post-2005 analysis but not in the Pre-2006 analysis. Important regional power supply changes that occur between now and 2006 are likely to reduce potential concerns about competitive problems in wholesale electricity markets. These include Ameren's participation (through GridAmerica) in the Midwest ISO, the implementation of the Midwest ISO's formal energy markets and the initiation of its active market monitoring function. As well, it is inevitable that Ameren will seek to market to other parties on a firm basis the additional generation capacity at EEInc that it will acquire under the proposed transaction. If Ameren is successful in marketing that capacity, that will diminish any incentive that it otherwise might have to seek to exercise any transaction-caused market power that it is deemed to have during the Post-2005 time period.

Q. PLEASE DESCRIBE THE MITIGATION MEASURES THAT AMEREN HAS PROPOSED ON THE ASSUMPTION THAT, NOTWITHSTANDING THE ABOVE DISCUSSION, THE COMMISSION BELIEVES THAT COMPETITIVE PROBLEMS ARE LIKELY TO ARISE AS A RESULT OF THE PROPOSED TRANSACTION IN THE POST-2005 TIME PERIOD AND THAT THERE SHOULD BE MITIGATION TO ADDRESS THEM.

A. Under those mitigation measures, which are described more fully in Mr. Nelson's testimony, on the assumption that each of EEInc's owners receives its proportionate share of the output from the Joppa steam station in the Post-2005 time period, Ameren would sell by contract a sufficient portion of the additional

Joppa steam station output that it will acquire under the proposed transaction to eliminate the screen violations that occur in the Ameren control area destination market in the Post-2005 analyses. That amount is 125 MW. The sales will be made (i) pursuant to a competitive solicitation conducted by an out-of-control area buyer, (ii) pursuant to a solicitation conducted by AEM or (iii) pursuant to some combination of these two. The sales will continue until Ameren or its subsidiaries installs sufficient new transmission system upgrades to increase import capability into the Ameren control area by 125 MW or until Ameren demonstrates to the satisfaction of the Commission that it should no longer be subject to such forced sales obligations. However, in no case will those sales obligations extend past April 30, 2009. The solicitations into which the Joppa capacity might be bid include those that will be conducted by Illinois Power to replace its existing bulk power sources. Illinois Power will be the only Ameren affiliate that is permitted to bid on the to-be-sold Joppa capacity.

Q. ARE THESE PROPOSED MITIGATION MEASURES SUFFICIENT TO ADDRESS PERCEIVED COMPETITIVE CONCERNS ARISING FROM THE PROPOSED TRANSACTION?

A. Yes.

Q. HOW WILL THE PROPOSED MITIGATION SALES AFFECT THE SCREEN VIOLATIONS THAT YOU REPORT FOR THE AMEREN CONTROL AREA?

A. Attachments 20 and 21 are Post-2005 mitigation analyses that assume that, in the post-transaction scenario, Ameren has sold to another party, on a contractual basis, 125 MW of the Joppa steam station interest that it will acquire from Dynegy. Attachment 20 provides the Economic Capacity analysis whereas Attachment 21 provides the Available Economic Capacity analysis. Other than the assumption that 125 MW of the to-be-acquired Joppa steam station interest is sold to another party in the post-transaction scenario, Attachments 20 and 21 are the same as my base case Post-2005 analyses provided in Attachments 12 and 13.

Each of the transaction-induced HHI changes in Attachments 20 and 21 falls below the Merger Guidelines screen levels.[49]

Q. ON OTHER OCCASIONS THE COMMISSION HAS EXPRESSED A PREFERENCE THAT CAPACITY SALES TO MITIGATE COMPETITIVE PROBLEMS ASSUMED TO BE ASSOCIATED WITH SCREEN VIOLATIONS CONVEY OPERATIONAL CONTROL OF GENERATING FACILITIES. IS THAT A CONCERN HERE?

A. No. As indicated, it is not apparent that Ameren's acquisition of Dynegy's EEInc interest will convey to it any *additional* operational control over generating facilities for purposes of an Appendix A analysis beyond what it already has. Accordingly, there should be no need for Ameren to shed itself of operational control of any generating facilities as a result of the transaction. The proposed mitigation is appropriate if the need for that mitigation is believed to arise from Ameren's acquisition of additional output rights, not its acquisition of additional operational control.

Q. ALTHOUGH THE MITIGATION PROPOSAL IS NOT A "SYSTEM SALE," DOES IT NEVERTHELESS HAVE IMPORTANT FEATURES THAT HELP ENSURE THAT AMEREN, IF IT HAS OPERATIONAL CONTROL OF THE JOPPA GENERATION, WILL NOT BE ABLE INAPPROPRIATELY TO WITHHOLD THE AMOUNT IT WILL SELL?

A. Yes. Ameren has the rights to the majority of the output from the 6 unit Joppa steam station. Accordingly, if it were to seek inappropriately to withhold output from the Joppa steam station, most of the withheld output would come from its share. Moreover, under Ameren's proposal, the *first* 125 MW of output from the 203 MW Joppa steam station share that Ameren will acquire under the proposed transaction would be subject to the mitigation sale. In other words, there would

49 The computations in Attachments 20 and 21 assume a mitigation sale of 125 MW based upon the full 1,014 MW output of the Joppa steam station, with proportional reductions in the sale amount if output falls below that level. In fact, as discussed below, the 125 MW sale has a higher priority than modeled. The results in Attachments 20 and 21 therefore are conservative.

have to be a curtailment of 78 MW of the 203 MW share being acquired by Ameren before there would be any reduction in the amount of power sold under the mitigation sale. Because curtailments in the output of Joppa are shared pro-rata among those with output rights, the amount of the output under the mitigation sale would not be affected by any curtailments at Joppa unless the total output at the 6 unit, 1,014 MW station fell below 61.6 percent or 624 MW.[50] Curtailments below that level would reduce the amount of the output for the mitigation sale, but Ameren, as the majority owner, still would bear a much greater burden. Because Joppa is a relatively low cost source of generation, there is little incentive to engage in such a withholding strategy, which undoubtedly would be very expensive to implement.

Q. WHAT IS THE PURPOSE OF THE APRIL 30, 2009 TERMINATION POINT FOR AMEREN'S SALES OBLIGATION UNDER THE MITIGATION THAT IT HAS PROPOSED?

A. This proposed termination point is more than five years after the announcement of the proposed transaction. That time period should be more than sufficient for any parties needing to purchase generating capacity to be able to enter into appropriate contractual arrangements with other suppliers, or construct their own new generating capacity, so that they are not subject to the presumed transaction-induced ability of Ameren to exercise market power against them. The set termination date therefore contributes to ensuring that the sales obligation will not be in place for any longer period than is necessary and therefore does not, artificially affect competitive wholesale electricity markets.

IX. CONCLUSION

Q. DO YOU HAVE AN OVERALL CONCLUSION?

A. Yes. Ameren's acquisition of Illinois Power and Dynegy's 20 percent interest in EEInc, which will give it only 218 MW more of generation capacity that can be

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[50] These figures are derived as follows: (125/203) is equal to .616 and .616 x 1,014 MW =624 MW.

used in wholesale electricity markets, will not have an adverse competitive effect. However, if the screen violations that are identified in the Ameren control area destination market in the Post-2005 analyses based upon output rights are believed to represent real competitive concerns, these competitive concerns are fully addressed by the mitigation measures discussed herein.

Q. DOES THAT CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.