HOW SHOULD GENERATING ASSET ACQUISITIONS BY REGULATED, VERTICALLY INTEGRATED UTILITIES BE OVERSEEN IN TODAY'S QUASI-REGULATED ELECTRIC UTILITY ENVIRONMENT?

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ABSTRACT

Problem

The utility environment is moving from its historical position as a regulated, monopolistic marketplace to a competitive, deregulated environment. Federal regulations over the past thirty years have recognized, and promoted, this move towards competition in the utility environment. In most areas of the country, however, the current market can best be described as quasi-competitive, resembling a competitive marketplace in some areas, while retaining monopolistic, regulated aspects in other areas.

This move toward competition encouraged construction of a large number of merchant generating facilities in the late 1990’s and early 2000’s. Several of these facilities have entered a state of financial distress, and are being forced into divestiture.

When the utility, operating in this quasi-competitive environment, is the purchaser of these facilities, several areas of concern related to the impacts on both the current and future competitiveness of the marketplace arise. The current methods of applying federal regulatory process to these purchases fail to effectively address these anti-competitive impacts. New practices must be implemented to deal with this new environment.

Method

Initially, a historical review of the significant federal legislation and regulations is presented. This examination provides a background for discussion of current regulatory practices, and provides a reference for creation of modifications to these practices.

The first significant legislation that dealt with utility regulation was the Federal Power Act of 1935. These regulations went largely unchanged until implementation of two key pieces of legislation in the 1970s, the Energy Policy Act and the Public Utilities Regulatory Policy Act. In 1992, the Energy Policy Act was modified by Congress, resulting in a cascade of FERC regulations designed to move the marketplace towards a more competitive environment. Examination of the application of these regulations to a recent case study showed the deficiencies of application of these regulations.

This historical reference was used to create a proposed set of modifications to the current regulatory practices.

These modifications include:

- Market concentration after the transaction should be brought back to levels near those that existed before the transaction. This is brought about by increases in potential competitive supply far in excess of what is demanded under current practices.

- A competitive bid process should be implemented to ensure that the increase in competitive supply has actual access to the market.
- A market monitor should be put in place to oversee the competitive bid process, as well as the utility's operation of the transmission system.
- In order to balance competition with ratepayer's interest, implementation of the competitive bid process and the market monitor should be done under the auspices of the state regulatory commission.
- An alternative to the above four steps is forced divestiture of existing utility generation that equals in capacity the purchased generation.

The effectiveness and appropriateness of these proposed modifications was examined in two ways: through application to a case study, and by gauging industry support through the use of a survey of qualified industry professionals.

Findings

The results of the study indicate that the majority of the proposed modified regulatory practices not only effectively address the deficiencies of the existing regulatory practices, but also enjoy broad industry support among the survey group.

Market concentration (horizontal market power) is addressed by requiring increased potential supply to reduce market share and market concentration to levels that would pass FERC, DOJ and FTC requirements. Competitive bid process for this increased potential supply ensures that the increased potential supply has appropriate access to the marketplace. Additionally, a competitive bid process decreases the utility's incentive to operate its transmission system in a way which would disadvantage potential competitors. Implementation of a market monitor decreases the utility's ability to operate its transmission system in a way which would disadvantage competitors. The long term impacts of the transaction are dealt with by ensuring that there are no additional barriers to entry put in place by increases in market concentration, or the ability and incentive of the utility to foreclose competitors from the market.

All of the four above recommendations enjoyed levels of support ranging from 56% to 88% of the study population. The proposal to force divestiture of utility generating assets, however, was opposed by a large majority of the study group. While divestiture of an equal amount of generation by the utility addresses all three areas of concern by creating a marketplace environment that is as close as possible to that which existed before the transaction, the vast lack of support for this proposal raises questions about its appropriateness.

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CHAPTER 1 INTRODUCTION

During the 1990s and early 2000s, the regulatory environment in the electric energy market changed dramatically. Beginning with the Energy Policy Act (EPAct) of 1992, and continuing with a series of Orders by the Federal Energy Regulatory Commission (FERC Orders 888, 889, 2000, and 2003), the federal government moved aggressively to modify the utility environment from one of a regulated, monopoly basis to a market-driven, competitive basis.

This has created an electric power market that, in most regions of the country, is not quite competitive, but has moved away from the historic regulated monopoly environment. Often utilities, through their subsidiary and affiliate companies, operate in both a competitive, market-based environment and a regulated, cost-based market. A key responsibility of the regulatory bodies overseeing utilities and their actions is to ensure that actions taken in one market do not have an anti-competitive effect on the other.

The late 1990s and early 2000s also saw unprecedented growth in the size, number and technological advancement of merchant power generating facilities although construction of transmission facilities have not kept up (Hirst & Kirby 2001). Figure 1 shows the size and number of merchant facilities beginning construction during the period from 1999 to

2001. These facilities, as a whole, are more efficient, have lower emissions, and respond more quickly than traditional utility generating plants. Notwithstanding the technical superiority of these plants, many have been forced into a distressed financial situation. Whether through a corporate decision, or through the bankruptcy process, many of these facilities are being divested by the corporate entity.

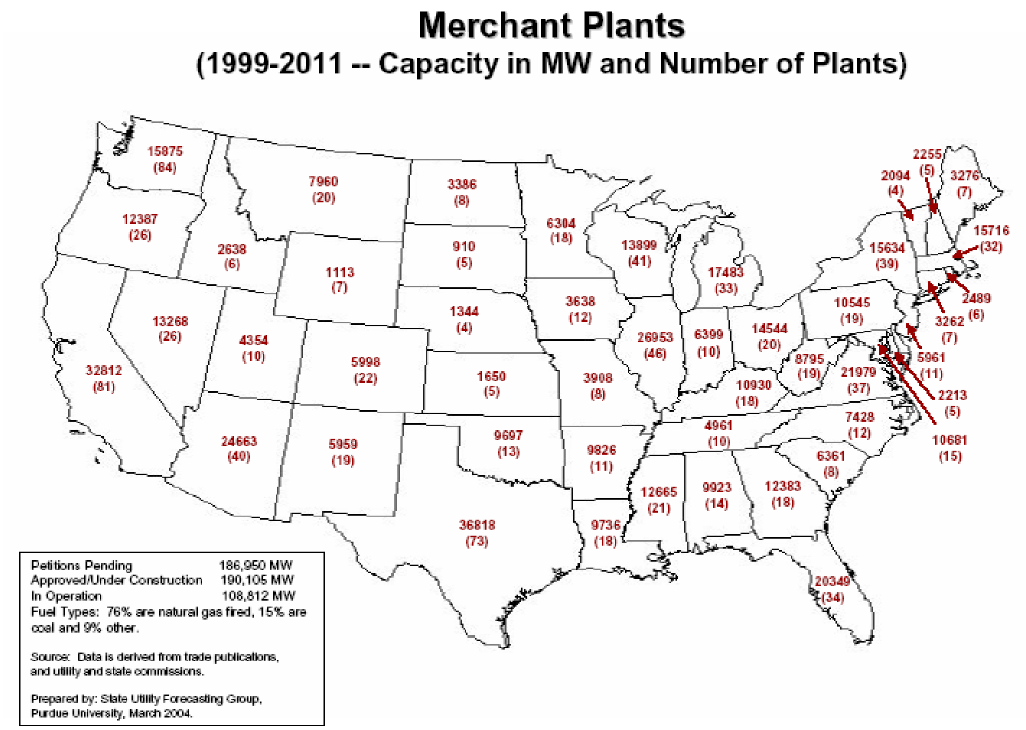

Figure 1 - Merchant Plant Construction in the US
Source: Purdue University State Utility Forecasting Group

As these facilities are divested, a natural potential purchaser is the vertically integrated utility in whose control area the plant is located. These utilities most often are able to purchase these facilities at a price much below costs for construction of a new facility. While this may be good for the stockholders of the utility, and has the potential to offer benefit to the utility's existing ratepayers, it raises several serious questions regarding the utility's and the generating facility's role in a future competitive market. Specifically, there are three areas of concern that must be examined to ensure that such an acquisition does not stifle competition in a future competitive marketplace or create irreparable harm to the current market environment:

1. Increased vertical market power.
2. Increased market concentration.
3. Dominance in a future deregulated market.

Analysis of the competitive effects of a transaction must recognize the impacts to both the current and future markets. Mitigation efforts that are intended to offset anti-competitive effects of a transaction need to offset increases of these effects in both the current and future marketplace. It is the responsibility of the federal regulatory agencies to protect competition and to ensure that such transactions do not harm the public interest by decreasing competition. Balancing these needs are requirements at the state level for the utility to serve its retail customers in a cost-effective, reliable manner.

Statement of the Problem

The current regulatory approval process is deficient in its oversight function for utility purchases of previously unregulated generating facilities. Currently used methods, analyses, and screens fail to identify and properly mitigate all of the anti-competitive effects of such transactions. Additionally, the currently accepted quid-pro-quo analysis of potential mitigation efforts falls well short of actual and effective mitigation necessary to offset the decreased competitiveness of the market. New processes, procedures and mitigation requirements must be developed and used by the regulatory agencies.

It is proposed that a set of analysis and mitigation regulatory criteria can be developed that will properly identify and mitigate potential anticompetitive effects of purchases of competitive generating assets by vertically integrated, investor-owned utilities operating in a regulated monopolistic environment.

The question that will be answered by this study is “How should acquisitions of generating assets by vertically integrated utilities be overseen in today’s quasi-competitive electric power market?”

Purpose of the Study

The purpose of the study is to research and identify major areas of concern to competition created when distressed generating assets are purchased by vertically integrated, investor-owned utilities operating in a regulated monopolistic environment. A proposed set of new criteria will be developed. Proper support for these new criteria will be based on both good engineering and competitive economic practices and analyses.

The appropriateness and importance of these new criteria will be supported by empirical data obtained through a survey process of industry professionals broadly associated with the issues under study.

Importance of the Study

As more merchant generating facilities are sold, or otherwise disposed of, the potential for market abuse by the purchasers of those facilities increases. To the extent that the merchant facilities are purchased by existing vertically integrated monopolistic utilities, the potential for market power abuse is marked. Any activity that increases a dominant firm, such as a utility's, market share in a small geographic region greatly increases the potential for market power abuse in both the short and long term. Additionally, as utility markets in the US are driven into a more competitive state, this increased market share contributes to problems in developing a competitive marketplace, and in stranded cost recoveries (Durham & Durham 1999).

As existing regulatory procedures do not adequately address the issues surrounding acquisitions of merchant generating facilities by utilities, new processes, procedures, guidelines and mitigation requirements need to be developed. This study proposes and discusses industry reaction to new guidelines that address both the current and future issues relating to these acquisitions.

Scope of the Study

There are many diverse interests associated with purchases of generating assets by regulated utilities. Stakeholders in such a transaction include, but are not limited to:

- Stockholders of the utility.
- Stockholders or other owners of the generating facility.
- Retail customers (ratepayers) of the utility.
- State regulatory agencies.
- Federal regulatory agencies.
- Owners of competitive generating facilities in the utility's control area.

- Wholesale customers of the utility or competitive generators.

A study of the impacts to all of these stakeholders would be too broad for this venue. This study will focus on the regulatory treatment of such proposed acquisitions. Specifically, processes and procedures to be employed by the Federal Energy Regulatory Commission will be the primary focus of this study. Necessarily, the impacts to state agencies, competitors, customers and stockholders will be briefly addressed. These, however, are secondary topics and are only included to support the proposed modified criteria and processes developed through this study.

The purpose of this study is to provide the bases and foundations for modified regulations, and to gauge reaction of industry professionals to proposed regulations. Development of a full set of regulations is beyond the scope of this study. Instead, foundational practices, processes and mitigation efforts are developed and proposed.

Rationale of the Study

A proposed set of regulatory guidelines will be developed and proposed. The key points of these proposed guidelines will be distributed to key industry professionals, along with a seven question survey relating the importance and appropriateness of the guidelines. Responses from the survey will be analyzed and discussed.

Definition of Terms

1. *Available Transmission Capacity (ATC)* – Calculated by subtracting the amount of reserved transmission capacity from Total Transmission Capacity. ATC is a measure of the amount of transmission service that is still *available* between two points for use by market participants after all existing agreements have been taken into account.
2. *Control Area* – A geographic region where a utility controls the balance of generation and load on an instantaneous basis. It is also the area where a vertically integrated, regulated utility has the right and obligation to serve retail customers. This right does not extend to wholesale purchasers of energy for resale.
3. *Cost Based Rates* – Rates that are determined through a regulatory process to give a specified return on the investment in fixed assets by utilities. Rates are based on the cost of the fixed asset and the cost of operating those assets.
4. *Energy Affiliate* – A participant in the energy market that has a business relationship with a utility.

5. *Exempt Wholesale Generators (EWG)* – A special class of generation market participant created by the Energy Policy Act of 1992 (EPAct). EWG are defined as “any person [or entity] determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly ... exclusively in the business of owning or operating ... all or part of one or more eligible facilities and selling electric energy at wholesale” (US Congress 1992).
6. *Federal Energy Regulatory Commission (FERC)* – The agency set up by the United States federal government to oversee and regulate interstate commerce in the energy industry.
7. *Herfindahl-Hirschman Index (HHI)* – An index of market concentration calculated by squaring the market share of all participants and summing the results.
8. *Horizontal Market Power* – The ability of a market participant to take action in a segment of the market that results in increases in profits above the competitive level for that firm in the same segment of the market. When applied to this study, it is the ability of a utility to control generation in order to increase the utility’s profits in the generation market.

9. *Independent System Operator (ISO)* – An expanded case of an RTO. An ISO not only plans and operates the transmission system; it also accepts bids for generation to enter a competitive market, and dispatches that generation according to market rules.

10. *Jurisdictional Facility* – A piece of the electric system that falls under the jurisdiction of the Federal Energy Regulatory Commission (FERC). Currently, all parts of the electric system except those owned by governmental agencies or rural electric co-ops are, in effect, jurisdictional facilities.

11. *Market Based Rates* – Refers to charges for electric energy that are determined as a result of a competitive marketplace, as opposed to being set by regulation.

12. *Market Concentration* – The condition where market share, and the subsequent market power, is focused, or concentrated, on a few firms. Higher market concentration generally leads to less competition.

13. *Merchant Generating Facility or Merchant Power Plant*– An electric generating facility that operates primarily for the purpose of selling its energy production to a third party. In contrast, a

utility generating facility operates for the purpose of supplying energy to load served by the utility that owns the plant.

14. *Mitigation* – Under FERC rules, action(s) undertaken by entities seeking approval of a transaction designed to offset anti-competitive effects of the transaction.
15. *Oligopoly* – A market that exists in the region between a pure monopoly and perfect competition. In an oligopoly, there are only a few firms that provide products or services to consumers.
16. *Perfect Competition* - Perfect competition exists when there are a multitude of firms that offer homogenous products or services, and each firm acts strategically in order to obtain market share from other firms. There is no dominance by a single firm, or a group of firms, and there are no significant barriers to entry.
17. *Pure Monopoly* – An economic market in which there is only one supplier of goods or services.
18. *Qualifying Facility* – A power generating facility that meets the fuel, efficiency and reliability requirements of FERC (at least 42.5% efficiency), and is owned by an entity that is not primarily in business to generate and sell electric power, except for power generated solely from Qualifying Facilities (US Congress, 1978).

19. *Regional Transmission Organization (RTO)* – An independent body, set up under FERC jurisdiction that plans and operates the transmission systems of utilities across a broad area of the country, encompassing several control areas. RTOs were established and further defined by FERC Order No. 2000.
20. *State Regulatory Commission* – A body established by a state government to oversee a utility's actions that relate to how those actions impact retail customers in the state.
21. *Stranded Costs* – Investment in fixed assets that the utility made expecting a regulated rate of return, for which compensation should be made when the market transitions to competition.
22. *Total Transmission Capacity* – The amount of transmission service that is available between two points on the transmission grid.
23. *Transmission System* – The network of overhead and underground lines, substations, transformers, and control facilities that serve to transport electric energy from the generating plant to the local distribution system. Transmission system voltages typically fall between 69 kV and 765 kV.
24. *Utility* – As used in this text, a utility is a vertically integrated, regulated entity that owns generation, transmission, and

distribution assets for the delivery of retail electric energy to a customer. The utility is regulated in its retail actions by a state regulatory commission, and thus has a monopoly right and obligation to serve retail customers in a particular geographic area.

25. *Vertical Market Power* – The ability of a market participant to take action in one segment of a market in order to increase the firm's profits above the competitive level in another segment of the market. As applied to this study, it is the ability of a utility to take action in the transmission market in order to disadvantage competitors and increase the utility's profits in the generation segment of the market.

26. *Wheeling* – The transportation of electric energy from one utility to another utility utilizing a physically intermediate utility's transmission system. e.g. Energy moving from Nebraska to Oklahoma would "wheel" through a utility in Kansas' transmission system.

Case Study, FERC Docket EC03-131-000 Acquisition of Interest in NRG McClain Facility by Oklahoma Gas and Electric

Background

In order to further expand the reader's understanding of the topics under study, the particulars of a unique case will be examined in order to show the deficiencies of the current system. The case is unique in that it represents the first time that a vertically integrated utility operating in a regulated monopoly attempted to gain Section 203 approval from the Federal Energy Regulatory Commission (FERC) for the purchase of an independent merchant generating facility located in its own control area.

FERC decisions are based primarily on precedence in previous cases. This precedence acts as the combined historical knowledge of previous commissions on interpretation of the FERC rules and regulations. This historical knowledge, or experience, can offer insight into the proper analyses, processes and procedures that have been applied in the past and could be applied again under similar circumstances. Experience alone, however, offers little insight into the proper handling of a circumstance that has yet to be experienced. Proper treatment of a case that offers unique situations demands thinking that extrapolates beyond precedent, or historical knowledge, and applies broad concepts rather than rigid rules.

Unlike previous similar cases, the McClain generating facility was operating as a direct competitor to the utility prior to the purchase agreement. Recent cases involving purchases of generating assets by utilities involved utilities either purchasing generating assets from affiliated, non regulated entities, or purchasing generating facilities located in other utilities' control areas. While these purchases raise their own level of concern, they are significantly different in their impacts on both current and future competitive markets.

Case History

Oklahoma Gas and Electric Company (OG&E) is a vertically integrated, investor-owned utility operating in Oklahoma. OG&E operates in a regulated monopoly environment under a retail franchise granted by the Oklahoma Corporation Commission. OG&E's control area, where it has a retail monopoly, is shown in Figure 2. The market for wholesale purchases of electricity operates under a form of market-driven competition, based on a tariff required under FERC Order 888 (FERC 1996a). In theory, then, sale of electricity to wholesale customers can be made by any entity wishing to do so. In practice in the OG&E control area, OG&E still made 100% of the wholesale energy sales both prior to and subsequent to the case under review.

NRG McClain, LLC (NRG), a subsidiary of NRG Energy, LLC, owned and operated a power generating facility in Newcastle, Oklahoma (McClain Facility). The McClain facility is a natural gas fired, combined-cycle generating facility utilizing state of the art technology. The plant is capable of operating at an efficiency rate twice as high as a typical utility plant owned and operated by OG&E.

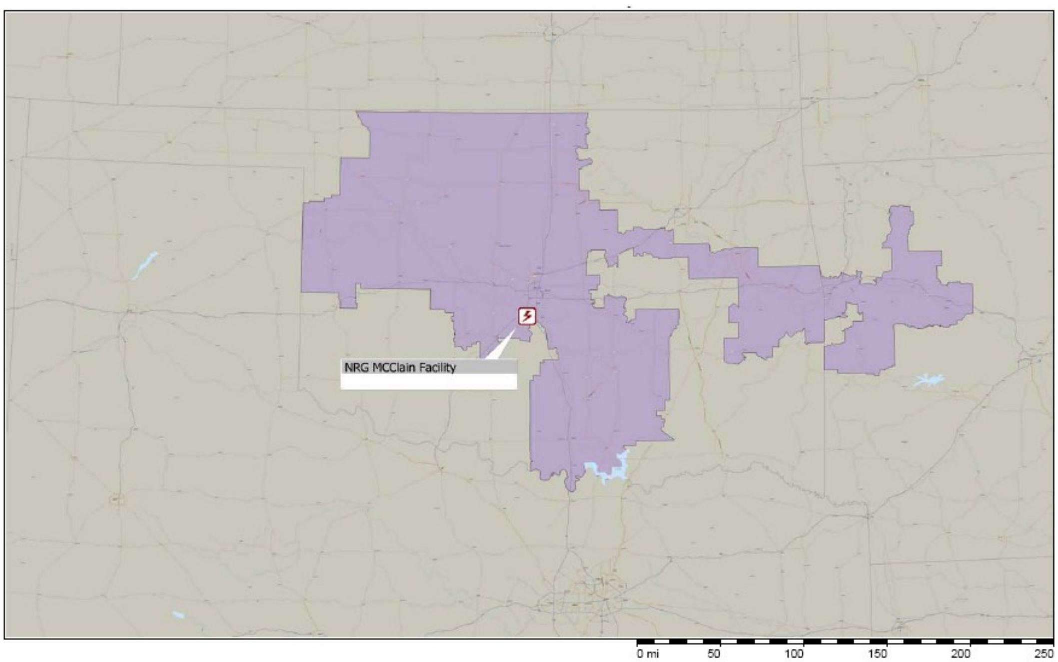

Figure 2 - OG&E Control Area

Construction on the plant was completed in 2001. Figure 1 shows the location of the McClain Facility, firmly within the confines of the OG&E

control area. The McClain facility is capable of generating approximately 520 MW of electric power in a highly efficient form.

On May 14, 2003, NRG Energy, LLC filed for Bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. NRG McClain, LLC did not file for bankruptcy at that time. On August 18, 2003, Oklahoma Gas and Electric Company (OG&E) and NRG McClain, LLC (NRG) entered into a purchase agreement whereby OG&E would acquire NRG's 77% undivided interest in the McClain Facility. The other 23% interest in the McClain Facility is owned by the Oklahoma Municipal Power Authority (OMPA). OMPA is also OG&E's largest wholesale customer. The asset purchase agreement resulted in a net acquisition by OG&E of 400 MW of generating capacity (77% of 520 MW).

On August 19, 2003, as part of the purchase agreement between NRG and OG&E, NRG McClain, LLC filed for bankruptcy protection under Chapter 11 of the US Bankruptcy Code. According to OG&E's report to stockholders, the purpose of this bankruptcy filing was to "facilitate the transaction contemplated by the asset purchase agreement between NRG McClain and OG&E" (OG&E 2004). It is important to note that, prior to the asset purchase agreement between OG&E and NRG McClain, the McClain facility was attempting to operate as a competitor to OG&E's own generation for sales to wholesale customers. Thus, though the facility was distressed because of its inability to penetrate the wholesale power market, it was not presumed to be an unused asset, and in danger of leaving the market.

On August 26, 2003, OG&E and NRG McClain, LLC filed a joint application pursuant to Section 203 of the Federal Power Act requesting Federal Energy Regulatory Commission authorization for OG&E's purchase of NRG McClain's 77% interest in the McClain Facility. FERC reviewed the application pursuant to the Merger Policy Statement (FERC 1996c) and Order No. 642 (FERC 2000c) and found that, unless adequately mitigated, the Transaction would undermine competition and thus not be consistent with the public interest. (FERC 2003c)

Specifically, the Commission found that OG&E's proposed acquisition would increase OG&E's horizontal market power by increasing market concentration and its vertical market power by giving OG&E an increased incentive to withhold transmission capacity to frustrate competition in wholesale markets (FERC 2003c). Accordingly, on December 18th, 2003, the Commission directed that "a public hearing should be held to address the appropriate mitigation for Applicants' proposed disposition of facilities." (FERC2003c)

Throughout the spring and early summer of 2004, prefiled testimony was submitted by OG&E, FERC Staff, and intervenors representing other merchant generating facilities located in the OG&E control area. The emphasis of the OG&E and Staff testimony was to apply existing guidelines, developed for use in evaluating mergers of two disparate utilities. The emphasis of testimony by the intervenors was to address the actual market conditions resulting from the proposed acquisition, and to apply more stringent analyses and guidelines appropriate to a marketplace transitioning from a regulated monopolistic environment to a market-driven competitive environment.

On July 2, 2004, before a full hearing could be held, the Federal Energy Regulatory Commission entered an order approving the acquisition contingent upon several mitigation efforts that must be undertaken by OG&E. Despite the uniqueness of the transaction, and the substantial effects on the competitiveness of the market, FERC's conditions on the acquisition followed the existing merger guidelines, and thus did not address the realities of the current marketplace. In evaluating the OG&E transaction, FERC was hamstrung by an inadequacy of appropriate evaluation techniques, tools and methods to appropriately mitigate the anti-competitive effects of the proposed transaction. The transaction was subsequently completed on July 9, 2004.

Need for Changes to Regulatory Process

In recognition of new dynamics in the marketplace, and the need to develop new standards and guidelines for evaluating transactions such as the OG&E acquisition, FERC initiated a rulemaking process, FERC Docket PL04-9-000, regarding the "Acquisition and Disposition of Merchant Generation Assets by Public Utilities." The first step in this process, a public technical conference, was held on June 10, 2004. While the results of this rulemaking process were not implemented in time to properly evaluate and mitigate the anti-competitive effects of the OG&E transaction, this process will provide a forum for interested parties, academics, and the FERC staff to develop appropriate measures for future transactions.

CHAPTER 2 REVIEW OF RELATED LITERATURE

Introduction

The basis of any new regulatory procedure or practice is, in large part, existing regulations and precedent. New situations, however, require modified thought processes. The study scenario, acquisition of merchant generating facilities by the dominant utility in the control area, is a new phenomenon.

In order to support the proposed new processes, procedures and mitigation efforts, a review and discussion of recent regulatory orders issued by FERC that have bearing on this topic is appropriate. It is also necessary to engage in a quick review of economic theories that attempt to describe the market impacts of such a transaction. This chapter will examine these topics, as well as industry and academic literature that touch on the foundations of such acquisitions. Finally, a proposed set of regulatory practices, procedures and analyses will be developed and discussed.

Much of what has been written on the topic of study has, necessarily, been submitted as part of the regulatory processes and procedures at the Federal Energy Regulatory Commission and state regulatory agencies. Although there have been substantial discussions and publications dealing with the topic of competition in the utility industry, academic input on the specific study topic has, to date, been limited. The large majority of Academic comment on the topic of study has been confined to the regulatory process.

When it is useful for clarification, portions of the case study are included as examples during the literature review discussion.

Regulatory Agencies

There are two primary regulatory arenas that have oversight of the purchase of a generating facility by a vertically integrated investor-owned utility. These two bodies, the state public utility commission and the Federal Energy Regulatory Commission, are interested in different and often conflicting results. While both bodies, theoretically, are charged with protecting the consumer, the methods, practices, and emphases of the organizations is significantly different. While the federal agencies, such as FERC, are interested primarily in protecting competition (FERC 1996a, FERC 1996c, FERC 1999, FERC 2003c) , the state agencies are charged with examining a proposed transaction to ensure that it is “prudent”, or in the interest of the utility’s current ratepayers in a monopolistic environment. These federal and state interests often conflict.

FERC Jurisdiction

The sale of an electric generating facility is, in most cases, regulated by the Federal Energy Regulatory Commission (FERC) under authority granted by Section 203 of the Energy Policy Act. FERC is charged under this section with ensuring that transfers of “jurisdictional facilities” (facilities that fall under FERC jurisdiction) are “in the public interest” (Congress 1977). The criteria used by FERC for examining these transactions to ensure that they are in the public interest are based on Department of Justice / Federal Trade Commission standards (FERC 1996c). These measures were originally developed to examine the impact on competition by a merger of two utilities operating in different control areas. This is a significantly different scenario than that of a monopolistic utility purchasing a generator that is a direct competitor with the utility in the same market.

While two utilities operating in different control areas compete with each other at some level, the level of impact on the competitive market is significantly less than an acquisition that takes place inside the same control area or market. The FERC processes and procedures historically used to examine these types of transactions are inadequate to examine the impacts to both current and future competition of these types of transactions.

Significant Federal Regulation

The Federal government has been regulating the electric power industry since the mid 1930's. From that time until the late 1970's, there were no significant changes in the way that the power industry was overseen by the federal government. During the mid 1990's, and the following decade until the preparation of this study, significant changes have taken place. Significantly, these alterations have all favored increased competition and increased federal involvement in assuring that utilities are not allowed to unduly disadvantage competitors in the market. In order to provide a basis for the modifications to the regulatory processes that are proposed in this study, a review of significant federal regulation will be presented.

Initially, a history of regulation, emphasizing changes that benefit competition, will be presented. This will be followed by a review of two FERC orders (Order 592 and Order 642) that deal with merger of utilities. It is the process outlined in these orders that FERC has transferred over and applied to its review of utility acquisitions of rival generating facilities.

Federal Power Act

Initial passage of the Federal Power Act was in 1935. At the time, there were only a handful of power companies that controlled the entire electrical power market (Durham & Durham 1997). The Federal Power Act granted authority for review and oversight of these electrical utility holding companies to the United States Securities and Exchange Commission (SEC) and the Federal Power Commission. Not only were the SEC, and the newly formed Federal Power Commission, able to review and give approval to financial transactions of these holding companies, these agencies were able to exercise unprecedented control over the structure, operational procedures and business practices of the entire electric industry. No peacetime regulation had granted such wide-ranging authority to a federal agency (Durham & Durham 1999).

The Federal Power Act was significantly rewritten by the sixty-sixth United States Congress in 1977. This legislation granted certain regulatory authority over electric utilities to the Department of Energy, who in turn assigned that authority to the Federal Energy Regulatory Commission (FERC). While a comprehensive review of this legislation is well beyond the scope of this study, it is useful to examine the impacts that some sections of the law had, and are having, on the relationship between merchant generating facilities and electric utilities, specifically as it relates to the acquisition of a merchant facility by a utility.

Section 203 of the Federal Power Act gives FERC the authority to oversee and approve mergers, transfers or consolidations of jurisdictional facility assets in excess of $50,000 (US Congress 1977). The term jurisdictional facility, as used in this regulation, refers to any asset that falls under the regulatory control of FERC, or is authorized by federal law and FERC regulations. Not only does this include public utilities and their transmission, generation and other assets, it also includes privately owned facilities such as merchant plants, Qualified Facilities authorized under the Public Utility Regulatory Policy Act (PURPA), and even contracts owned by power marketers. In effect, the scope of jurisdictional facilities is broad enough to encompass all but a very small part of the electric utility system in the United States. The parts excluded are primarily publicly owned utilities, such as municipalities, or cooperative owned facilities, such as rural electric co-ops.

Of the FERC orders that pertain to this study, several were made under the authority granted the Commission under Section 203. These include FERC Order No. 592 (FERC 1996c), FERC Order No. 642 (FERC 2000c), and several orders in individual cases such as the OG&E / McClain case that is described as part of this study (FERC 2003c).

Section 205 of the Federal Power Act gave FERC authority to oversee and set rates for utilities that use their transmission system to move electric energy, or that make electric energy sales that are overseen by FERC (US Congress 1977). In practice, FERC regulations and court decisions have held that this authority applies to all wholesale sales and purchases of electric energy by public utilities, whether those purchases are made inside or across state boundaries (FERC 1996a, FERC 1999).

It is section 205 of the Federal Power Act that FERC has used as a basis for regulatory authority in the issuance of its orders regarding increased competition in the electric utility market. Federal Regulations, as they pertain to this study, issued under authority of Section 205 include FERC Order No. 888 (FERC 1996a), FERC Order 889 (FERC 1996b), FERC Order No. 2000 (FERC 1999), FERC Order No. 2000-A (FERC 2000a), FERC Order No. 2003 (FERC 2003a), FERC Order No. 2004 (FERC 2003b) and FERC's Order on Generation Market Power Analysis (FERC 2004a).

Section 209 of the Federal Power Act gives FERC authority to refer any matter that affects states, or state regulation of utilities, to a board of members from those state(s) that are affected. These boards are vested with the full power and authority of the Commission, on the referred matter. Section 209 also states that, when it can do so without prejudicing ongoing FERC proceedings, FERC will provide experts to the states to aid states in the regulation of public utilities (US Congress, 1977). The authority that FERC has to refer matters involving states to representatives of the state is fundamental to the new regulatory processes and procedures proposed as part of this study.

Section 210 of the Federal Power Act gave rise to a new breed of electric energy market participant, the Qualified Facility (QF). Specifically, Section 210 required that any "electric utility, Federal power marketing agency, geothermal power producer (including a producer which is not an electric utility), qualifying cogenerator [QF], or qualifying small power producer" that desires interconnection with an electric utility may request FERC to issue an order requiring the electric utility to grant such an interconnection (US Congress, 1977).

In effect, Section 210 of the Federal Power Act was the first step in opening the utility system to competition, since it allowed non-utility entities to interconnect with the utility controlled transmission system. This section also permitted FERC to issue an order forcing utilities to sell auxiliary power to interconnected utilities (US Congress, 1977). Section 210 paved the way for passage of the Public Utilities Regulatory Policy Act (PURPA) of 1978 that further expanded the rights and roles of Qualifying Facilities.

Public Utilities Regulatory Policy Act of 1978 (PURPA)

Congress further expanded the roles of qualifying facilities with the passage of PURPA legislation. This legislation modified the Federal Power Act regarding rates paid by utilities to Qualified Facilities that are permitted interconnection under the Federal Power Act. PURPA required FERC and state commissions to develop regulations whereby Qualified Facilities would be able to sell electric energy to the utility at a cost not to exceed the utilities' avoided cost of created electric energy (US Congress 1978).

Under PURPA, utilities would have an obligation to purchase such power when it is offered at rates not above this avoided cost (US Congress, 1978). Payment is made to the QF in two ways: a capacity payment, which is a fixed periodic amount, based on the installed rating of the QF, and an energy payment, which is made based on the amount of electric energy actually generated by the QF and sold to the utility.

The purpose of PURPA was twofold. First, it was designed to encourage efficient use of resources. In order for a generating station to meet the criteria of a Qualified Facility, it had to meet a minimum 42.5% thermal efficiency level (UIC 2002). At the time of passage of PURPA, utility plant efficiencies (large gas fired or coal fired steam boilers) averaged around 28% thermal efficiency (UIC 2002).

Most QFs meet the stringent efficiency requirements by generating steam from the waste heat exhausted from the power generating cycle. The steam is then sold to a steam host, such as a refinery, which uses steam in its own processes. Thus, while the thermal efficiency of the power generating plant proper was less than required, thermal efficiency of the entire process, including steam generation, was well in excess of the requirements. Modern power generating facilities, utilizing the latest combined cycle operations, can generate electricity at thermal efficiencies nearing 49%, without a steam host. Most merchant generating facilities constructed in the late 1990s and early 2000s generate electricity in this range of efficiency.

Secondly, PURPA was designed to encourage competition in the electric energy industry. Since, in most utility control areas, the avoided cost of electricity is based on construction of a new utility power plant, the payments by utilities to the qualified facilities have, in general, favored the generators of electricity.

The Public Utilities Regulatory Policy Act (PURPA) has recently come under criticism due to the fact that avoided cost estimates developed in the 1980s and early 1990s have turned out to be higher than actual costs. Since most PURPA qualifying facilities locked in rates by signing long-term contracts with the utilities, payments to QFs, it is argued, have caused ratepayers to have higher utility bills than necessary. Sections of PURPA dealing with avoided cost payments have been targeted for repeal.

What is missed in arguments against PURPA, however, is that without these QFs, utilities would have constructed power generating facilities utilizing then-existing technology. Utilities would have gained a return, per state regulation, on the investment in these facilities. Thus, long-term fixed cost payments by ratepayers would have been similar to payments made to QFs for capacity. The fuel cost of generating energy in these utility plants, however, would have met or exceeded energy payments to the qualifying facilities, due to the lower efficiency levels of the utility plants.

During the next two decades, FERC policy regarding competition remained basically unchanged. Other than the provisions made for qualifying facilities under PURPA, utilities were allowed to operate under the same regulated, monopolistic environment that had existed since the mid 1930s (FERC 1996a). This environment began a drastic and relatively rapid change in 1992 with the passage of the Energy Policy Act.

Energy Policy Act of 1992

The legislative session of 1992 brought about the most significant changes in the utility industry to date. The Energy Policy Act of 1992 (EPAct) amended the Public Utilities Holding Company Act of 1935 and the Federal Power Act in three key areas: free access to transmission, wholesale generation, and ownership in foreign utilities (US Congress 1992).

Much of the public attention has been focused on the changes to the code that affect transmission. Changes resulting from this portion of the legislation have been popularly referred to as regulations on “wheeling”. Wheeling is the movement of electricity from one utility system to another, through another system which is geographically interposed between the two. For example, were a utility in southern Nebraska to sell electricity to a customer in Northern Oklahoma, it would have to “wheel” the power through an intermediary in Kansas (Durham & Durham 1997).

The EPAct required that utility systems provide ‘open access’ to their transmission assets (US Congress 1992). According to the Federal Energy Regulatory Commission this should “eliminate the transmission market power of public utilities by ensuring that all participants in wholesale power markets will have nondiscriminatory open access to the transmission systems of public utilities"(FERC1996a). These rules have attempted to open the transmission market to freer competition.

The second area which was addressed was the area of wholesale generation. A new class of players in the utility market was created. The code refers to this new class as 'Exempt Wholesale Generators' (EWG). An EWG is defined as "any person determined by the Federal Energy Regulatory Commission to be engaged directly, or indirectly ... exclusively in the business of owning or operating ... all or part of one or more eligible facilities and selling electric energy at wholesale" (US Congress 1992).

The key point is that Exempt Wholesale Generators are not considered to be a public utility company (US Congress 1992). Effectively, this allows anyone to own or operate a generating facility and offer the power for sale to any buyer, without the necessity of adhering to the stringent regulations imposed on public utilities (Durham & Durham 1999). In addition, holding companies which are regulated under the Public Utility Holding Company Act are not prohibited from owning or operating an EWG.

One viable scenario is a new company coming into an area and building or buying a generating facility, selling the power to wholesale customers. Another, more refined scenario is an existing public utility owning and operating a facility in a competitor's territory, thus directly competing in the generation market.

A speed bump which was placed in the act is that no EWG can enter into a contract with an affiliate or associate company for the purchase of power, unless such sale is approved by all state commissions having jurisdiction. This effectively prevents existing utilities from un-bundling generation assets and entering into full fledged wholesale competition. The result is a less competitive marketplace.

The tenets of the Energy Policy Act of 1992 were promulgated into regulations by FERC beginning in 1996 with FERC Order Nos. 888 and 889.

FERC Order No. 888

The initial FERC order that strongly moved federal regulation to that of promoting competition in the utility marketplace was FERC Order No. 888 titled *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Final Rule*. Order No. 888 was issued in April of 1996. The purpose of this final rule was twofold. First, it attempted to address "undue discrimination" regarding which entities had access to the utility's transmission system.

Secondly, Order 888 attempted to address recovery, by utilities, of so-called "stranded costs", or investment that the utilities had made with the expectation of being able to receive a guaranteed return under the regulated, monopolistic system that was in place (FERC 1996a).

Of most interest to this study is the portion of FERC Order No. 888 that addressed access to the transmission system. FERC found that, despite regulations put in place under Section 205 of the Federal Power Act, portions of the monopoly owned utility transmission system were not open to access by merchant generators or other third parties (FERC 1996a). FERC also found that utilities were giving preferential rates and treatment to their own, or affiliated, generating stations for use of the transmission system. This situation created an uneven playing field, where potential competitors of the utility could not access a vital portion of the energy delivery system.

FERC Order 888 required utilities to develop a standard tariff, or rate, charged for transmission service. This tariff was required to be the same for all users of the transmission system, whether they are other utilities, independent third parties, or affiliates of the utility. The utility, as well as any other potential users of the transmission system, would be required to acquire transmission service for its own wholesale sales of electricity under the standard tariff (FERC 1996a).

The significance of Order 888 is that, in theory, all players in the wholesale generating market would have equal, non-preferential access to the transmission system. Although further regulation, in the form of FERC Orders 2000, 2003 and 2004, was required to further realize this goal, FERC Order 888 was the first step in opening the historically monopoly-controlled transmission system to some form of competition. This access is critical to the criteria and modified processes proposed as part of this study.

FERC Order 889

As part of the tariff administration, utilities were required to develop real-time open access information systems (OASIS), for public sharing of information regarding administration and for access to the transmission system under the tariffs imposed per Order No. 888 (FERC 1996b). The implementation of OASIS systems is detailed in FERC Order 889, entitled *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, Final Rule*. Key requirements of the OASIS systems are that information is to be provided electronically, most often by the World Wide Web, and that the information is to be provided on a real-time basis (FERC 1996b).

In addition to the information systems, Order 889 required utilities to develop and adhere to standards of conduct that functionally separated the transmission function of the utility from the generation function (FERC 1996). This requirement was designed to ensure that outside parties seeking access to the transmission system were on equal footing with internal users. Functional separation, it was thought, would prevent preferential treatment of a company's internal generation resources. As with the goals of Order No. 888, further regulation was developed in order to more realistically meet the goals of Order No. 889.

Prior to the implementation of Order 889, information about the transmission system was in the exclusive domain of the utilities. FERC Order No. 889 marks the first federal regulation that attempted to develop the transparency in utility operations that is vital to the establishment of competition. The proposed criteria expands on this transparency feature by widening its application to include purchases of wholesale energy by the utility from affiliated, but functionally separate, generating facilities, and the subsequent use of the transmission system.

FERC Order No. 2000

Having found that functional unbundling and implementation of standard, open-access tariffs (under the regulations promulgated in

Orders 889 and 888 respectively) were not sufficient to encourage non-preferential access to the transmission system, FERC issued Order No. 2000 *Regional Transmission Organizations, Final Rule.* This order requires utilities under FERC jurisdiction to make filings regarding development and participation in Regional Transmission Organizations (RTOs) (FERC 1999). Although the filings are required, actual participation in RTOs, under Order No. 2000, is still voluntary. This is consistent with the Commission's history of incremental regulation.

RTOs are independent entities, outside the direct control of the utilities, that plan and operate the transmission system on a regional, rather than a control area by control area, basis. Utilities, once they become members of the RTO, turn over full operational control of the transmission system to the RTO. According to the Order, RTOs were expected to be in place by December, 2001. Specifically, Order No. 2000 mandated the following requirements for an RTO to be approved by the commission (FERC 1999):

Minimum Characteristics:

1. *Independence* – The RTO must be completely independent of the utilities that formed it, or of other market participants. This requirement extends to the ownership interest and the board of

directors for the RTO. This requirement precludes undue control over the RTO by a market participant, or *class* of market participant (such as utilities or merchant generators).

2. *Scope and Regional Configuration* – The RTO must be large enough to gain the benefits of regional planning and control (rather than a single control area), but must be small enough so that the issues addressed by the RTO are interrelated, and are appropriate to be dealt with on a regional rather than a national basis.
3. *Operational Authority* – The RTO must have full operational control over the transmission systems. Utilities cannot be allowed to maintain control over pieces of the system that would allow them to exercise preferential treatment or undue discrimination.
4. *Short-term Reliability* – The RTO would have the responsibility to maintain reliability of the transmission system. To implement this, the RTO would have authority over any interchange schedules, or over transfer of power between control areas; would have authority to redispatch any generator connected to the transmission system in order to maintain reliability; and would have final approval authority over transmission

maintenance scheduling. The commission concluded that there were benefits to the RTO having approval authority over generation maintenance scheduling, but that authority is not necessary in order to maintain reliability, and was not provided under this order.

Minimum Functions:

1. *Tariff Administration and Design* – The RTO must create and enforce the tenets of a non-discriminatory, standard, open-access tariff so that all market participants incur the same charges for use of the transmission system.
2. *Congestion Management* – The RTO must develop processes and procedures to reduce or eliminate effects that congestion in the transmission system has on the market. Congestion pricing information can give vital information regarding where to expand in order to reduce congestion (Hirst & Kirby 2001).
3. *Parallel Path Flow* – The RTO must develop processes and procedures to eliminate, to the extent possible, market effects of parallel path flows, and to prevent market participants from taking advantage of parallel path flows to inappropriately gain tariff revenue when no actual power transfer has taken place.

4. *Ancillary Services* – The RTO must serve as a supplier of last resort for ancillary services such as reactive power, voltage support, balancing energy and the like.
5. *OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)* – The RTO has responsibility for calculating and posting electronically the total amount of transmission capacity in the transmission system and the amount of transmission capacity that is available for reservation under the tariff.
6. *Market Monitoring* – The RTO must establish an independent entity responsible for auditing and investigating market participants to ensure that market participants are not inappropriately exercising market power, or violating the rules and procedures of the RTO.
7. *Planning and Expansion* – The RTO would have primary planning and decision making authority to determine what, where and when construction of new transmission facilities take place. This includes not only historical transmission facilities, but also includes providing information as to desired generation siting alternatives that would reduce congestion (Hirst & Kirby 2001).

8. *Interregional Coordination* – The RTO would have the responsibility of coordinating communications and activities with neighboring RTOs or ISOs to ensure overall reliability of the national transmission system.

By removing control of the transmission system from entities (utilities) that have affiliate relationships with wholesale generator providers (users of the transmission system), preferential treatment of affiliated generators is precluded. RTOs have the additional benefit of increasing efficiency in the electric system by encouraging competition resulting in lower prices. RTOs also more effectively address congestion, providing market participants with better access to the transmission system, more accurate capacity calculations, and more efficient planning of transmission expansion across control areas (FERC 1999). In fact, one of the most significant impacts of FERC Order No. 2000 are the comments the Commission made that, for the first time, strongly lay out FERC's policy as one of increasing competition and customer choice (FERC 1999).

As mentioned above, actual participation by jurisdictional utilities in Regional Transmission Organizations is voluntary under Order 2000. The commission states in the order, however, that, if utilities do not voluntarily form and participate in RTOs, the Commission will determine what additional regulations will be required to encourage non-preferential treatment and competition in the marketplace (FERC 1999).

As of the date of this study, only three regions of the country have successfully formed fully operational RTOs or ISOs (FERC 2000b). These three areas, the New York ISO, ISO New England and the Pennsylvania–Jersey–Maryland (PJM) ISO are all located in the Northeast corridor of the United States, and encompass only those states from Maine to Kentucky. Figure 3 shows the area served by these entities.

FERC jurisdictional utilities in other parts of the country have not formed fully operational RTOs (FERC 2000b). Thus, these regions of the country do not have the benefits associated with RTOs. It is in these areas of the country that do not have operational RTOs that there is the potential for market abuse when utilities purchase distressed merchant facilities. In areas where fully functional markets are present, the procedures and processes proposed in this study are not required.

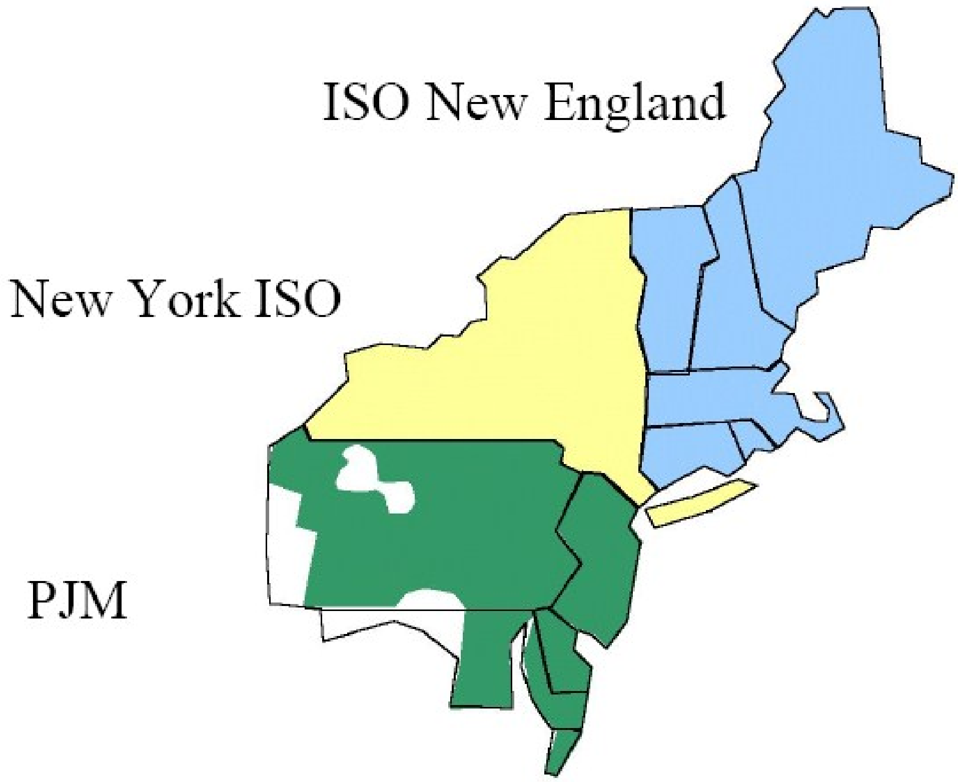

Figure 3 - Northeast Corridor ISOs/ RTOs

FERC Order No. 2003

It was thought by FERC at the time of rules promulgation under Order No. 2000 that full, voluntary cooperation with the tenets of an RTO would allow free, unfettered access to the transmission system by any willing party. This turned out, however, to be overly optimistic. Not only was the formation and operation of RTOs significantly delayed beyond the December 2001 timeframe that FERC laid out in Order 2000, but utilities also developed arbitrary and inconsistent standards for third party generating facilities attempting to connect to the utility's transmission system.

Most significantly, transmission providers in most parts of the country would require generating facilities desiring interconnection to not only pay for the connection to the transmission system, but also pay for any upgrades to the transmission system that were necessary as a result of the generator connection. The utility, then, would roll the cost of the transmission upgrades into its tariff structure, *and* charge the generator for use of the transmission system, including the facilities for which the generator provided funding (FERC 2003a).

This "and" pricing structure was found by the Commission to provide undue discrimination that favored affiliated generation at the expense of non-utility plants. Specifically, when utilities would construct, or purchase, a generating facility, costs for the transmission upgrades were borne by all customers by inclusion into the rate base. The affiliated generator did not directly fund those costs. Since third-party generators would fund the costs of expansions for their plants (*and* then get charged for the use of them), these generators would be at an economic disadvantage when attempting to compete with utility affiliated generators (FERC 2003a). These issues were addressed in FERC Order No. 2003

Standardization of Generator Interconnection Agreements and Procedures.

The Commission attempted to remedy this discriminatory pricing policy by implementing standard Large Generator Interconnect Procedures (LGIP), and a standard Large Generator Interconnect Agreement (LGIA). According to the Order, a large generator was one that had capacity in excess of 20 MW. In the absence of a fully functioning RTO or ISO in a utility's control area, a utility would be required to amend the standard LGIP and LGIA to their open-access tariff (FERC 2003a).

Under these standard processes, procedures for study and determination of facilities necessary for interconnection and system upgrade would be known in advance by all parties, and could be included in the cost-benefit analysis when siting a new plant. Additionally, and most significantly, FERC mandated that, when transmission facility upgrades are funded by the generator, the amount of funding would be returned to the generator in the form of credits on the generator's transmission tariff obligations. All funds would have to be returned to the generator within a five-year time frame. Costs of interconnection facilities would be borne exclusively by the generator (FERC 2003a).

As an example, suppose that a generator sited a plant near a utility substation. Construction of line and substation facilities to physically connect the generator cost $10 million. Operation of the generating facility, however, would cause overloads on the transmission system in places outside of the physical connection. In order to remedy these overloads, upgrades at a cost of $20 million are necessary. The generator then would be required to pay to the utility $30 million to fund construction of transmission facilities. $20 million would be credited to the account of the generator, who could use the $20 million to pay for transmission service over the next 5 years.

The policies and procedures outlined in FERC Order No. 2003 provide a more equitable distribution of pricing for transmission upgrades. Since all users benefit from the upgrade of the transmission system, it would be inappropriate for one user to unilaterally fund these upgrades. Additionally, the standard procedures outlined by FERC preclude utilities from using the interconnection process to provide preferential treatment to its own, or affiliated, generating facilities. Order 2003 also further encourages competition by allowing generating facilities to recover costs of construction that otherwise would have been sunk into transmission upgrades.

FERC Order No. 2003 has a significant impact on the proposed modifications to regulatory procedures that are the focus of this study. The sharing of the transmission system, and the corporate funding of upgrades, is necessary in order to create a transmission system that is robust enough to serve the competitive dispatch procedure proposed. Additionally, Order no. 2003 encourages construction of competing generating facilities, without which the proposed mitigation efforts would have no effect.

FERC Order No. 2004

Order No. 2004, *Standards of Conduct for Transmission Providers,* codified the Commission's standards of conduct as they relate to transmission providers. Specifically, the rule states that employees of transmission providers must be separated from those of energy affiliates (defined as any entity engaged in any portion of the energy industry that has a business relationship with the transmission provider), and that the transmission provider cannot provide preferential treatment to affiliated energy entities.

The significance of Order No. 2004 by the Federal Energy Regulatory Commission was that it treated all transmission providers, whether they transmit electric energy or natural gas, the same. The natural gas market has been fully competitive for almost 20 years, resulting in significant increases in technology and decreases in overall prices. The electric energy industry, however, has been loathe to move on deregulation.

The promulgation of regulations that cover both entities is a strong signal that, if the electric energy industry does not move toward competition voluntarily, FERC intends to force the issue. It is this intent to move toward competition that is the basis of the proposed modifications to regulatory practices that are the subject of this study.

Having reviewed historical regulations regarding FERC's interest in encouraging competition in the electric power industry, it is necessary to examine three additional FERC regulatory orders. Two of these orders, Order No. 592 and Order No. 642, lay out the current processes and procedures used to determine whether a utility merger is in the public interest. The third, FERC's order on generation market power analysis. confirms the guidelines laid out in 592 and 642, and emphasizes the Commission's emphasis on increasing competition in the utility marketplace. It is these practices that must be modified when applied to the acquisition of merchant facilities by rival utilities.

FERC Order No. 592

In the mid 1990s, FERC developed and issued a policy statement regarding mergers of utilities. This policy statement, embodied in Order

No. 592 *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, codified the processes and procedures that FERC would use to examine whether or not a potential merger was "in the public interest" (FERC 1996c). In large part, the FERC policy statement was based on US Department of Justice (DOJ) and US Federal Trade Commission (FTC) guidelines developed to examine and screen mergers of publicly held companies (FERC 1996c).

FERC, in Order No. 592, established five steps that would be employed to examine the effects of proposed mergers (FERC 1996c). These five steps are listed below:

1. Define affected markets and measure the concentration of competition in those markets.
2. Determine whether level of concentration, or other factors, raises competitive concerns.
3. Determine whether entry into the marketplace by new competitors would be timely and sufficient to deter anti-competitive behavior.
4. Evaluate any efficiency gains that would be created by the merger.
5. Determine whether, in absence of the merger, either firm is likely to fail and remove its assets from the marketplace.

The large majority of the guidelines established under Order No. 592 have to do with horizontal market power, as defined by market concentration. Horizontal market power is defined as the ability of a firm to take action in one market, and increase profits in that market. Relevant to the study parameters, horizontal market power is the ability of an entity (utility) to control generation to the point that they can increase profits in the generation market.

A key tenet of horizontal market power analysis is that as more market share, and the associated market power, is concentrated into a single firm, the more dominance that firm has. A standard measure of market concentration is the Herfindahl-Hirschman Index (HHI). This measure is used by the Department of Justice, the Federal Trade Commission, and the Federal Energy Regulatory Commission to determine the extent of market concentration, the amount of market power held by a firm(s), and the effect that a proposed transaction has on this market concentration and market power.

The Herfindahl-Hirschman Index is calculated by squaring the percentage market share of all participants in the market, and summing these values together (FERC 1996c). For example, suppose a market containing four competitors, with market shares of 60%, 20%, 15%, and

5% respectively. According to the calculations laid out in FERC Order No. 592, the HHI value for this market would be

$$60^2 + 20^2 + 15^2 + 5^2 = 4250.$$

Calculation of the HHI value for a utility market, and the insight that this value gives as to the structure of the market, is a key element to both the current regulations and the modifications to those regulatory practices that are proposed in this study.

Steps 1 and 2 of the Merger Analysis policy established in FERC Order No. 592 require calculations of an HHI value. In step 1, the market under analysis is defined. The most accepted method of doing so is to execute a delivered price test. This process evaluates which competitors could deliver products to the market in question at a cost less than 105% of the typical market clearing price for the market examined. It is important to note that, under the merger guidelines established in Order No. 592 there may be several markets that require examination for a particular merger. These markets may be differentiated by product (firm vs. non-firm energy sales), or they may be differentiated by time or season (summer peak vs. winter off peak) (FERC 1996C).

Once the market is defined, an HHI value is calculated. The level of the HHI value determines the level of concentration that exists in the evaluated market(s). These values are referred to as pre-transaction HHI values.

According to Order No. 592, HHI values of less than 1000 indicate a market that is not concentrated. Market HHI values between 1000 and 1800 indicate a market that is moderately concentrated. HHI values in excess of 1800 indicate a market that is highly concentrated (FERC 1996c).

Once the pre-transaction values have been determined, the values of HHI that will exist in the post-transaction market are calculated. This process involves modeling the market as it would exist after the proposed transaction is completed. Most often this will result in an increase in market share for the newly merged entity. The values of HHI calculated in a post-transaction market are compared to the pre-transaction values to establish the HHI delta, or change, that results from the transaction. A positive HHI delta indicates increased market concentration, while a negative HHI delta indicates that the transaction would de-concentrate the market.

Step 2 of the merger guidelines requires an analysis to be done to determine whether the transaction raises competitive concerns (FERC 1996c). The guidelines accept the DOJ/FTC standards in this regard. With respect to the HHI delta calculated in step 1, the guidelines establish a series of competitive analysis screens to evaluate the potential anti-competitive effects of the transaction. These are listed below:

- In unconcentrated markets (HHI less than 1000), the guidelines assume that the merger will not have an adverse affect on competition.
- In moderately concentrated markets (HHI between 1000 and 1800), HHI deltas in excess of 100 raise significant competitive concerns.
- In highly concentrated markets, HHI deltas in excess of 50 raise significant competitive concerns, while HHI deltas in excess of 100 are presumed to be anti-competitive.

If a proposed merger passes the competitive analysis screen, then the merger is approved by FERC. If a proposed merger fails the competitive analysis screen, then further analysis is warranted to determine what, if any, mitigation is required to offset the anti-competitive nature of the transaction. Most often, this mitigation takes the form of either divestiture of existing assets in order to bring the HHI delta down to acceptable levels, or expansion of the transmission system in order to allow competitors to enter the market or expand their offerings . This is the process outlined in step 3 of the merger guidelines (FERC 1996c). Step 3 also requires new HHI calculations to be performed in order to examine the effects of these changes.

Steps 4 and 5 of the merger guidelines are exceptions to the market concentration analysis described in steps 1 through 3. If the proposed merger offers gains in market efficiency that cannot be obtained through other means, then FERC may approve the transaction regardless of the effect on market concentration (FERC 1996c). This is the evaluation process described in Step 4 of the guidelines.

Additionally, if one of the firms in the proposed merger would fail in the absence of the merger, then that firm's assets would be removed from the market. If FERC determines that the removal of the failing firm's assets from the market would have a more detrimental effect on competition than the increase in market concentration, then the Commission may approve the order, regardless of a failure of the competitive screen analysis (FERC 1996c).

As was noted above, the HHI index and associated guidelines deal primarily, if not exclusively, with horizontal market power issues. An associated area of potential abuse by dominant firms is in the exercise of vertical market power. Vertical market power is defined as an entity's ability to take action in one market, and increase profits above competitive levels in an associated, or downstream market. Pursuant to the case of a utility purchasing a merchant generating facility, a utility's ability and incentive to control the transmission system in order to disadvantage competitive generators, and increase profits for its own generating facilities, is vertical market power.

An increase in the ability or incentive of a utility to exercise vertical market power is almost always a result of an acquisition of a merchant facility by a utility. If for no other reason, a utility's incentive to exercise vertical market power will increase due to the fact that the utility now has additional generation that can benefit from prices that exist above competitive levels (FERC 2003c).

Vertical market power analysis gets very little attention in FERC Order No. 592. It is, however, the primary area of concern that Orders 888, 889, 2000, 2003 and 2004 have dealt with. The establishment and participation by a utility in an approved, functioning RTO as described in FERC order No. 2000 eliminates much of the concern about vertical market power, and subsequent increases in vertical market power. As was mentioned, however, very few regions of the country operate under Regional Transmission Organizations, despite FERC orders that all but require utility membership in an RTO. It is in these areas where RTOs have not been established that the application of the FERC guidelines is deficient in addressing increased vertical market power as the result of acquisitions. The proposed modifications to the regulatory practices address increases in vertical market power that occur as a result of utility purchases of rival generating facilities.

FERC Order No. 642

FERC Order No. 642 attempted to address the deficiencies in Order 592 regarding vertical market power analysis. In effect, the Commission attempted to enact the same basic analysis as described in Order No. 592 regarding horizontal market power analysis. The text of Order 642, subsequently, includes a discussion of the same 5 steps described in Order 592 (FERC 2000c).

What is conspicuously absent, however, is a clear definition of the market to be analyzed. While Order 592 used the delivered price test to determine the geographic size of the horizontal (generation) market, there is no similar test that can determine the market for upstream vertical (transmission) markets. This is primarily due to the fact that monopolistic utilities, by design, operate at near 100% market share in the transmission segment of the market.

Instead of creating a standard procedure for defining a vertical market, the Commission left it up to the applicants, if it appears that vertical market power is a concern, to define the appropriate market, and then conduct the concentration analysis as described in the order (FERC 2000c). It is in the best interest of the applicants, then, to argue that there are no vertical market power effects, and to avoid vertical market power analysis entirely. This is precisely the approach that has been successfully taken in the OG&E / McClain case that is included as a case study in this research.

Vertical market power analysis, then, is not sufficiently addressed in the regulations put forth by FERC. As there are significant vertical market power concerns in cases where utilities propose to acquire a rival merchant generating facility, the proposed modified regulatory practices in this study must address both the horizontal and vertical, or generation and transmission, aspects of such an acquisition.

FERC Order Modifying Interim Generation Market Power Analysis and Mitigation Policy

This order, resulting from dockets of market participants seeking approval of market-based, rather than cost-based, rates has general, if not specific, application to the transactions under study. In this Order, FERC again reiterates its intention to mitigate both horizontal and vertical market power issues. FERC also addresses, and reconfirms, the applicability of market concentration analysis, as measured by HHI, in the evaluation of both horizontal and vertical market power (FERC 2004a).

What the commission again fails to address is the proper definition of vertical markets. Neither does the Commission require that vertical market power analysis be a part of any requests for approval. FERC, instead, again relies on the applicants to determine what, if any, vertical market power analysis should be performed (FERC 2004a).

State Oversight

In addition to the Federal Energy Regulatory Commission, state public utility commissions have oversight over the purchase of assets by regulated public utilities. State public utility commissions oversee the implementation of cost-based rates for the utilities in their jurisdiction. Under a cost-based rate structure, utilities recover the cost of assets used to provide electric energy to customers, plus a “reasonable” fixed return on the investment in those assets. The state commission sets those retail rates that allow the utility to recover investment in the asset as well as receive the utility’s allowed return (Biewald et al 1997).

As utilities make investment into fixed assets, the costs of which they intend to recover and receive a return on through retail rates, the prudency of those purchases must be approved by the state commission.

In the eyes of the state commission, a prudent purchase, according to the Louisiana Public Service Commission is one "that enables utilities to provide customers with safe, adequate and reliable service, at rates that are just and reasonable, equitable and economically efficient, and that allow utilities an opportunity to earn a fair rate of return on their investment". The mandate of the state commissions is to protect the utility's current and future ratepayers, as well as the utility. Under the existing regulated monopoly system competition is neither protected nor promoted (Biewald et al 1997).

Conflict of Regulatory Agencies

An examination of published mission and vision statements for regulatory agencies shows both a similarity in purpose and a difference in practice between the federal and state agencies. To demonstrate, the mission and vision statements of FERC and four (4) representative states will be discussed.

FERC's Mission is stated in their organizational documents, available on the commission's website http://www.ferc.gov/. "The Federal Energy Regulatory Commission regulates and oversees energy industries in the economic and environmental interest of the American public." FERC's vision is "Dependable, affordable energy through sustained competitive markets”. The plethora of FERC orders promoting competitive markets, as discussed above, also show the focus of the federal commission.

The Public Utility Division of the Oklahoma Corporation Commission (http://www.occeweb.com/) states its mission as follows. “The mission of the Public Utility Division is to provide technical support and policy analysis to the Commission in: (1) Assuring reliable public utility services at the lowest reasonable cost; (2) assuring open, workable, competitive markets in the transition to competition; and (3) fulfilling constitutional and statutory obligation.”

Florida Public Service Commission (http://www.psc.state.fl.us/): “Customers are served best by markets that facilitate the efficient provision of safe and reliable utility services at fair prices. The mission of the Florida Public Service Commission is to promote the development of competitive markets – as directed by state and federal law – by removing regulatory barriers to competition, and by emphasizing incentive-based approaches, where feasible, to regulate areas that remain subject to rate of return regulation. Once markets become sufficiently competitive, the Florida Public Service Commission will eliminate regulatory involvement to the extent permitted by law.”

Iowa's Public Utilities Board (http://www.state.ia.us/iub/) lists the following as its mission and vision:

Mission:

The Iowa Utilities Board regulates utilities to ensure that reasonably priced, reliable, and safe utility services are available to all Iowans, supporting economic growth and opportunity.

Vision:

The Iowa Utilities Board will continue to be a nationally recognized leader in utilities regulation to assure:

- Consumers receive the best value in utility services.
- Utilities receive an opportunity to earn a fair return on their investment in regulated services.
- Services are provided in a safe, reliable, and environmentally conscious manner.
- Economic growth is supported by ensuring utility services adequate to meet new customer demand.
- Consumers have access to the information they need to make informed choices about their utility services.
- Competitive markets develop where effective.

Louisiana Public Service Commission (http://www.lpsc.org/) states, "The overall goals of the Commission are to ensure a regulatory balance that enables utilities to provide customers with safe, adequate and reliable service, at rates that are just and reasonable, equitable and economically efficient, and that allow utilities an opportunity to earn a fair rate of return on their investment. In addition, the Commission continues to take an active and cautious role in development of a competitive, market-based approach to utility regulation whenever such an approach is in the public interest."

As is evident from this very brief review of the stated focus of the different agencies, the importance of competition varies greatly, depending on the agency involved. FERC lists the encouragement of competition as one of its top priorities. In some states, the regulatory agencies place competition at the top of the priority list. In many states, however, if competition is mentioned at all, it is well down on the list of priorities. The lack of a consistent focus on the importance of competition in the electric utility industry contributes to the lack of effective regulation when utilities attempt to purchase merchant facilities.

Economic Theories

Before delving into a review of the proposed regulatory practices that are the focus of this study, it is useful to examine basic economic theories that are applied to the analysis of utility markets. Examination of these theories provides the basis for understanding not only the structure of the electric power industry and the behavior of firms within the industry, but also current regulatory practices, and this study's proposed modifications to those practices. In many decisions, FERC has addressed economic theories that apply to utility markets, most recently in its order modifying generation market power analysis (FERC 2004a).

There are several categories into which studied markets can be classified. The most common are pure monopoly, perfect competition and oligopoly. A pure monopoly exists when only one firm in a market supplies a particular good or service. Under a pure unregulated monopoly, the monopolistic firm's profits are maximized by setting as high a price as possible that will not significantly affect consumer demand or bring competition into the market (George 1992). In all but a very few states, a utility's retail market is a pure monopoly, albeit regulated by the appropriate state commission (Durham & Durham 1999).

Perfect competition exists when there are a multitude of firms that offer homogenous products or services, and each firm acts strategically in order to obtain market share from other firms. There is no dominance by a single firm, or a group of firms, and there are no significant barriers to entry. In a purely competitive market, pricing rapidly approaches the marginal price, where firms will offer services to consumers at an amount only slightly above a firm’s variable cost for producing the product or service (Hanssens 2001).

An oligopoly exists in the region between a pure monopoly and perfect competition. An oligopolistic market exists when only a few firms offer a homogeneous product or service in a particular geographic area. The limited number of competitive firms in a market is most often the result of high barriers to entry. These barriers may take the form of regulation, high startup costs, or strong dominance by a single firm.

A special case of the oligopoly exists when a single firm has a significantly dominant position in the market compared to other firms that participate in the market. The standard measure of dominance is market share, as compared with other firms in the market. There is no fixed market share percentage that defines a dominant firm. It is the relationship between the largest firm’s market share, and the market share of other competitors that determines dominance (George 1992). This is referred to as market concentration.

Concentration in Utility Markets

Regulated monopolistic utilities operate in a monopoly market structure with regards to retail customers. This monopoly is granted by, and is regulated by, state utility regulatory commissions. In areas where electric power markets have undergone restructuring in favor of competition, the wholesale energy markets operate in nearly perfect, although somewhat regulated, competition. In these areas, such as New York and New England, competitive generation entities bid into a day ahead and/or an hour ahead market and those with the lowest price are accepted into the market.

Most utility wholesale markets, however, operate in-between a monopoly and perfect competition. A good measure of this is the market concentration in the wholesale generation market, as measured by the HHI index. It is very common, if not undisputed, that HHI values for wholesale energy markets in areas where the electricity market has not undergone restructuring well exceed the 1800 HHI threshold for highly concentrated markets, as defined in FERC Order 592 (FERC 1996c).

As an example, the OG&E wholesale energy market, as defined in the case study, had HHI values in the post-transaction condition well in excess of 5,000 for many periods. OG&E’s market share, depending on the season examined, was between 55% and 85%. Table 1 shows the values of HHI, in a post-transaction market, of the OG&E control area wholesale energy market. A complete set of tables showing the market participants, associated market shares and HHI calculations for the OG&E wholesale energy market is included in Appendix A.

Table 1 - OG&E Market Share and HHI Values by Season

SEASON EXAMINED	OG&E MARKET SHARE	POST-TRANSACTION HHI VALUES
Summer Super Peak 1	75.5%	5,770
Summer Super Peak 2	74.7%	5,643
Summer Peak	70.0%	4,999
Summer Off Peak	66.6%	4,554
Winter Super Peak	60.5%	3,932
Winter Peak	56.7%	3,549
Shoulder Super Peak	57.4%	3,601
Shoulder Peak	52.8%	3,144

A summer season is defined as the months of June, July and August. A winter season is defined as the months of December, January and February. A shoulder season is defined as the months of March, April, May, September, October or November. A peak period is where demand, and prices are high, where as an off-peak period is where demand is low. At high load levels, prices are quite elastic. This leads to super-peak periods that occur for only a very short time in a season, but which have very high price swings.

Based on the above market discussion, it is most appropriate to concentrate the analysis of economic theories to those economic models that demonstrate market behavior in highly concentrated and oligopolistic markets.

There are many economic models that attempt to describe the behavior of firms in an oligopolistic market. Each of these models has relevance in a particular set of circumstances. The three most historically prevalent oligopoly models are the Cournot, Bertrand and Stackelberg models. There is no need to discuss these models in significant mathematical detail because there is substantial literature available in the public domain that does just that (George 1992, Hanssens 2001). Instead, the basic premises and resulting aspects of firm performance that are inherent in each model are discussed. The model's relevance to the study case is then discussed.

In addition to the three models mentioned above, there is a substantial amount of academic literature that addresses the special case of a dominant firm in an oligopolistic marketplace. This analysis is described as a Dominant Firm - Competitive Fringe analysis. In many, if not all, utility wholesale energy markets, the utility meets even the loosest criteria of a dominant firm; therefore, this analysis will be discussed as well.

Cournot Model

The Cournot model is based on the work of Augustin Cournot, originally published in 1838 (George 1992). In this work, Cournot establishes the mathematical reactions of a profit-maximizing producer, operating in a duopoly (a special case of an oligopoly where there are only two firms) who attempts to maximize profits by changing the quantity of products produced and offered to the marketplace. Models of this type are commonly referred to as fixed-output models (Hanssen 2001). Several basic premises are necessary for Cournot behavior to dominate a market (George 1992, Hanssens 2001):

- Products offered by competing firms are homogenous.
- Firms compete with each other by choosing output level of their products, rather than price. (This assumes that the market size is determined by the output level choices of the supplying firms, rather than the consumer).
- Firms have complete information about their rivals.
- Firms make production level decisions simultaneously.

- Firms treat competitor’s production level decisions as being fixed.
- New entry is severely limited.

In markets where the above assumptions are met, and Cournot behavior dominates, rivals can be expected to perform according to several behaviors:

- Market participants have, and will exercise, market power; therefore, pricing equilibrium is greater than each firm’s marginal cost.
- The degree of market power possessed by each firm is constrained by the elasticity of demand.
- Pricing will be less than monopoly pricing, because market share of each firm is less than 100%.
- As the number of firms increase, market power (and concentration) decreases.
- There is a positive relationship between market concentration and pricing.

In the typical utility wholesale energy market, most of the tenets of the Cournot model are met. Energy products offered by generators are homogeneous, firms have nearly complete information about their rivals, information such as approximate heat rate, fuel costs, etc. adhere to industry averages, and new entry is significantly limited due to the high capital costs of new generation facilities, the transmission constraints, and the market dominance by a single firm. There is no clear evidence, however, that firms compete by choosing the output level of the facilities and by accepting the market clearing price.

There are electric energy suppliers, such as hydroelectric and nuclear generators, that tend to follow Cournot behavior. These facilities have very low, essentially zero, marginal costs due to the extremely low cost of fuel for generation. Thus, it is feasible, if not likely, that these generators would choose to compete by fixing output, and taking whatever price clears the market.

In most utility markets, however, generation supply is dominated by fossil fuel fired facilities (coal and natural gas). Hydro and nuclear generation is a minimal part of the potential supply. Merchant plant competitors to utilities have primarily natural gas fired facilities, which are subject to the high volatility, and relatively high price (as compared to coal) of the natural gas market. Thus, generators are likely to set a minimum price they will accept, and if that price is not met, the generator will not produce. These generators would be competing on price, rather than output as the Cournot model demands. It appears, then, that the Cournot model is not an appropriate representation of the typical utility market.

Bertrand Model

Joseph Bertrand found that the requirement of fixed-output derived in the Cournot model was an inaccurate representation of the marketplace in general, as discussed above. Bertrand argued that firms compete on price, rather than on output (Hanssens 2001). Accordingly, the Bertrand model of oligopoly behavior makes some modifications to the Cournot model. The primary difference between the two is that the Bertrand model assumes that firms compete on price, rather than in making production decisions. Key tenets of the Bertrand model are as follows (Hanssens 2001):

- Market demand is relatively fixed.
- Products offered by competing firms are homogenous.
- Firms compete with each other by choosing price and varying output level with share of market demand.
- Firms make pricing decisions simultaneously.
- Firms treat competitors' pricing decisions as being fixed.

- There are no capacity constraints on production by competing firms.
- New entry is severely limited.

Bertrand behavior is dominated by the following characteristics (Hanssens 2001):

- Pricing of each firm is equal to marginal costs.
- Assuming similar marginal costs for each entity, firms have no market power. The equilibrium price is equal to the firms' marginal cost. Firms with similar costs, therefore, operate at zero profit (perfect competition).
- If firms have differing marginal costs, the firm with the highest marginal cost has no market share.

The results of the Bertrand Model are commonly described as the "Bertrand Paradox". Taken to the extreme, the Bertrand Model predicts that only two firms are necessary to create perfect competition in a market (Hanssens 2001). This is counterintuitive, but supported by the mathematics of the model, given the assumptions above.

There are several aspects to the Bertrand Model that are applicable to a typical utility control area wholesale market. Products offered are homogeneous, firms tend to compete on price, and new entry is severely limited. The problem, however, is the assumption that there are no capacity constraints on production. Because of the high capital costs of new facilities, firms are constrained in production to the full capacity of their facilities, or by the limits in the transmission facilities that keep them from delivering energy to the market.

In the case of limited capacity, behavior is not accurately represented by the Bertrand Cycle. In this case, each firm takes turns marginally undercutting other firms, until one participant finds that it will maximize profits by increasing prices in order to exploit monopolistic pricing on that portion of the market that the other firms cannot serve.

Additionally, although demand for electricity is somewhat price inelastic, it is affected by pricing levels and thus is not fixed. The Bertrand Model, then, does not accurately represent a typical utility market.

Stackelberg Model

Heinrich von Stackelberg modified the standard pricing models described above. Stackelberg argued that, if firms in an oligopoly recognize that profits depend on actions of the other firms, then a different solution is expected (George 1992). The Stackelberg model develops the concept of a leader-follower dominated marketplace.

A follower acts as if rivals will maintain production at stable levels, consistent with the Cournot model. The follower will then adjust its output to maximize profits. A leader will act as if other firms are followers, and will adjust price and output to maximize its profit (George 1992). The key assumptions of the Stackelberg model of oligopolistic markets are listed below:

- Products offered by competing firms are homogenous.
- The dominant firm determines the likely response of competitors, and sets output to maximize profits (Leader).
- The fringe firms take the output of the dominant firm as a given and sets pricing to maximize profits (Followers).
- Output and pricing decisions are made sequentially, leader first and then followers.
- Capacity is constrained.
- Market demand is inversely proportional to pricing.
- New entry is severely limited.

The results of the Stackelberg model predict that the following results will be obtained in an oligopolistic market that meets the above assumptions:

- Profit of the leader is higher than Cournot results, but less than monopoly.
- Profit of the followers is lower than Cournot results, but higher than perfect competition.
- Pricing equilibrium is above marginal costs.
- As number of followers increase, pricing approaches marginal cost (perfect competition).

Of the three historical oligopoly models described, the Stackelberg model most closely represents the typical utility market. All of the assumptions of the Stackelberg model appear to be supported by the actions of the competitors in utility markets. Products are homogenous. A utility's affiliated generation, acting as the leader firm, responds to the market by supplying an amount of generation that will maximize its profits (including supplying the utility as the load serving entity (LSE) to retail and wholesale load). Other firms then respond to the amount of residual demand and compete with each other on price.

Capacity of both the leader and the follower firms is limited by the physical characteristics of their facilities. New entry is limited by the factors described in the discussion of the Cournot model.

Finally, even though there is a certain amount of price inelasticity in the demand for electricity, as prices increase there is additional emphasis placed on reducing consumption of energy in the residential, commercial, and industrial sectors. As wholesale customers' demand follows retail demand, a reduction in retail demand will result in a reduction in demand for wholesale energy. Thus, the wholesale market is price sensitive.

Dominant Firm – Competitive Fringe Analysis

For the special case of a dominant firm in an oligopolistic market, examination of the dominant firm-competitive fringe analysis will be beneficial to this study. The existence of a dominant firm in many, if not all, regulated monopolistic utility markets was discussed previously. The example of the OG&E wholesale market clearly demonstrates that this market exhibits a dominant relationship between the utility and its rivals. Assuming that utilities which attempt to purchase a rival merchant generating plant enjoy a dominant position in the wholesale energy market, there are several potential behaviors with which the dominant firm can attempt to maximize its own profits.

Kenneth George, in his book on industrial organization, gives a comprehensive description of anticipated behaviors of a dominant firm (George 1992). The following behaviors assume several characteristics of the market:

- Products offered by competitors are homogeneous.
- There are no significant barriers to entry, other than the pricing structure of the dominant firm (No regulatory restrictions, etc.).
- Market demand is elastic.
- There are no regulatory restrictions on behavior of the dominant firm.

Several particular behavioral options are discussed.

Short Term Profit Maximization

The dominant firm could act in a way to maximize short term profits, at the potential risk of losing long-term market share. A firm exhibiting this behavior would set prices at or near monopolistic price levels. The dominant firm would react passively to any changes in production or pricing structure by the competitive fringe. As prices set by the dominant firm are well in excess of the marginal cost of production for the product(s) offered, there is a significant incentive for competitive firms to either expand capacity or enter the market. Thus, in the long term, market share would shift from the dominant firm to its rivals, and the firm's dominant position would be eroded. (George 1992)

Pricing to deter entry

As opposed to reacting passively to the actions of the competitive fringe, the dominant firm could, instead, choose to act aggressively in its pricing behavior to discourage entry or expansion by rivals. In order to exercise this behavior, the dominant firm is assumed to have a cost advantage over its competitors, and is assumed to have near 100% of the market (George 1992).

To exercise this pricing behavior, the dominant firm sets its prices just below the marginal production cost of the rival firms. This allows the dominant firm to make a profit over its marginal cost, but does not allow competitive firms to meet marginal costs (George 1992). Entry or expansion by competing firms is thus strongly discouraged. Unlike the short-term behavior described above, the dominant firm's market share is not eroded over time. In fact, the market share of the dominant firm can be expected to increase until it gains 100% of the market volume.

Price Predation

A dominant firm may expand profits further by exercising a predatory pricing policy. This behavior is an expansion beyond the pricing to deter entry described above. The assumption that the dominant firm has marginal costs below that of rival firms is relaxed. In order to exhibit predatory pricing behavior, the dominant firm cuts the prices of its product below the marginal cost of the competitors, whether or not this price is below the marginal cost of production for the dominant firm.

Due to the fact that the rival firms cannot make a profit, they are likely to exit the market. Even if the dominant firm is not making a profit, it is assumed that, because of its size, it can survive longer than rival firms due to larger cash reserves or a better credit position (George 1992).

Once competitors have exited the market, the dominant firm then raises prices to near monopoly levels in order to make up for lost profits. To the extent that the profits recovered during the period of high prices exceed the profits lost during the period of low, or negative, profits, then the predatory pricing strategy is effective.

In the case where the dominant firm does have a cost advantage over its competitors, due to its size or position on the learning curve, then the dominant firm will not have negative profits during the period of low pricing. The dominant firm, then, has additional incentive to engage in predatory pricing (George 1992).

Discriminatory Pricing

Another pricing strategy that the dominant firm can use is to discriminate between customers when setting prices. If the dominant firm can successfully separate classes of purchasers, such as wholesale purchasers of energy vs. retail purchasers of energy, then the dominant firm can engage in predatory pricing in one segment of the market in order to discourage competition, and subsidize this effort by using profits from another segment of the market (George 1992).

This behavior is particularly likely when, as in the case of regulated monopolistic utilities, the dominant firm competes in both protected (regulated) markets and competitive markets. In the case of utilities, the retail market is protected under state regulation, while the wholesale energy market is being driven to a more competitive state by FERC regulations. When uncontrolled, this opens opportunity for undue price discrimination.

Non-Pricing Strategies

Firms that have a strong dominant position can engage in strategies other than setting pricing structures in an effort to maximize profit at the expense of competition. There are two of these actions that apply to the situation under study. These are vertical restraints and acquisition of excess capacity.

The first of these is vertical restraints, or the exercise of vertical market power as discussed in a previous section (George 1992). This type of market manipulation is available when the dominant firm controls inputs to production or channels of distribution for the competing products. Such is the case when the utility owns both competing generation and the transmission system necessary for delivery of electric energy to consumers.

The second type of non-pricing activity that a dominant firm can engage in is to build or acquire excess production capacity, above what is needed to meet its customer obligations. If a dominant firm has excess capacity, then it can react more robustly to entry or to other actions that rival firms can take (George 1992). When the excess capacity can be funded by a protected segment of the market, such as a utility's retail customers, but used in a competitive market, such as wholesale energy, then the effects of this excess capacity are highly anti-competitive (FERC 2003c).

Comparison of Economic Models

It appears that the Stackelberg assumptions and the analysis of Dominant Firm / Competitive Fringe most closely represent the electricity market in utility wholesale markets. FERC, in its order regarding analysis of generation market power, recognizes this. When discussing analysis of wholesale market share, the Commission mentions both the Stackelberg model and the Dominant Firm / Competitive Fringe analysis as methods that represent utility markets and support HHI analysis of the effects (FERC 2004a).

The expected results of these models, as they apply to market concentration, are now examined. The most relevant of these results is that as the number of followers or rivals (competitors) increases, pricing approaches marginal cost (pricing decreases). As more competitors enter the market, it is expected that concentration of market share among competitors will be reduced. Thus, decreases in HHI would be expected to reduce wholesale prices, and, conversely, an increase in HHI would be expected to increase wholesale pricing.

It is important, then, that the results of HHI for both the proposed acquisition, and all potential mitigation efforts, be examined to determine what the expected effects on pricing will be. The Revised Merger Guidelines recognize this importance by requiring that an HHI analysis be conducted to show the effects of all structural mitigation efforts (FERC 2000c).

Deficiencies of Existing Guidelines

The existing FERC guidelines, outlined in Order Nos. 592 and 642 were created to deal with utility mergers; that is, the combination of utilities that have previously operated in different control areas. These guidelines have been used successfully in a number of merger cases to appropriately mitigate the effect on market power that these mergers create. The guidelines, however, are deficient in their treatment of utilities acquiring rival generating stations that are operating in the utility's control area. Specifically, the policies are deficient in three key areas:

1. The existing policies do not adequately address the increase and exercise of vertical market power by the utility.
2. The existing policies are based on flawed economic models and do not adequately mitigate effects on market concentration.
3. The existing policies do not address the long-term impacts of the acquisition.

Deficiencies in Dealing with Vertical Market Power

The existing merger guidelines, as discussed above, do not give emphasis to impacts on vertical market power. In the large majority of the cases, the selection of vertical markets to be examined is left to the applicants (FERC 2000c). While this is not an effective way to deal with any transaction, it is especially harmful when examining the impacts on the market created by an acquisition of a merchant plant by the local utility.

In this case, the utility has complete control over the delivery system of competitive generating plants through its control of the transmission system. Thus, the utility has the ability to completely foreclose its rivals from delivery to the market (Hogan 2002). Once the utility purchases a competitive generating plant, the ability to foreclose has been increased, due to the fact that the utility is using additional transmission facilities to transport power from the new facility to its destination. The utility also has increased incentive to foreclose, due to the fact that it has additional generation that would benefit from any pricing above competitive levels.

Transmission expansion, the standby of the FERC regulations, has the potential to mitigate the increase in *ability* of the utility to foreclose competitors through its control of the transmission system by increasing the amount of transmission that is available. It does not, however, address the increase in *incentive* that the utility gains through the acquisition.

Deficiencies in Dealing with Increased Market Concentration

Contrary to the increased emphasis that FERC has placed on competition, the analysis on economic theories in the previous sections, and the reference to Stackelberg and Dominant Firm / Competitive Fringe analysis in FERC 2004, the FERC staff and Commissioners appear to rely on the theories of the Bertrand model in order to support their proposed mitigation efforts.

In practice, the FERC staff, in a number of cases, including the OG&E-McClain proceeding discussed in this study, contends that HHI analysis of mitigation efforts is irrelevant. Both in mergers and in the unique case of a utility acquiring a rival merchant generator, the primary mitigation effort imposed by the Commission is expansion in the transmission system to allow new entry (or expanded entry) by competitors. The amount of transmission expansion required merely equals the amount of generation that was removed from the market by the proposed acquisition. No effort is made to reduce market concentration to levels that would pass the FERC, DOJ or FTC competitive screen analysis.

For example, in the OG&E-McClain case, OG&E acquired 400 MW of generation from the McClain facility. This 400 MW of generation was removed, then, as a competitor to OG&E in the wholesale energy market. The Commission contends, and so ordered, that, if 400 MW of new supply was allowed to compete in the market, then wholesale customers are not disadvantaged by the acquisition, and any anti-competitive effects of the transaction have been mitigated. What has not been mitigated, however, are the increases in the utility's market share, or the utility's increased excess supply that allow it to more easily act as a leader, or as a dominant firm.

Though not explicitly stated, there are several characteristics of the FERC analysis that indicate the Commission's reliance on the Bertrand representation of the market. A few are discussed below.

FERC's contention that replacing acquired supply offsets the anticompetitive effects inherently relies on a single competitor to completely offset the increases in market power. FERC's statements in its June 2, 2004 order approving the OG&E-McClain transaction fully support this. In this order, the Commission relied on transmission expansion designed to allow a single competitor into the market to discipline OG&E's pricing structure (FERC 2004b). Additionally, FERC states that "offsetting of the 400MW supply by access to an equivalent alternative supply will address the concerns raised by the horizontal screen failures" (FERC 2004b). Only the flawed Bertrand model states that only two competitors result in perfect competition.

This offsetting of supply has long been the commission's position when dealing with mergers of utilities operating in separate control areas. It does not, however, address the increases in market power and the anti-competitive effects of a highly dominant utility's acquisition of a direct rival. The increases in market power in such a tight environment have much more deleterious effects on competition than do increases in market power in broader environments, such as one would expect when utilities merge.

In contrast to FERC practice, the behavior of generators and market conditions more closely follow the Stackelberg model. The Stackelberg model shows a positive relationship between concentration and anticompetitive effects (such as increased pricing, and non-pricing activities intended to squash competition). The analysis of Dominant Firm – Competitive Fringe also shows a positive relationship between concentration and anticompetitive effects.

The Merger Guidelines and Order 642 rely on the premise that increased concentration, as measured by HHI, increases the anticompetitive effects of the transaction (FERC 1996c, FERC 2000c).

There is an even stronger effect when applied to a highly concentrated market such as the OG&E control area. Thus, in order to ensure that a proposed transaction does not harm competition, it is important to examine the effects of mitigation on HHI. Reductions of HHI increases to levels that pass the competitive analysis screen are required to offset the impacts from market concentration.

Deficiencies in Dealing with Long-Term Market Impacts

There is an additional incentive for a utility to foreclose a competitor by exercising either its buyer market power or its transmission and generation market power. When a generation competitor, located in the utility's control area, is successfully foreclosed from the market for an extended period of time, that competitor is eventually forced to divest those resources that, theoretically, were competitive with the utility. As other independent generating companies recognize the inherent problems of trying to operate a plant in that utility's control area, there will often be only one potential purchaser of the generating assets: the utility itself. These purchases are most often made at a fraction of the competitor's actual construction costs, and for a fraction of what the utility could build an equivalent facility for itself. This gives the utility an additional edge when competing in the wholesale market.

If purchase of a competitor's generating assets is allowed to proceed without proper mitigation, the utility has increased ability and incentive to keep foreclosing competitors and eventually control essentially all of the "competitive" generation in the market. This becomes a significantly more serious issue once markets have transitioned to full competition. With one entity controlling all of the supply in the market, it would be difficult for any competitor to enter the market and compete. In order to mitigate this situation, forced divestiture of the utility's generating assets will be required. This creates significant regulatory problems (US DOE 1998).

. Proper mitigation must take the long-term effects of the purchase into account and create disincentives for the utility to use the purchased generation as a way to increase their foreclosure of competitors. If proper mitigation is not applied, the transition to fully competitive markets in the utility's control area will be substantially more difficult.

Additionally, the addition of new fixed assets, such as a generating facility, further exacerbates the situation of stranded cost recovery in a future, competitive environment. Stranded costs are those costs incurred by a utility, for which they have been granted a return over the course of several years. If a competitive marketplace is imposed before this term is up, there are costs that the utility has yet to recover. These must be dealt with in some way. With the acquisition of fixed assets, these un-recovered costs increase. Since the expenses of stranded cost recovery are borne by the market in general, this must be a factor in determining the effects of such an acquisition on the market. If, instead, utilities gain supply for service of their load from the marketplace, as is proposed, stranded cost issues are minimized.

Proposed Modifications to Regulatory Practices

As discussed earlier, state commissions are primarily interested in ensuring that acquisitions by utilities are "prudent", while FERC is charged with protecting competition. A prudent investment, based on the published goals of state regulators, is one that is favorable to the utility investors and the rate payers. A prudent investment also encourages, rather than discourages, the development of competition, including insuring adequate alternative suppliers.

For such purchases to go forward there must be close scrutiny of proposed purchases of direct competitors in a control area by the vertically integrated utility. To the extent that these purchases result in increased market share by the dominant provider, adequate mitigation of such increases must be implemented. A simple 1 for 1 replacement of generation by transmission expansion does not adequately mitigate the increased market power.

These types of purchases are substantially different from the mergers and acquisitions that the Commission addressed in prior Section 203 proceedings. In a vertically integrated utility's control area, the utility has both transmission market power and generation market power, based on the Commission's order on Generation Market Power Analysis (FERC 2004a). The purchase of a competitor's generation assets increases the utility's market power for both transmission and generation, first by removing the generation from the market (generation market power), and by increasing the utility's use of the transmission system by the amount of purchased generation (transmission market power). When the purchased generation asset was previously a competitor located in the utility's control area, the increases in generation and transmission market power can be, and in most cases are, enormous. Mitigation must address the increases in both transmission and generation market power.

There are other areas related to competitive practices that must be addressed when examining such acquisitions. The utility, acting as the load serving entity, has an incentive and the ability to purchase wholesale power from its own generating assets, to the exclusion of other potentially competitive suppliers. Often these generation suppliers offer energy at a much lower cost than the utility, as a generation company, can produce. Yet, this efficient generation capacity is often foreclosed from the market by the utility's exercise of its buyer market power; therefore, purchase of a direct competitor in the utility's control area increases both the ability and the incentive to purchase from its affiliated generation assets to the exclusion of more cost effective competitive generation suppliers.

Additionally, the utility has an incentive and ability to foreclose competitors from the market by control of its transmission system, and by strategic dispatch of its affiliated generating units. This is an exercise of both transmission and generation market power working in concert that is unique to a vertically integrated utility operating in its control area. Purchase of a direct competitor in the utility's control area increases the amount of affiliated generation that the utility can use to foreclose competitors, and uses additional transmission capacity that is no longer available to competitors. The utility can, additionally, dispatch its transmission system in such a way that the competitor is left without adequate transmission capacity.

There are four specific mitigation efforts that are proposed in order to deal with the increases in horizontal (generation) and vertical (transmission) market power that result from these type of transactions. All the mitigation alternatives are some component of a market driven solution, but do not impose retail choice, an issue best left to state direction.

1. The transactions must be examined from a stronger, long-term market-based analysis. The utility's increased ability and incentive to foreclose competitors from the market must be addressed. At a minimum, if a utility proposes potential new entry to combat increased market concentration, this potential new entry must be sufficient to bring the market concentration back to a point where it would pass the Commission's Competitive Screen Analysis (HHI increases below 100 for highly concentrated markets).
2. While potential new entry, in the form of transmission expansion, addresses increases in the utility's transmission market power, it does not effectively address the increases in generation market power. In the absence of an ISO or RTO, this potentially competitive generation has no ability to penetrate the market in any meaningful way. In order to address the increases in generation market power, and to prevent the utility from using its new generation purchases to further foreclose competitors from the market, opportunity must be given to competitors to actually deliver competitive generation into the market. At a

minimum, competitors need to be allowed to compete on a wholesale basis directly with the affiliated generation to deliver the amount of generation that was called out as potential new entry through transmission expansion. This will effectively address the utility's increased ability and incentive to benefit from its dominant position during times of high peak load, when supply margins are small and monopoly prices would be high. Without, at least, the option of these competitors becoming actual suppliers, the utility's wholesale pricing decisions have no discipline.

3. In the absence of an RTO, the utility's operation of the transmission system must be effectively monitored in order to prevent foreclosure of competitive generator's access to the transmission system, including exercise of its increased buyer market power. An effective market monitor will not only address transmission issues (such as calculation of ATC, TTC, posting on OASIS, etc.), but will also oversee the implementation of mitigation of generation market power.
4. In order to ensure that competitive wholesale supply is balanced with the interests of the retail consumer, the process of allowing potential suppliers access to become actual suppliers most

often should be implemented under the direction of the state utility commission. This commission is already tasked with overseeing the utility's acquisition of generation, and is in the best position to direct this process.

5. As an alternative, the Commission could order a 1 to 1 divestiture of generation by the utility. This will eliminate the short term market power issues, as well as reduce future problems, such as potential stranded cost recovery and the utility's increased incentive and ability to exercise both transmission and generation market power.

The implementation of these recommendations will not only address the immediate competitive concerns generated by a purchase of rival generation by the utility, but will also leave the market essentially unchanged in light of future industry restructuring.

Each of the recommendations will be described in more detail, with reference to the case study, below.

Step 1 – Reduction in HHI Values to Pass Competitive Screen

The first step in the modified procedures involves acquisitions where market expansion, through upgrades to the transmission system, is employed in order to address increases in concentration. Under current practices, market expansion must only be undertaken to the point that the expansion matches the amount of competitive generation that has been removed from the market. Under the modified practices, however, transmission expansion must be undertaken to the point that the market concentration, as measured by HHI values, would pass the competitive screen.

A more detailed explanation of the specifics necessary to implement this step is included in Chapter 4.

Step 2 – Make Potential Competitors Actually Competitive

The second step in the modified regulatory procedures is to ensure that *potential* competition identified in Step 1 is actually allowed to compete in the marketplace. The HHI analysis, by its nature, assumes that there is some level of competitive marketplace in the destination market. The competitive generation, then, could take advantage of the transmission upgrades in order to actually expand the market, and create a disciplining effect on pricing by the dominant utility.

In actuality, however, in the study scenario, the utility is not only the dominant supplier into the market, it is also the dominant purchaser from the market. Unless the utility purchases power from competitors using the transmission upgrades the mitigation efforts have no real effect.

While Step 1 goes to eliminating the increased *ability* of the utility to use its increased market share to disadvantage competition, step 2 goes to eliminating the increased *incentive* of the utility to do so. Should the utility undertake to foreclose a specific competitor by using its dispatching of its generation assets in an uneconomic matter, another competitor would be able to enter the market and compete with the utility. Thus, there would be little incentive for the utility to act in an anti-competitive manner.

The purpose of this step is not to force competition on the utility markets and address the existing anti-competitive marketplace, but to offset the increases in the monopolistic nature of the market as a result of the acquisition (FERC 2003c). As a result, all purchases by the utility need not be open to competition from these potential competitors.

Only the generation necessary to expand the marketplace, in this case 815 MW, would be required to be opened to competition. In practice, the utility would be forced to accept bids from generators for supply of generation capacity and energy. These prices would be compared to purchases made by the utility, as the load serving entity, from its affiliated generation. To the extent that the third-party bids are less-expensive than the purchases from the affiliated generation, the utility would enter into purchase contracts with the competitive generation, up to a maximum of 815 MW.

As a result, the potential competitive increases identified in Step 1 would have a chance of actually competing in the destination market. This would provide a disciplining effect on the costs of wholesale generation from all suppliers, especially the dominant utility. Additionally, only the anti-competitive increases in market concentration would have been addressed, leaving the destination market in essentially the same condition as prior to the acquisition.

Step 3 – Market Monitor

The application of step 4 of the modified regulatory procedures is to implement a market monitor, as called out in FERC order 2000 and Order 2000-A (FERC 1999, FERC 2000a). FERC has recognized that, in the standard utility market, there is a need for a market monitor to oversee the actions of utilities and to ensure that the utility does not use its control over the transmission system to foreclose competitive generation from the marketplace. The need for this monitoring function is even more necessary in the study scenario.

Should a market monitor be absent, the utility could operate its transmission assets in such a way as to prevent a low-priced competitor from having physical access to the transmission system. Without this physical access, the competitor has no method of being an actual competitor, and can have no disciplining effect on the dominant firm's pricing.

Additionally, there needs to be a body that would be in charge of overseeing the competitive supply bids, as described in step 2 of the modified regulatory procedures. The market monitor would provide the transparency of bids and analysis that is necessary for a competitive market, even a limited one such as described above, to operate.

The market monitor would be charged with three basic functions.

- Ensure that the utility's operation of the transmission system is based on good utility practice and the transmission system is not being used to prevent a potential competitor from having access to the market.
- Oversee the bid process to ensure that the utility is making appropriate decisions regarding purchase of competitive generation.
- Oversee the actual purchases of generation energy to ensure that the utility is adhering to the purchases required by the bid process.

Since the implementation of an RTO that encompasses the utility's control area inherently contains provisions to prevent discriminatory operation of the transmission system, the first function of the market monitor could be eliminated, should the utility fully join an RTO.

Step 4 – Process Overseen by State Regulators

A regulatory body must have authority to oversee the functions of the utility as it regards the competitive generation and market monitor practices. The state regulatory commission already has the responsibility of overseeing utility generation purchases, as part of the prudency review of utility actions. This commission, therefore, is in the best position to balance the needs of the competitive marketplace, with protection of the interests of existing ratepayers.

FERC has the authority to refer any matter that affects states to a board of members from each of the states that are affected. FERC can also invest all of its power to deal with the matters under review to this board of states (US Congress 1977). FERC, then, has the authority to invest its power to oversee implementation of these regulations to the state commission, or a board of state commissions, should the utility operate in multiple states.

The implementation of the bid process for the 815 MW of generation, along with selection and implementation of the market monitor functions would be under the purview of the appropriate state regulatory commissions or boards. Funding for these activities could be provided by collecting a very small percentage of the energy sales that are made under the competitive bid plan.

Step 5 – Alternative – Divestiture of Existing Generation Assets

Ultimately, the anti-competitive results of the transaction are determined by the reduction in generating assets that compete with the utility, along with an increase in the amount of generation that is controlled by the utility. In the study case, OG&E has obtained an additional 400 MW of generation, while the amount of competitive generation has been reduced by 400 MW.

Should the utility divest a portion of its existing generation assets that equal the amount of assets purchased as a result of the transaction, then the market would be left in an identical condition to what it was prior to the acquisition. Specifically, if OG&E were to divest 400 MW of existing generation, and this generation was purchased by a competitor, then the level of OG&E controlled generation, and the level of competitive supply, would be equal to the pre-transaction scenario.

The utility would be allowed to divest generation that is old, inefficient, or in other ways undesirable to the utility. This would allow a benefit to the ratepayers from the divestiture, as the ratepayers would not be required to support this old generation.

An analysis of the OG&E generation yields a prospective list of generators that could be divested by OG&E, without placing undue burden on OG&E. These generators are shown in Table 2. This list represents the least efficient generation assets that are currently owned by OG&E. The total of the list is 446 MW, 11 percent in excess of the 400 MW purchase. The utility, in this case OG&E, should be able to modify the list as they see fit, as long as total divestiture exceeds 400 MW.

Table 2 - OG&E Divestiture Options

FACILITY	NAMEPLATE	HEAT RATE
Enid 1	15	18,500
Enid 2	15	18,500
Enid 3	15	18,500
Enid 4	15	18,500
Mustang 5A	42	18,500
Mustang 5B	42	18,500
Seminole GT1	24	18,500
Mustang 2	63	12,388
Mustang 1	82	12,157
Mustang 3	133	10,491
Total Divestiture	446	
Mean Heat Rate		16,454

Another interesting fact is shown in Table 2. The mean heat rate of the units selected for divestiture is 16,454 BTU/kWH, which represents an average thermal efficiency of 20.7%. The heat rate of the McClain facility is 7,100 BTU/kWH, which represents a thermal efficiency of 48.1%. Thus, even though the utility has divested a portion of its resources and market share has not changed, the utility is placed in a better competitive position than before the acquisition, since it is now competing with generation that has a higher efficiency.

A second positive result of the divestiture alternative is that it prevents increases in future problems, when the utility market is driven to a competitive marketplace. It is clear from the FERC rules to date that the Commission is intending to drive the market towards competition. With utilities owning larger and larger portions of the generating assets in a marketplace, the move toward eventual competition is harder. With the divestiture option, this situation is not exacerbated by the purchase.

CHAPTER 3 METHODOLOGY

Approach

The approach to the study contained in this document is threefold. Initially, a literature review of regulations, legislation and academic literature was conducted. As the specific topic of study is new, only being applicable to one historic case, the body of academic literature outside the regulatory process was found to be limited. Regulations promulgated by agencies such as FERC, however, are based in no small part upon public discussion and, as such, contain a large amount of the industry and academic body of thought on the topic.

Once the literature review was completed, certain changes to the regulatory process were proposed. These modifications were placed into a five-question survey. The survey questions were based on the five tenets of the proposed changes. Respondents were then asked to indicate their level of support for each of the modifications on a five-point Likert type scale.

Finally, a case study was examined. In order to demonstrate application of the proposed modified regulatory procedures and what affect they would have on the electric energy market, an examination of the proposed procedures on the recently concluded OG&E / McClain generation acquisition was conducted.

Data Gathering Method

Two methods were employed to obtain data for research of the study topic. For the survey portion of the study, the questionnaire was designed to minimize the level of bias in the questions, was distributed to power industry professionals, and the data was analyzed.

For the case study portion of the research, information relative to the case was acquired and synthesized. This involved gathering and reviewing the entire body of testimony and evidence filed in the FERC administrative law proceeding recently conducted on the case. An evaluation of the effects on standard market measures using both the existing criteria, and the modified criteria, was conducted.

Database of Study

The database of study for the case study portion of the research was the entire body of testimony and evidence filed in FERC Docket EC03-131-000, *Application of Oklahoma Gas & Electric, Co. and NRG McClain, LLC for Approval of Disposition of Jurisdictional Resources.*

The population for the survey portion of research was a group of 20 power industry professionals, carefully selected to represent utilities, independent power producers, large industrial consumers, regulators and independent consultants. These individuals were contacted in person, by email or phone, and the survey instrument was provided in person, by email or fax. Respondents could return the completed instrument in any of the three ways mentioned. The survey instrument is provided for reference on the following page.

The Federal Energy Regulatory Commission (FERC) has recently begun examining cases involving a regulated utility purchasing a merchant generating facility located in its control area. FERC has recognized that these transactions can create an anti-competitive environment and efforts must be made to offset this.

To date, FERC has imposed efforts such as transmission expansion to allow competitive generation to have the potential to compete with the utility on wholesale load, and a limited market monitor role. FERC has not attempted to address the increased market concentration that results from these purchases

Please indicate your level of agreement or opposition to the statements below.

Please indicate your affiliation with the power industry.

Utility	IPP	Industrial	Regulator	Academic /Consultant	Other

When a utility proposes expanding the transmission system to encourage *potential* competition, expansion should be large enough to bring market share back to levels near those that existed before the purchase.

Strongly Oppose	Oppose	Neutral	Support	Strongly Support

In order to make the potential competitive generation discussed above *actually* competitive, competitors should be included in a merit order dispatch system with the utility's generation. The most efficient, lower cost, units, regardless of ownership, would be dispatched first.

Strongly Oppose	Oppose	Neutral	Support	Strongly Support

The process of including competitive generation in a merit order dispatch system should be directed and implemented by the state utility commission in order to ensure a balance between competition and retail service.

Strongly Oppose	Oppose	Neutral	Support	Strongly Support

The utility's operation of the transmission system must be effectively monitored in order to prevent the utility from keeping competitors out of the market. An effective market monitor will not only address transmission issues, but will also oversee the implementation of the merit order dispatch system described above.

Strongly Oppose	Oppose	Neutral	Support	Strongly Support

As an alternative to the above four mitigation efforts, the utility could divest old generation units that equal the amount of new generation purchased.

Strongly Oppose	Oppose	Neutral	Support	Strongly Support

As a group, the above efforts effectively address utility market concentration concerns that result from the purchase.

Strongly Oppose	Oppose	Neutral	Support	Strongly Support

Validity of Data

Each of the different types of data presented offer a different insight into the question studied. Both the quantitative data, in the form of responses to the survey instrument described above, and the case study are valid data for this study.

The case study provides a reference point for background information about the study. The case study also provides an opportunity to compare and contrast effects and results of the current regulatory practices and the new, proposed regulatory changes. Finally, the case study provides a real-world example of the usefulness of the study.

The quantitative data demonstrates the current level of acceptance of the proposed regulatory practice modifications. This information can be used to examine the level of support or resistance that may be encountered when attempting to implement the proposed modifications.

Originality and Limitation of Data

The data is original in two ways. First, the proposed modifications to the regulatory practice are the original work of the author. Thus, any discussion of the validity or level of support for these modifications is, by definition, original. Additionally, the survey results were obtained through the use of an original instrument, designed and distributed for the purposes of this study.

There are potential limitations to the research methods that were recognized going into the study. There is an innate risk of the author's bias entering the wording of the questionnaire instrument and skewing the results. This was addressed in three ways. First, the wording of the instrument was carefully reviewed to minimize the level of recognizable bias. Second, distribution of the survey instrument was made to industry professionals who have a higher level of understanding of the topic under study than the general public. Finally, these professionals were carefully selected to represent all segments of the power industry.

Additionally, because of the highly technical nature of the topic, the population of potential respondents was very small, when compared to studies of a more populist nature. Thus, any bias that is introduced by wording of the questionnaire, or bias of the respondents, has a significant impact on the results.

Regarding the case study portion of the research, the primary limitation of the data is that there is only one case, to date, that is applicable to the study topic. Necessarily, then, this is the first case to be litigated on the topic. Thus, the data regarding that case may be misrepresentative of the entire industry, and biased for the particulars of the proceeding. While the anticipated number of these cases in the future is relatively high, leading to the importance of the study, to date the study case is unique.

Summary

The methodology of the study is implemented using a three-pronged approach. Initially, a review of the existing literature lays the groundwork for the proposed regulations. Secondly, the proposed regulations are applied to a case study, which demonstrates the effectiveness of the suggested modifications. Finally, industry professionals provide input regarding the current level of acceptance of the proposed modifications by replying to a survey instrument based on a Likert-type scale. Each of these data methods provides input into the study.

The quantitative data is limited by the restricted number of industry professionals that possess a broad enough understanding of the topic to make a valid analysis. This, coupled with the standard limitations on surveys, provides a check to the quantitative data. The case study data is limited due to the fact that there is, to date, only one case that has arisen that would be applicable to the specifics of the study. The results of the case study, therefore, may be skewed by the specifics of the market in that case study, rather than representing a broad analysis of the market as a whole.

CHAPTER 4 DATA ANALYSIS

Introduction

Results of the research are presented in Chapter 4. This chapter is divided into two sections. The first section deals with the results of the survey process. Responses to the survey questionnaire are presented, along with analysis and correlation of the data. The survey responses show the level of support or opposition that industry professionals, from a broad representation of the power industry, have to the proposed changes to the existing regulatory procedures.

The second section of this chapter addresses the results of the case study. Analysis is provided regarding application of existing regulatory guidelines to the study case. An examination of the different results that would be expected under the proposed modified regulatory practices is then undertaken.

The analysis presented in this chapter support the conclusions, recommendations, and summary that is presented in the final chapter.

Survey Results

Survey questionnaires were prepared and provided to 20 industry professionals with special expertise in the utility power industry. These professionals were chosen based on two criteria: familiarity with issues surrounding utility regulation and area of power industry interest. Due to the relatively small sample size, careful attention was paid to selecting professionals that represent all segments of the power market.

Of the 20 survey questionnaires provided, 16 respondents returned completed surveys. This represents an 80% response rate. For tabulation purposes, Responses to Question 1 were given a numeric value based on their position on the survey questionnaire, with a “1” response indicating a utility, “2” indicating IPP, “3” indicating an industrial consumer, “4” indicating a regulator, and “5” indicating an academic or consultant role. Reponses to questions 2 through 7 were scored on a Likert type scale, with “strongly oppose” receiving a 1 score, and “Strongly Support” receiving a 5 score. The mean and median scores are identified. Table 3 shows a tabulation of each of the survey responses received.

Table 3 - Survey Responses

Response	Quest. 1	Quest. 2	Quest. 3	Quest. 4	Quest. 5	Quest. 6	Quest. 7
1	5	5	5	5	5	5	5
2	3	4	5	4	3	4	4
3	3	4	5	2	5	1	4
4	5	4	4	4	4	2	2
5	4	2	5	2	5	2	4
6	1	2	1	1	2	1	1
7	3	4	4	3	4	1	2
8	1	4	4	4	4	3	3
9	5	4	5	3	4	3	4
10	4	4	4	3	4	4	4
11	3	3	4	4	5	2	3
12	2	5	5	4	5	4	5
13	4	3	5	5	4	2	3
14	1	3	1	3	2	1	2
15	2	5	5	5	5	5	5
16	4	4	4	5	5	1	4

Survey Question 1

The first question of the survey shows the industry segment with which the respondents most closely identified themselves. The histogram shown in Figure 4 shows the responses to this question. Reponses were received from each of the six categories identified in the question. The most responses were received from those respondents in the regulator and industrial consumer categories. Only two respondents that identified themselves most closely with Independent Power Producers (IPPs) provided complete surveys.

Although not completely balanced, responses were received from all areas of the power industry. The results, then, to at least some degree, represent a broad perspective among industry professionals in the power industry.

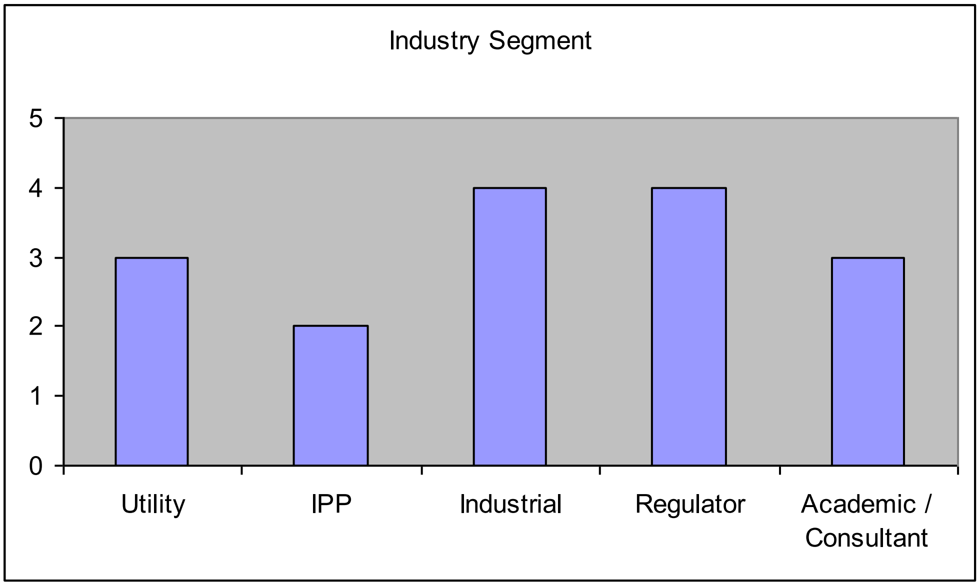

Figure 4 - Survey Question 1 Responses

Survey Question 2

The second survey question asked respondents to indicate their level of support or opposition to bringing market share and, as a result market concentration back to near pre-transaction levels. This is representative of Step 1 of the modified regulatory procedures outlined in Chapter 2. The responses to question 2 show a large level of support, spread across all industry segments.

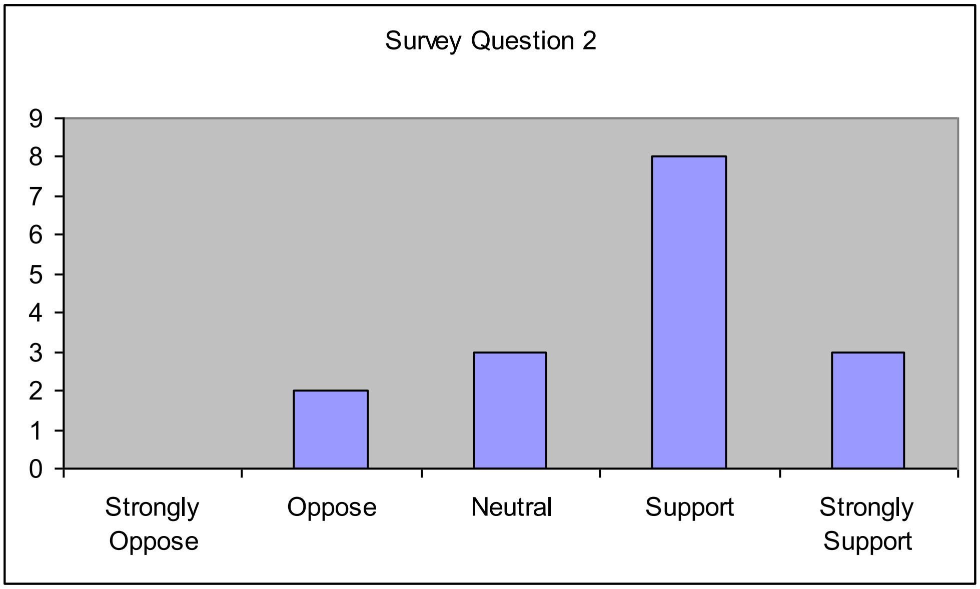

Figure 5 - Survey Question 2 Responses

69% of all respondents indicated support for the proposition. Only 13% of respondents indicated opposition to the proposal, with no respondents indicating strong opposition. The mean Likert value for question 2 is 3.75, with the median response being 4, or indicating support for the proposition. The responses indicate normal distribution around the mean, with a standard deviation of 0.92.

Survey Question 3

The third survey question asked respondents to indicate their level of support or opposition to the concept of a merit order dispatch system, designed to make potential competitors actually competitive. Responses to this question indicate strong support, with outliers indicating strong opposition. 88% of all respondents indicated support for the idea of implementing merit order dispatch in cases such as the study case, with 57% of these respondents indicating strong levels of support. Figure 6 shows a histogram representing the number of responses in each category.

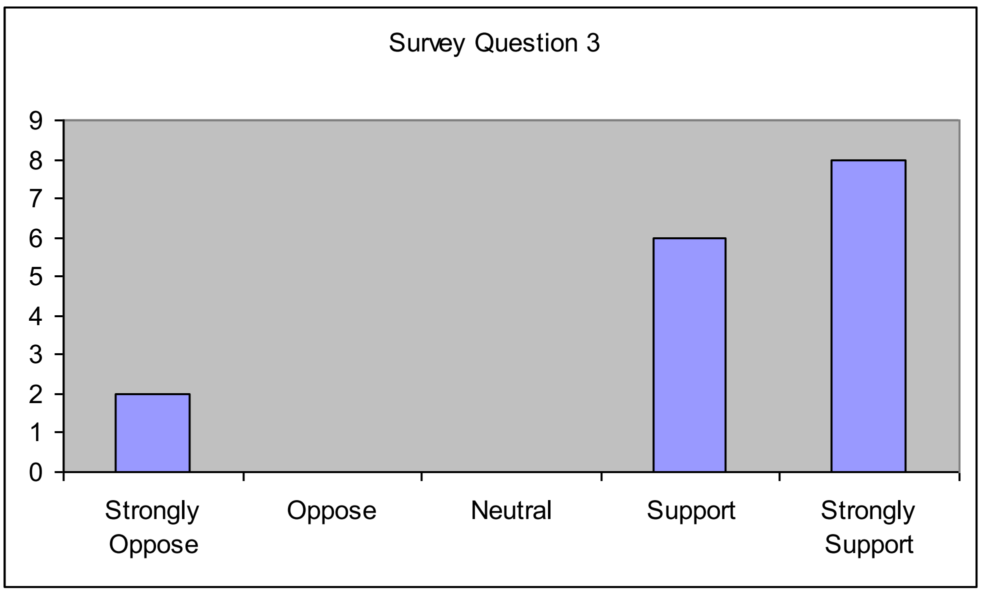

Figure 6 - Survey Question 3 Responses

The mean Likert score for this question was 4.125, with a median score of 4, indicating support for the proposal. As the responses do not clearly represent Gaussian distribution, standard deviation is not analyzed.

Further investigation of the data results indicate that, of the two respondents that indicated strong opposition to the proposal, both represented themselves as most closely identified with the utility segment of the power industry. The other self-identified utility respondent indicated support for the proposal.

Survey Question 4

The fourth survey question examined the level of support or opposition among industry professionals for having the state utility commission direct the implementation of a merit order dispatch system, should one be implemented. The responses to the question are identified in Figure 7.

The responses to this question were spread across the entire range of possible responses. 56% of respondents indicated support for the proposition, while 19% indicated opposition. 25% of all respondents indicated that they were neutral on the question.

The distribution is normal, with a mean response of 3.5625, and a median response of 4. The standard distribution for the responses is 1.7. In general, then, the proposition received support among the survey group, but this support was less than that received for either of the two previous questions.

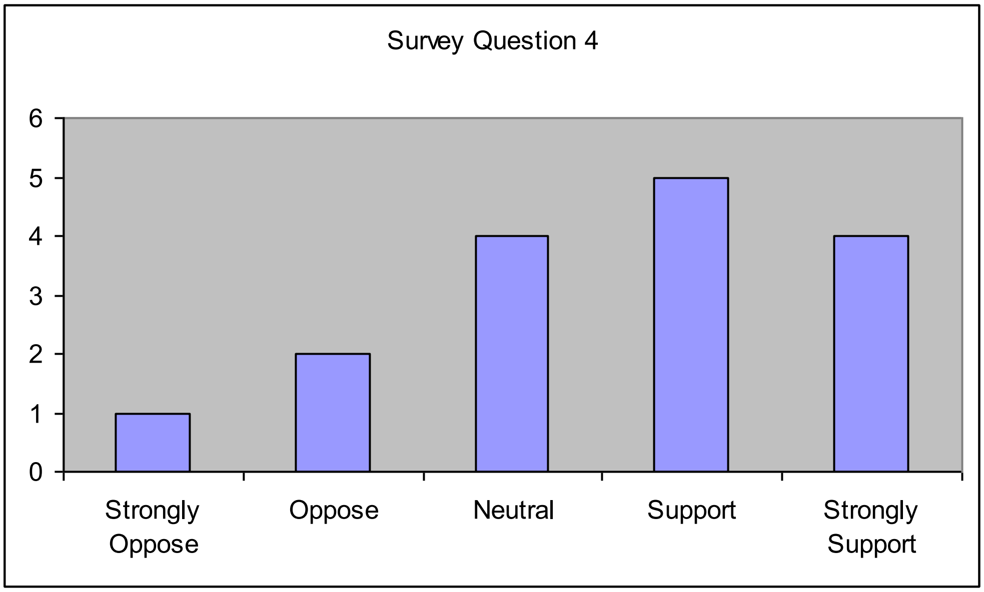

Figure 7 - Survey Question 4 Responses

Survey Question 5

Survey Question 5 asked respondents to indicate their level of opposition or support for the implementation of a market monitor to oversee the utility's operation of the transmission system and the implementation of the merit order dispatch system, should one be implemented.

81% of all respondents indicated some level of support for the idea of a market monitor. Just over half of these respondents indicated strong support for the proposition. Only 13% of respondents indicated opposition, with no strong opposition being recorded. The mean of responses is

4.125, with the median response of 4 indicating support for the proposition.

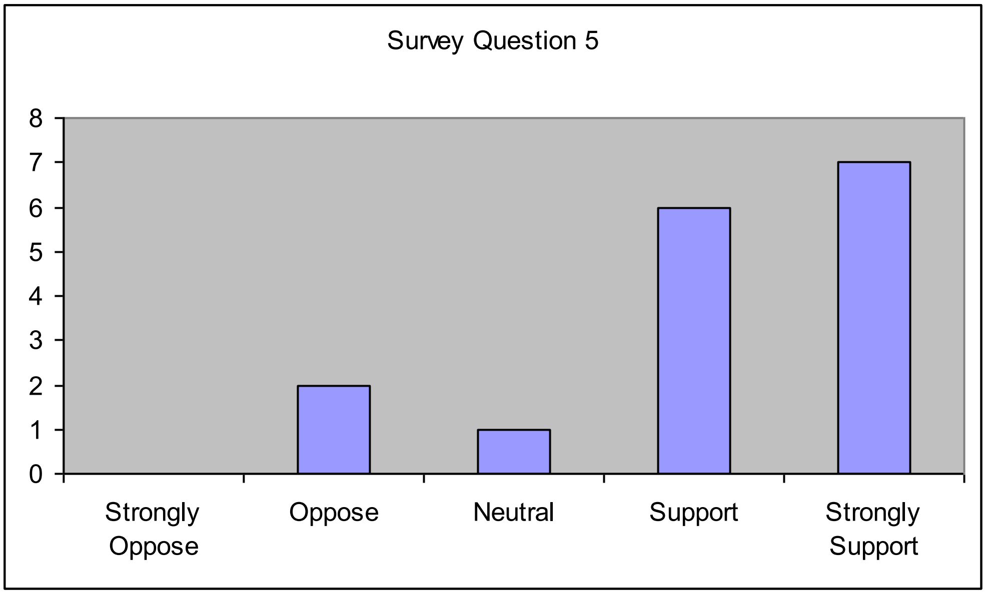

Figure 8 - Survey Question 5 Responses

The responses indicate relatively normal distribution, with two outliers indicating opposition. The deviation of Gaussian distribution applied to the responses is 0.94.

Survey Question 6

The responses to Survey Question 6 indicate a substantially different result than that seen in the previous four questions. While the responses to each of questions 2 through 5 showed, in varying degrees, support for the propositions, responses to question 6 indicate, in general, opposition to the idea of forced divestiture. 56% of respondents indicated opposition to the idea of forced divestiture to address market concentration issues, with 55% of these respondents indicating strong opposition. Only 31% of respondents indicated support, with only 13% of all respondents indicating strong support for the proposition.

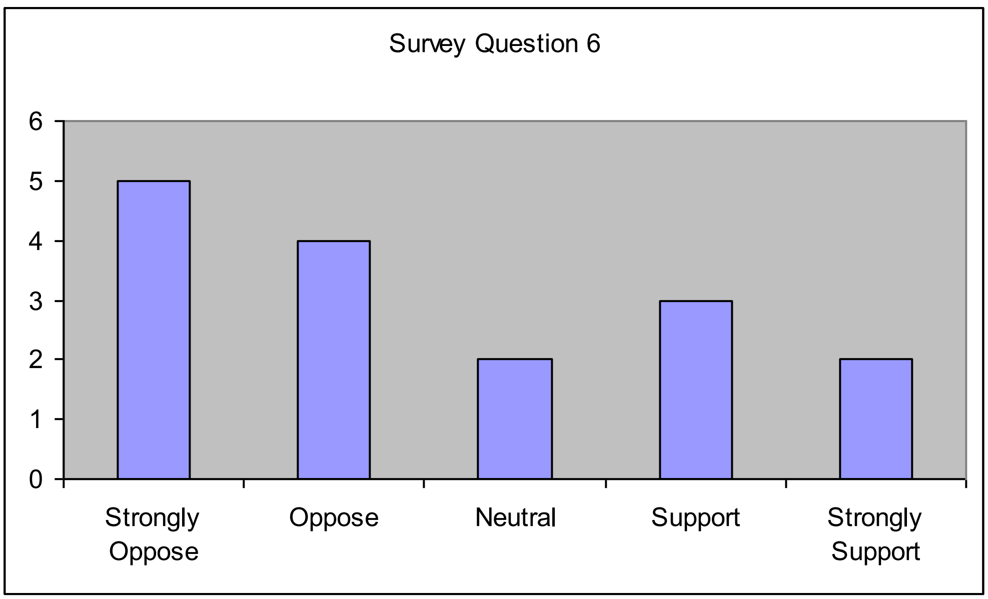

Figure 9 – Survey Question 6 Responses

The mean response for Question 6 is 2.6. The median response was 2, or indicating opposition to the proposition. The standard deviation of the responses is 1.4.

Survey Question 7

The final question on the survey instrument asked respondents to indicate, in general, whether they thought the proposals, as a whole, addressed the issues of increased utility market concentration that results from the utility purchase of a previously competitive generating asset. Figure 10 shows a histogram of the number of responses in each category.

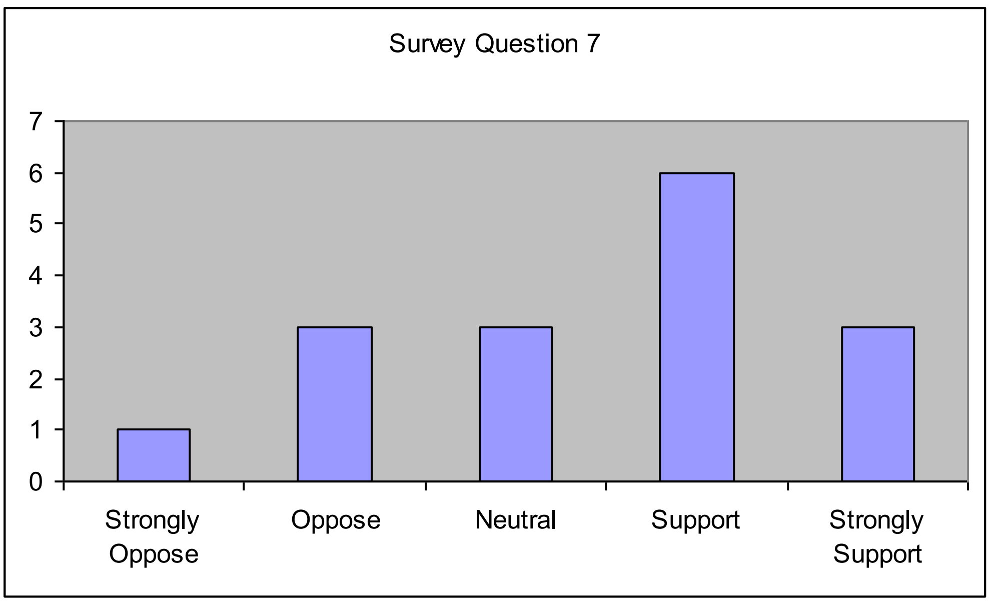

Figure 10 – Survey Question 7 Responses

56% of all respondents indicated that the proposed mitigation efforts did effectively address the market concentration concerns, while 25% of all respondents indicated that the efforts were ineffective, or inappropriate. The mean Likert score for responses is 3.4, with the median response being 4, indicating support. The distribution of responses is, generally, Gaussian, with a standard deviation of 1.2.

Case Study – OG&E / McClain Purchase Approval Application

In addition to the survey discussed above, a case study analysis is presented in order to demonstrate the effectiveness of the proposed modifications to regulatory practices. The case study involves the OG&E / McClain application approval described in Chapter 1. The actual mitigation efforts, put in place under the existing regulatory guidelines, are initially discussed. This is followed by a discussion of what mitigation efforts would be required under the proposed modified guidelines. Finally, an analysis of what actual effect these new mitigation efforts would have on the competitive nature is included.

Mitigation Required by Existing Regulatory Practices

Analysis of Effects of the Transaction

Under the existing regulatory structure, the first step in the OG&E case was an analysis of the pre-transaction market conditions, as measured by HHI. In order to accomplish this, a delivered price test was performed, per the recommendations of FERC's Merger Policy statement, Order No. 592 (FERC 1996c). This delivered price test determined what competitors could enter the market to provide a disciplining effect on OG&E's pricing structure.

The first step in a delivered price test is to determine the relevant market (FERC 1996c). Proper identification of the appropriate market extents is necessary to ensure that only those potential competitors that can actually compete and provide pricing discipline are included in the market size. Over-representation of the market would result in lower market share by the dominant firm and artificially low concentration levels. Under-representation of the market would show higher concentration levels than actual.

Applicants provided analysis for two different market areas. The first was the OG&E control area, as shown in Figure 2. The second market region proposed was that of the entire Southwest Power Pool (SPP), a much larger geographic and load area.

For comparison, the OG&E market for the Summer Super Peak period is determined to be 8,280 MW. For the same period, the Southwest Power Pool market was determined to represent 30,695 MW (FERC 2003C). Similarly, the OG&E market share for the same period in the OG&E destination market is 70.9%. In the destination market of the Southwest Power Pool, OG&E's market share is 19.8%.

Applicants argued that, as all members of the Southwest Power Pool operated under the same tariff structure, the OG&E and SPP areas are homogenous.

In this case, FERC found that the appropriate market limits were the OG&E control area. FERC determined that there were significant transportation restrictions that substantially isolated the OG&E control area from other systems. These restrictions, referred to as transmission flowgates, significantly limit the amount of electric energy that can flow into the OG&E control area, particularly during high load, high price conditions.

Because the control area is isolated from other areas, FERC determined that considering the OG&E control area as the destination market for the delivered price test was a more accurate representation of the actual market conditions. This same rationale will be followed in the analysis of the case study in this document.

Once the destination market was determined, the delivered price test was conducted. If a competitor could physically reach the OG&E system and, based on a generating unit's *marginal* cost, provide energy at a price equal to or less than 105% of the market clearing price, then that competitor was presumed to be included in the market. Market clearing prices that were determined for the 10 seasons analyzed are shown in Table 4 (FERC 2004c). These prices are shown in dollars per megawatt-hour, which is the typical billing unit for wholesale electric energy. For comparison purposes, the marginal cost of energy from the McClain plant is considered to be $30/megawatt-hour.

Table 4 - OG&E Market Clearing Prices

SEASON EXAMINED	MARKET PRICE ($/MWH)
Summer Super Peak 1	$200
Summer Super Peak 2	$45
Summer Peak	$40
Summer Off Peak	$35
Winter Super Peak	$40
Winter Peak	$35
Shoulder Super Peak	$40
Shoulder Peak	$35

There were eight different seasons that were examined as part of this study. These seasons were defined primarily based on the expected clearing price. This, most generally, follows the load conditions of the electric system – as load in the system increases there is more transmission congestion and less available generation capacity. Thus, prices for additional energy generation and transmission are higher. Two other periods, Winter Off Peak and Shoulder Off Peak, are not included in the analysis, as the clearing price for these was lower than the delivered price for the acquired unit. During these periods, then, there would be no impact on the market due to the acquisition of the McClain unit, as the McClain unit would not be able to compete during these time periods.

For this study, summer is considered to be June, July and August. Winter is considered to be December, January and February. The Shoulder period is considered to include the months of March, April, May, September, October and November. Peak conditions are normal, daily periods of high energy usage, and off-peak periods are normal daily periods of low energy usage (nights). Super Peak periods are periods of abnormally high energy usage, that may occur only once or twice during a season. For the summer condition, there are two different load levels that are considered to be super peak conditions.

As Table 4 shows, the highest clearing price for the OG&E market ranges from a high of $200/megawatt-hour during the Summer Highest Super Peak period to a low of $35 during both the Winter Peak and Shoulder Peak conditions. The mean clearing price is $58.75/megawatt-hour. The mean value is skewed substantially by the very high clearing price that occurs during the Summer Super Peak 1 season, even though this “season” may occur for only several dozen hours during the year. A more accurate feel for the “normal” clearing price can be obtained by examining the median clearing price for these eight periods, which is $40/megawatt-hour.

As is evidenced by the values in Table 4, the price that a competitor could expect to receive for energy supplied into the OG&E market varies substantially with the season and the loading levels of the transmission system. The number of competitors, and consequently the size of the market, varies substantially as well. The size of the market in megawatts, as defined by the delivered price test, is shown in Table 5. A full analysis of each competitor’s contribution to market size is contained in the tables in Appendix A. Table 5 also depicts the size of OG&E’s presumed contribution to the market, and the resulting market share by the utility.

Examination of the data included in Table 5 shows that market size for the OG&E destination market ranges from a high of 5,871 megawatts during the Summer Super Peak 1 season to a low of 2,285 MW during the Shoulder Peak season. Due to the range in pricing of OG&E generation units, OG&E market share ranges from a high of 70.9% during the Summer Super Peak 1 period to a low of 46.7% during the Shoulder Peak period.

The amount of generation that OG&E contributes to the market varies during the different seasons based on the system clearing price, the marginal cost of operating OG&E's generation units and the physical conditions of the transmission system. During the Summer Super Peak 1 season, OG&E is able to offer 5,871 MW that have a marginal cost less than the $200/MW-HR clearing price. During periods of low clearing price, however, OG&E contributes as little as 2,285 MW.

Table 5 - Size of OG&E Market

SEASON EXAMINED	MARKET SIZE (MW)	OG&E CONTRIBUTION	OG&E MARKET SHARE
Summer Super Peak 1	8,280	5,871	70.9%
Summer Super Peak 2	8,003	5,591	69.9%
Summer Peak	5,468	3,445	63.0%
Summer Off Peak	4,867	2,858	58.7%
Winter Super Peak	6,316	3,445	54.5%
Winter Peak	5,753	2,885	50.1%
Shoulder Super Peak	5,313	2,744	51.6%
Shoulder Peak	4,890	2,285	46.7%

In all but one season, the OG&E market share exceeded 50%. The next closest competitor, in terms of potential market share, is able to achieve no higher than 17.5% of the market. In all but two of the time periods, the closest potential competitor is able to garner less than 15% of the potential market. The mean value of OG&E market share is 58.2%, while the median value is 56.6%.

This analysis shows that the OG&E market, as the destination market, clearly contains a dominant firm, in OG&E, and a minimal competitive fringe. A full representation of the potential market shares of each competitor that meets the delivered price test is included in the tables of Appendix A.

It is useful to note that the values in Table 5 are representative of the *potential* competitors in the OG&E control area market. In actuality, OG&E made 100% of all wholesale and retail electric energy sales during the time periods examined.

OG&E, in practice, is both the supplier and purchaser of wholesale energy for the large majority of the market under analysis (FERC 2004c). OG&E, therefore, is in a position to maximize its profits by choosing the level of output of its generating facilities and purchasing from competitors only the marginal energy that it chooses not to produce. Thus, the values in Table 5 understate the market share that OG&E controls.

The remaining wholesale customers in the OG&E control area have the option of purchasing either from OG&E, or from the market. In actuality, OG&E makes 100% of the wholesale sales to these customers.

It is likely that this is the result of price discrimination on the part of OG&E, as discussed in Chapter 2. It is this form of market power, and the increased ability and incentive to exercise this market power that is the concern of FERC and competitors to OG&E.

Once the delivered price test is concluded, it is necessary to measure concentration using the Herfindahl-Hirschman Index (HHI), as it is defined in FERC Orders 592 and 642 (FERC 1996c, FERC 2000c). Initially, the HHI analysis is completed for the pre-transaction scenario. The resulting HHI values for the OG&E market prior to the purchase of the McClain facility are shown in Table 6.

Table 6 - Pre-Transaction HHI Analysis

SEASON EXAMINED	OG&E MARKET SHARE	PRE-TRANSACTION HHI
Summer Super Peak 1	70.9%	5,114
Summer Super Peak 2	69.9%	4,973
Summer Peak	63.0%	4,121
Summer Off Peak	58.7%	3,638
Winter Super Peak	54.5%	3,283
Winter Peak	50.1%	2,895
Shoulder Super Peak	51.6%	3,009
Shoulder Peak	46.7%	2,570

HHI values in the pre-transaction market range from a low of 2,285 in the Shoulder Peak period to a high of 5,591 in the Summer Super Peak 2 period. All of these values are in excess of the 1,800 screen level that FERC has determined represents a highly concentrated market. The mean value of HHI for the examined periods is 3,700. The median value of HHI in the pre-transaction market is 3,460.

Once the analysis of the market in the pre-transaction state is complete, a similar analysis must be completed for the post-transaction market. The same delivered price test is run for the post-transaction market. Table 7 shows that the total market size for each of the seasons is identical to the pre-transaction scenario. Logically, this is expected. There have been no new generators added to the market. The physical configuration of all generators is identical to the pre-transaction state. The only change is that the amount of supply (generation) that is provided by the McClain facility is now being controlled by OG&E, rather than an OG&E competitor. This increases the OG&E contribution by nearly 400 MW. Additionally, there is a decrease of 400 MW from competitor's offerings. This serves to substantially increase the OG&E market share, as shown in Table 7

.

Table 7 – Post-Transaction Market Share

SEASON EXAMINED	MARKET SIZE (MW)	OG&E CONTRIBUTION	OG&E MARKET SHARE
Summer Super Peak 1	8,280	6,247	75.5%
Summer Super Peak 2	8,003	5,967	74.7%
Summer Peak	5,468	6,821	70.0%
Summer Off Peak	4,867	3,234	66.6%
Winter Super Peak	6,316	3,821	60.5%
Winter Peak	5,753	3,261	56.7%
Shoulder Super Peak	5,313	3,039	57.4%
Shoulder Peak	4,890	2,580	52.8%

While market share in the pre-transaction analysis ranged from a low of 46.7%, and a high of 70.9%, market share in the post-transaction analysis ranges from a low of 52.8% during the Shoulder Peak to 75.5% during the Summer Super Peak 1 period. This is an increase in the range of 5% for each of the seasons examined. The mean value of market share has increased from 58.2% to 64.3%, while the median value has increase from 56.6% to 63.6%.

Not only has there been an increase in OG&E market share, there has been an equivalent decrease in the market share offered by competitors. Thus, the impact on concentration of the market is doubled, as compared to construction of a new facility, or to a competitor's assets being removed from the market due to financial failure.

Once the delivered price test is completed for the post-transaction scenario, it is necessary to measure the concentration of the post-transaction market using the HHI index. The results of this analysis are shown in Table 8. Tables showing the complete contribution of each competitor are contained in Appendix A.

Table 8 – Post-Transaction HHI

SEASON EXAMINED	OG&E MARKET SHARE	POST-TRANSACTION HHI
Summer Super Peak 1	75.5%	5,770
Summer Super Peak 2	74.7%	5,643
Summer Peak	70.0%	4,999
Summer Off Peak	66.6%	4,554
Winter Super Peak	60.5%	3,932
Winter Peak	56.7%	3,549
Shoulder Super Peak	57.4%	3,601
Shoulder Peak	52.8%	3,144

HHI values in the post-transaction market range from a high of 5,770 during the highest summer super peak, to a low of 3,144 during the Shoulder Peak period. This is compared to a range of 5,114 to 2,285 in the pre-transaction marketplace. Mean values of HHI have increased from

3,700 pre-transaction to 4,399 post-transaction. The median value has a similar increase, from 3,460 pre-transaction to 4,243 post-transaction.

Table 9 compares each season's HHI values in the pre-transaction and post-transaction states. This analysis shows during which seasons the transaction would have the most anti-competitive effects and provides a measure of the severity of these anti-competitive effects (FERC 1996c).

Table 9 - HHI Delta Analysis

SEASON EXAMINED	PRE-TRANSACTION HHI	POST-TRANSACTION HHI	HHI DELTA
Summer Super Peak 1	5,114	5,770	656
Summer Super Peak 2	4,973	5,643	670
Summer Peak	4,121	4,999	878
Summer Off Peak	3,638	4,554	916
Winter Super Peak	3,283	3,932	648
Winter Peak	2,895	3,549	655
Shoulder Super Peak	2,744	3,601	592
Shoulder Peak	2,285	3,144	574

HHI delta, or change in HHI as a result of the transaction, ranges from a minimum of 574 for the Shoulder Peak period to a maximum of 961 during the Summer Off-Peak season. The mean value of HHI delta, as a result of the OG&E / McClain transaction is 699 basis points. The median value is 666.

The HHI delta values shown in Table 7 are compared to the FERC merger screen analysis which says that, in highly concentrated markets such as the OG&E market, HHI increase in excess of 50 give rise to anti-competitive concerns, while HHI increases in excess of 100 show a transaction that is presumed to be anti-competitive.

To summarize the analysis above, the market is extremely highly concentrated and HHI delta values are well in excess of the 100 point threshold that FERC has determined presumes an anti-competitive transaction (FERC 1996c, FERC 200c). Thus, FERC would require further study and analysis of the mitigation efforts that would need to take place in order to offset the anti-competitive nature of the transaction.

Efficiency and Failing Firm Analyses

FERC recognizes that, in some cases, there are circumstances that would make an acquisition that initially appears to be anti-competitive, to actually be beneficial for the public good. The next two steps in the analysis, the efficiency test and the failing firm analysis, determine whether any of these conditions exist. If so, and the benefits from these analyses offset the detriments of increased concentration in the marketplace, then the acquisition would be approved.

Step 4 of the merger policy statement makes an allowance for a transaction to proceed, despite its anti-competitive market effects, if the applicants can show that there are efficiency gains that could not be realized outside of the transaction (FERC 2000c). In the study case, no such efficiency gains were shown (FERC 2004c). The McClain facility would continue to operate under the same basic conditions that existed prior to the transaction, as would the marketplace in general.

This is evidenced by the fact that the market clearing prices did not change in the post-transaction marketplace, as compared to pre-transaction. Should there be any increased market efficiencies, clearing prices would be decreased to represent the benefits of this increased efficiency.

Similarly, the OG&E/McClain purchase did not meet the failing-firm analysis described in Step 5 of the merger policy statement (FERC 20004c). The failing firm analysis requires that the assets of a firm be in risk of exiting the market, should the proposed acquisition not take place. The McClain facility, despite the fact that it had filed for Chapter 11 bankruptcy, was not in risk of exiting the market, based on the analysis conducted by FERC (FERC 2004c).

As a point of fact, the McClain facility did not file for bankruptcy until after the purchase agreement had been signed. The bankruptcy was simply a means to facilitate the purchase (OG&E 2004). Prior to the bankruptcy filing, the McClain facility was one of only 5 NRG owned facilities that was contributing positive cash flow to the corporation (FERC 2004b). OG&E, likewise, was in no risk of failing if the merger did not go through. FERC determined that, due to these reasons, the failing firm defense could not be applied to the transaction, as proposed by OG&E and NRG McClain, LLC.

Mitigation Efforts Required

Since the HHI delta exceeds the threshold levels set by FERC, mitigation efforts are required (FERC 1996c). Current regulatory practices assume that the Bertrand economic model represents the conditions present in the utility market. Specifically, the tenets of the Bertrand Paradox, as described in Chapter 2, are assumed. That is, only two competitors are necessary to ensure perfect competition. This is represented by the mitigation required in the study case.

In order to offset the anti-competitive effects of the transaction, OG&E and FERC staff argued that it is only necessary to expand the market by the amount of generation that was removed as a competitor to

OG&E during the transaction. The method of market expansion chosen in this case was upgrades to the transmission system that would remove restrictions and allow competitive generation access to the OG&E market that could not physically be competitive prior to the transaction.

OG&E, through its purchase of the McClain facility, gained control of 400 MW of generation that was previously a theoretical competitor to OG&E for wholesale sales of electricity. The amount of the increase, then, need only be equal to the 400 MW that was the result of the acquisition. According to the existing practices of FERC and its staff, this would completely replace the amount of generation that is no longer offered as an alternative to OG&E generation, and thus would leave the market unchanged (FERC 2004b).

In order to achieve this expansion of potential competitive supply, OG&E, and as a result FERC, chose a single competitor that did not currently have physical access to the OG&E market. A number of transmission system upgrades were suggested by OG&E that would, allegedly, allow this competitor to potentially compete, up to 400MW, with wholesale purchases made in the OG&E control area. The physical upgrades that were required as mitigation efforts are listed in Table 10.

Table 10 - Physical Upgrades Necessary - Existing Guidelines

FACIILTY	UPGRADE REQUIRED
Draper Substation	Install third 345 / 161 kV Transformer and associated buswork / breakers
Morgan-Mustang 138kV line	Upgrade from 287 MW to 392 MW
Memorial – Skyline 138kV line	Upgrade from 287 MW to 331 MW

OG&E estimated that the costs of these upgrades would be near $7,000,000. It was estimated that the upgrades could be completed within 11 months of approval of the transaction by FERC.

FERC regulations require that potential mitigation efforts undergo an HHI analysis to determine their effectiveness (FERC 1996c). According to the regulations promulgated in FERC Order 592 and FERC Order 642, the purpose of this analysis is to ensure that the mitigation efforts perform the functions for which they are intended.

The purpose of the transmission upgrades, suggested by OG&E and accepted by FERC, was to expand the size of the destination market, as described above. In practice, however, the mitigation upgrades do not expand the market by the entire 400 MW. Table 11 shows the destination market size prior to the transaction and after mitigation. As can be seen, in summer seasons, the market is expanded by approximately 100 MW. In winter seasons, the market size is essentially unchanged. In shoulder seasons, the size of the market is actually reduced slightly.

Table 11 – Post-Mitigation Market Size

SEASON EXAMINED	PRE-TRANSACTION MARKET SIZE (MW)	POST-MITIGATION MARKET SIZE (MW)
Summer Super Peak 1	8,280	8,384
Summer Super Peak 2	8,003	8,107
Summer Peak	5,468	5,573
Summer Off Peak	4,867	4,973
Winter Super Peak	6,316	6,314
Winter Peak	5,753	5,753
Shoulder Super Peak	5,313	5,295
Shoulder Peak	4,890	4,886

The reasons for this can be determined from the specifics of the market analysis, as shown in Appendix A. The single competitor chosen by FERC for increase in available transmission capacity is located inside the OG&E control area. As generation from this potential competitor is increased, the amount of generation that can enter the OG&E control area from outside sources is reduced. As a potential competitors' available generation falls under the amount of the smallest wholesale contract in the destination market, the competitor is removed from the analysis, since the supplier is no longer a viable competitor.

Table 12 shows the associated OG&E market share after mitigation efforts are imposed. Comparison to Table 8 shows that OG&E market share remains static or slightly decreases in all seasons.

Table 12 – Post-Mitigation Market Share

SEASON EXAMINED	MARKET SIZE (MW)	OG&E CONTRIBUTION	OG&E MARKET SHARE
Summer Super Peak 1	8,384	6,247	74.5%
Summer Super Peak 2	8,107	5,967	73.6%
Summer Peak	5,573	3,821	68.6%
Summer Off Peak	4,973	3,234	65.0%
Winter Super Peak	6,314	3,821	60.5%
Winter Peak	5,753	3,261	56.7%
Shoulder Super Peak	5,295	3,039	57.4%
Shoulder Peak	4,890	2,580	52.8%

The HHI analysis for the post-mitigation destination market is shown in Table 13. As Table 13 shows, the HHI Delta values greatly exceed FERC's competitive screen analysis even after the mitigation efforts are put into place. The mean HHI delta has decreased from 699 to 622 as a result of the mitigation. The median HHI value has decreased from 656 to 620.

Table 13 – Post-Mitigation HHI Analysis

SEASON EXAMINED	PRE-TRANSACTION HHI	POST-MITIGATION HHI	HHI DELTA
Summer Super Peak 1	5,114	5,629	515
Summer Super Peak 2	4,973	5,501	528
Summer Peak	4,121	4,831	710
Summer Off Peak	3,638	4,391	753
Winter Super Peak	3,283	3,932	648
Winter Peak	2,895	3,549	655
Shoulder Super Peak	2,744	3,601	592
Shoulder Peak	2,285	3,144	574

Mitigation Required by Modified Regulatory Practices

Under the modified regulatory practices that are the focus of this study, the first several steps of transaction analysis are identical. The delivered price test is used to define the destination market. Concentration of the pre-transaction market is measured by calculating HHI values. The post-transaction market is determined and concentration is measured by HHI. If the HHI delta exceeds the threshold values, then the efficiency and failing firm test are examined. The information in Table 4 - Table 9, then, would remain unchanged.

Should mitigation be required, however, the modified practices demand a significantly different result. The key points of the modified practices are outlined again below.

1. At a minimum, if a utility proposes potential new entry to combat increased market concentration, this potential new entry must be sufficient to bring the market concentration back to a point where it would pass the Commission's Competitive Screen Analysis (HHI increases below 100 for highly concentrated markets).
2. In order to address the increases in generation market power, and to prevent the utility from using its new generation purchases to further foreclose competitors from the market, opportunity must be given to competitors to actually deliver competitive generation into the market. At a minimum, competitors need to be allowed to compete on a wholesale basis directly with the affiliated generation in order to deliver the amount of generation that was called out as potential new entry through transmission expansion.
3. In the absence of an RTO, the utility's operation of the transmission system must be effectively monitored in order to prevent foreclosure of a competitive generator's access to the

transmission system, including exercise of its increased buyer market power. An effective market monitor will not only address transmission issues (such as calculation of ATC, TTC, posting on OASIS, etc.), but will also oversee the implementation of mitigation of generation market power.

4. In order to ensure that competitive wholesale supply is balanced with the interests of the retail consumer, the process of allowing potential suppliers access to become actual suppliers most often should be implemented under the direction of the state utility commission. This commission is already tasked with overseeing the utility's acquisition of generation and is in the best position to direct this process.
5. As an alternative, the Commission could order a 1 to 1 divestiture of generation by the utility. This will eliminate the short term market power issues, as well as reduce future problems, such as potential stranded cost recovery and the utility's increased incentive and ability to exercise both transmission and generation market power.

Applying these modified regulatory practices to the study case yields a substantially different result from the existing mitigation efforts, as described in the analysis above. A comparison of market concentration in the pre-transaction and post-transaction markets is shown in Table 9. An analysis of the post-mitigation market indicates that the destination market must be expanded by some 815 MW in order for concentration levels to fall to the point that they meet the FERC competitive screens. Tables that show the complete market share, concentration and HHI analysis for this step are shown in Appendix B.

The number and cost of upgrades necessary to reduce the HHI value to levels that pass the competitive screen is substantially larger than the list shown in Table 10. The list of upgrades necessary for complete mitigation of increases in market concentration as proposed by the modified regulatory practices is shown in Table 14. While no complete cost estimate is available for this list of upgrades, it is logical that the cost would greatly exceed the $7,000,000 that was imposed as part of the case settlement.

Table 14 - Upgrades Necessary for Complete Mitigation of Concentration

FACILITY	PRE TRANSACTION RATING (MW)	MW REQUIRED FOR 815 ATC
Morgan - Mustang 138	287	452
Draper 345 / 138kV Transformer Ckt 1	493	638
Draper 345 / 138kV Transformer Ckt 2	493	615
Pecan Creek 345/161kV Xformer	370	380
Hemlock Tap - NE Enid 69kV	48	49
Memorial - Skyline 138	287	403
NW 345/138 Transformer	493	387
Cimarron - Czech Hall 138kV	382	425
Eastern Ave - Memorial Skyline 138kV	191	234
Mission Hill - Shawnee 69kV	51	64
Lone Oak - Quail Creek 138kV	308	358
Paoli 138/69kV Transformer	50	52
Arcadia - KAMO Memorial 138kV	287	399
Forrest Hill - Tecumseh 69	72	84
Division Ave - Haymaker 138	287	323
Arcadia 345/138kV Xformer #1	493	590
Remington Park - Stonewall 138kV	191	205
Arcadia - Redbud ckt 2 345kV	1195	1495
Arcadia - Redbud ckt 1 345kV	1195	1493
Horseshoe Lake - KAMO Memorial 138kV	287	360
Czech Hall - Xerox 138kV	382	422
Arcadia 345/138kV Xformer #2	493	571
Cleveland Tap - S 4th St 69	92	92
Division Ave - Silver Lake 138kV	287	306
Eastern Ave - OMPA Edmond Hafer 138	287	303
Arcadia - Horseshoe Lake 138	287	303
E Cntrl Henryetta - Okmulgee 138kV (AEP West)	105	111
Carthage Sub - Atlas Jct 161 kV (EMDE - SWPA)	167	167
Chamber Springs - Tontitown 161kV (AEP West)	244	244
east Central Henryetta - Weleetka 138kV (AEP West)	105	107

The market size, as shown in Table 15, is greatly expanded through the upgrades described in Table 14. OG&E's Market Share has a mean of 56.7% and a median value of 55.4% in this condition.

Table 15 - Modified Mitigation Market Size and Market Share

SEASON EXAMINED	MARKET SIZE (MW)	OG&E CONTRIBUTION	OG&E MARKET SHARE
Summer Super Peak 1	9,084	6,247	68.8%
Summer Super Peak 2	8,807	5,967	67.8%
Summer Peak	6,273	3,821	60.9%
Summer Off Peak	5,673	3,234	57.0%
Winter Super Peak	7,104	3,821	53.8%
Winter Peak	6,543	3,261	49.8%
Shoulder Super Peak	6,084	3,039	50.0%
Shoulder Peak	5,680	2,580	45.4%

The results of the upgrades are that HHI delta values are now low enough to pass FERC's competitive screen analysis. This comparison is shown in Table 16.

Table 16 - Modified Mitigation HHI Delta Analysis

SEASON EXAMINED	PRE-TRANSACTION HHI	POST-MODIFIED MITIGATION HHI	HHI DELTA
Summer Super Peak 1	5,114	4,935	-173
Summer Super Peak 2	4,973	4,812	-161
Summer Peak	4,121	4,106	-15
Summer Off Peak	3,638	3,737	99
Winter Super Peak	3,283	3,311	28
Winter Peak	2,895	2,993	99
Shoulder Super Peak	3,009	3,024	15
Shoulder Peak	2,285	2,669	99

Upgrades that allow the destination market to pass the competitive concentration screen have the effect of reducing concentration in other seasons to levels of concentration below the pre-transaction market. This resulting decrease in concentration implies an increase in competition, a stated goal of FERC.

A further sanity check can be run on the results of the modified analysis. As market concentration levels, measured by HHI, are a direct result of market share analyses, it is expected that OG&E market share levels would be much nearer to pre-transaction levels after the modified mitigation levels are imposed, as compared to the existing mitigation levels. This comparison is shown in Table 17. This table shows that, under the existing mitigation practices, market share expands relatively substantially over the pre-transaction conditions. Under the modified regulatory practices, however, OG&E market share decreases minimally in all seasons. This matches the HHI delta analysis that was shown in Table 16.

Table 17 - Market Share Comparison

SEASON EXAMINED	PRE-TRANSACTION MARKET SHARE	EXISTING MITIGATION MARKET SHARE	MODIFIED MITIGATION MARKET SHARE
Summer Super Peak 1	70.9%	74.5%	68.8%
Summer Super Peak 2	69.9%	73.6%	67.8%
Summer Peak	63.0%	68.6%	60.9%
Summer Off Peak	58.7%	65.0%	57.0%
Winter Super Peak	54.5%	60.5%	53.8%
Winter Peak	50.1%	56.7%	49.8%
Shoulder Super Peak	51.6%	57.4%	50.0%
Shoulder Peak	46.7%	52.8%	45.4%

CHAPTER 5 SUMMARY, RECOMMENDATIONS AND CONCLUSIONS

Summary

The purpose of this study was to determine what, if any, changes need to be made to existing federal regulatory practices governing the purchase of non-utility competitive generation in a utility control area, by the dominant utility. The impetus for the study was the increasing number of this type of acquisition that is expected in the near future. This increase is expected due to the large number of merchant generating facilities that have been constructed in recent history, the financial instability of many of these generating stations, and the changing utility environment that tends more and more to a deregulated, competitive environment, as opposed to the historic monopolistic, regulated environment.

Significant federal regulation dealing with utilities, dating as far back as the 1930's, was examined to determine the current regulatory environment and the history behind it. After the initial regulatory acts in the 1930's, significant federal utility legislation was largely absent until the late 1970s. In the 1990s, the quantity and aggressiveness of federal utility legislation was significantly increased. The tone and quantity of changes to federal legislation has continued in the early parts of the new century.

These changes to federal legislation, without exception, have moved to encourage transition to a competitive utility environment. Despite this, only a very small portion of the country has moved into a fully competitive, deregulated marketplace. The rest of the country operates in a quasi-competitive marketplace. Some areas of the power market, such as transmission system access, are operated in a relatively open, competitive environment. Others, such as provision of electric energy to retail customers, operate in an antiquated, regulated, monopolistic environment. Utilities that operate in these parts of the country have the challenges and opportunities that come about by operating in a mixed environment.

One such area of overlap between regulated and competitive exists in the production and sale of electric energy. Utilities, in the quasi-competitive areas of the country, operate both as a producer of electric energy and as a purchaser of electric energy for eventual sale to the utility's retail load base. While the retail sales are regulated, the wholesale sale and purchase of energy is not. In many of these areas, competitive generating stations have been constructed with the intent of competing for this wholesale load. These plants are most often constructed with state of the art technology and offer energy through more efficient, cleaner and more responsive processes. It would be expected that these facilities would thrive.

In practice, however, many of these generators are undergoing marked financial distress. Whether from inability to penetrate the wholesale market, financial problems, or the refusal of the utility to purchase energy from these low cost, efficient, clean facilities, many generators have been forced to examine divestiture.

When these efficient facilities are sold, the purchase is subject to the approval of the Federal Energy Regulatory Commission (FERC). The charge of FERC is to ensure that the purchase is in the "public interest." Specifically, does the transaction create a market environment that benefits or harms competition?

When a utility proposes to purchase a generating facility in its control area, significant questions arise regarding the anti-competitive nature of the marketplace after the transaction. Although federal regulation, as written, encourages move toward competition, existing federal regulatory practices for these type transactions do not protect competition in the utility marketplace. Examination of the existing practices showed deficiencies in three key areas: inability to address vertical market power, ineffective treatment of increases in market concentration, and a lack of focus on the long-term impacts of the transaction.

With these deficiencies in mind, a new set of regulatory practices was proposed as part of this study. These practices are fully supported by the existing federal regulations. In fact, the proposed practices more closely mirror the text of the legislation and the regulations than do the existing practices. Specifically, it is proposed that regulations governing purchase of a competitive generating asset by a dominant utility be modified in five ways:

- Market concentration after the transaction should be brought back to levels near those that existed before the transaction. This is brought about by increases in potential competitive supply far in excess of what is demanded under current practices.
- A competitive bid process should be implemented to ensure that the increase in competitive supply has actual access to the market.
- A market monitor should be put in place to oversee the competitive bid process, as well as the utility's operation of the transmission system.

- In order to balance competition with ratepayer's interest, implementation of the competitive bid process and the market monitor should be done under the auspices of the state regulatory commission.
- An alternative to the above four steps is forced divestiture of existing utility generation that equals in capacity the purchased generation.

Two research methods were used to determine the validity of the proposed changes.

- A survey was made of industry professionals who were knowledgeable on the topics of utility regulation, in general, and purchases of generating assets, in particular. The intent of the survey was to gauge the levels of support or opposition to the 5 tenets of the proposed regulatory changes, as well as the level of support for the changes as a group.
- A case study of a recent purchase of a competitive generating asset by the dominant utility was used to compare the effects and effectiveness of the modified

regulatory practices, as compared to existing regulatory practices.

The results of the analysis give strong evidence to support the effectiveness and appropriateness of the majority of the proposed changes.

Significant Findings

Federal legislation and regulations support competition

Through the historical research of federal legislation and regulation dealing with the utility market, it was found that, since the 1970's, federal regulation and legislation have consistently favored an increasingly competitive utility marketplace. Beginning with the Energy Policy Act of 1977 (EPACT), continuing with the Public Utility Regulatory Policy Act of 1978 (PURPA), and the modifications to the EPACT in 1992, legislation passed by the US congress has increasingly favored competition in the utility environment.

FERC has attempted to meet the goals of these legislative acts by promulgation of regulations that increasingly require competitive practices in the utility market. FERC Orders 592, 642, 888, 889, 2000, 2000-A, 2003 and 2004 have all had significant impacts on the requirements of utility markets to transition to a competitive marketplace.

Current regulatory practices are ineffective in dealing with generator purchases by utilities

Despite the strength of support for competition stated in federal legislation and regulations, the practices involved in implementing these regulations do not consistently protect competition. Of primary interest to this study is the application of these practices as it relates to purchases of competitive generating assets by a utility. Current practices apply regulations designed to examine market impacts of utility mergers to such acquisitions. These practices are wholly ineffective in dealing with the specific market impacts of the studied acquisitions.

When an asset purchase is found to have anti-competitive impacts on the marketplace, FERC demands that mitigations be put in place to counteract these negative impacts. The extent of mitigations demanded by current regulatory practice, however, do not effectively address the anticompetitive effects that FERC recognizes. This is most strikingly noticed by examining the mitigations as if they were part of the existing purchase agreement.

In the study case, if the mitigations required by FERC were proposed, not as mitigations, but as part of the original purchase proposal by the utility, then the marketplace created by the proposed acquisition, including mitigations, would fail the Commission's competitive screen analysis. If these mitigations would not be appropriate when completed voluntarily as part of a purchase agreement, then they are not appropriate for dealing with the effects of the transaction as part of the regulatory process.

The proposed changes effectively address the deficiencies of current practices

Comparison of the proposed regulatory changes, as applied to the case study, shows that all three areas of deficiency in the existing regulatory practices are addressed.

- Market concentration (horizontal market power) is addressed by requiring increased potential supply to reduce market share and market concentration to levels that would pass FERC, DOJ and FTC requirements.
- Competitive bid process for this increased potential supply ensures that the increased potential supply has appropriate access to the marketplace. Additionally, a competitive bid process decreases the utility's incentive to operate its transmission system in

a way which would disadvantage potential competitors.

- Implementation of a market monitor decreases the utility's ability to operate its transmission system in a way which would disadvantage competitors.
- The long term impacts of the transaction are dealt with by ensuring that there are no additional barriers to entry put in place by increases in market concentration, or the ability and incentive of the utility to foreclose competitors from the market.
- Alternatively, divestiture of an equal amount of generation by the utility addresses all three areas of concern by creating a marketplace environment that is as close as possible to that which existed before the transaction.

Most areas of proposed changes have support among industry professionals

The results of the survey show that three out of the four changes to the regulatory process have a significant level of support among the survey group.

- 69% of survey respondents indicated support for increasing potential competitive supply to the point that market share, and market concentration, would be near to pre-transaction levels. 13% opposed this proposal.
- 88% of survey respondents indicated support for the concept of a competitive bid process to ensure that potential supply has an actual chance to compete. 13% opposed this proposal
- 56% of respondents indicated support for the bid process to be overseen by the state regulatory commission, compared with 19% that opposed the idea.
- 81% of respondents supported the idea of a market monitor to oversee utility practices as they relate to operation of the transmission system and implementation of the competitive bid process.
- 56% of respondents indicated that the proposed changes, as a whole, effectively addressed the market issues that arise during the studied

transactions. 25% of respondents opposed the idea that the changes were effective.

Forced divestiture of generating assets does not have broad support

Survey results indicate that one area of proposed changes did not enjoy support among the industry professionals surveyed. The proposal to force divestiture of utility generating assets as an alternative to implementation of the other aspects of the modification process was opposed by a significant portion of the study group. 56% of the survey respondents indicated opposition to the idea of forced divestiture as on option, while only 13% of respondents supported the idea. Of those that oppose, 55% indicated that their opposition to the idea was strong.

Recommendations and Conclusions

As a result of the study, it is recommended that implementation of the first four of the proposed regulatory modifications would effectively address the issues arising from the utility purchase of competitive generating assets. Not only does the mathematical review by application to a case study support the effectiveness of these practices, a survey of power industry professionals representing a broad segment of the power industry shows that these four proposals enjoy high levels of support.

The issue of forced divestiture as an alternative, however, is an area where future research could be beneficial before implementation. While the mathematical examination indicates that this alternative would be effective, and would not place an undue burden on the utility, the lack of support from industry professionals raises questions about the appropriateness of this proposal.

Areas for further research

Additional related areas of research that would be beneficial to the understanding of the broader topics include the following:

- Investigation into appropriate regulatory treatment of regulated utility purchases of generating assets from affiliated, unregulated entities.
- Examination of reasons behind financial distress of modern, efficient generating facilities.
- Effectiveness of current regulatory practices in offsetting the negative market impacts from utility mergers.

- Examination of reasons behind slow implementation of a competitive marketplace in large areas of the country.

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Appendix A – Market Share and HHI Analysis for OG&E Market

Destination Market	OKGE					
Analysis Type	EC					
Transmission Allocation	Pro Rata					
Period	Highest Summer Super Peak					
Destination Market Price	200					
HHI	5,114		5,770		5,629	
Change in HHI			656		515	

		Pre Acquisition			**Post Acquisition**			**W/ Mitigations**	
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	5,871	70.9	5,028	6,247	75.5	5,707	6,247	74.5	5,552
NRG	388	4.7	22	24	0.3	0	24	0.3	0
SCI									
SPS_OKGE	200	2.4	6						
INTR OGE	431	5.2	27	431	5.2	27	546	6.5	42
ONEOK	302	3.6	13	302	3.7	13	302	3.6	13
OMPA	258	3.1	10	258	3.1	10	258	3.1	9
Adjustment				-5	-0.1	0	-5	-0.1	0
CSW SPP	134	1.6	3	164	2.0	4	164	2.0	4
WR	101	1.2	1	123	1.5	2	123	1.5	2
ENT	98	1.2	1	120	1.5	2	120	1.4	2
GRRD	89	1.1	1	109	1.3	2	109	1.3	2
KMI	56	0.7	0	68	0.8	1	68	0.8	1
WEFA	52	0.6	0	63	0.8	1	63	0.8	1
AECI	46	0.6	0	56	0.7	0	56	0.7	0
EDE	37	0.4	0	45	0.5	0	45	0.5	0
CALPINE	24	0.3	0	29	0.4	0	29	0.3	0
UTILICOR	24	0.3	0	29	0.4	0	29	0.3	0
SWEPA	21	0.3	0	26	0.3	0	26	0.3	0
KCPL	18	0.2	0	22	0.3	0	22	0.3	0
EXELON	16	0.2	0	20	0.2	0	20	0.2	0
KAMO	15	0.2	0	18	0.2	0	18	0.2	0
AMEREN	13	0.2	0	16	0.2	0	16	0.2	0

ENT_TDU	13	0.2	0	16	0.2	0	16	0.2	0
CELE	12	0.1	0	15	0.2	0	15	0.2	0
DUKE	10	0.1	0	12	0.1	0	12	0.1	0
PAN_ENT	10	0.1	0	12	0.1	0	12	0.1	0
TVA									
DYNERGY	7	0.1	0	9	0.1	0	9	0.1	0
NPPD	7	0.1	0	9	0.1	0	9	0.1	0
ALLIANT	6	0.1	0	7	0.1	0	7	0.1	0
SIKE	6	0.1	0	6	0.1	0	6	0.1	0
LES	5	0.1	0	6	0.1	0	6	0.1	0
MIDAM	5	0.1	0	6	0.1	0	6	0.1	0
OC_ENT	5	0.1	0	6	0.1	0	6	0.1	0
Total	**8,280**	100.0	5,114	**8,269**	100.0	5,770	**8,384**	100.0	5,629

Destination Market	OKGE
Analysis Type	EC
Transmission Allocation	Pro Rata
Period	High Summer Super Peak
Destination Market Price	200

	Pre Acquisition	Post Acquisition	W/ Mitigations
HHI	4,973	5,643	5,501
Change in HHI		670	528

	Pre Acquisition			Post Acquisition			W/ Mitigations		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	5,591	69.9	4,881	5,967	74.7	5,574	5,967	73.6	5,417
NRG	380	4.7	23	14	0.2	0	14	0.2	0
SCI									
SPS_OKGE	200	2.5	6						
INTR OGE	431	5.4	29	431	5.4	29	546	6.7	45
ONEOK	302	3.8	14	302	3.8	14	302	3.7	14
OMPA	257	3.2	10	257	3.2	10	257	3.2	10
CSW SPP	141	1.8	3	172	2.2	5	172	2.1	5
GRRD	98	1.2	1	120	1.5	2	120	1.5	2
WR	98	1.2	1	120	1.5	2	120	1.5	2
ENT	91	1.1	1	111	1.4	2	111	1.4	2
WEFA	64	0.8	1	78	1.0	1	78	1.0	1
KMI	57	0.7	1	70	0.9	1	70	0.9	1
AECI	45	0.6	0	55	0.7	0	55	0.7	0
EDE	35	0.4	0	43	0.5	0	43	0.5	0
CALPINE	25	0.3	0	31	0.4	0	31	0.4	0
KCPL	24	0.3	0	29	0.4	0	29	0.4	0
SWEPA	21	0.3	0	26	0.3	0	26	0.3	0
EXELON	20	0.2	0	24	0.3	0	24	0.3	0
UTILICOR	20	0.2	0	24	0.3	0	24	0.3	0

KAMO	17	0.2	0	21	0.3	0	21	0.3	0
AMEREN	15	0.2	0	18	0.2	0	18	0.2	0
PAN_ENT	13	0.2	0	16	0.2	0	16	0.2	0
ENT_TDU	12	0.1	0	15	0.2	0	15	0.2	0
CELE	11	0.1	0	13	0.2	0	13	0.2	0
TVA									
NPPD	9	0.1	0	11	0.1	0	11	0.1	0
ALLIANT	8	0.1	0	10	0.1	0	10	0.1	0
COG	6	0.1	0						
MIDAM	6	0.1	0	7	0.1	0	7	0.1	0
SIKE	6	0.1	0	7	0.1	0	7	0.1	0
Totals	**8,003**	100.0	4,973	**7,992**	100.0	5,643	**8,107**	100.0	5,501

Destination Market Analysis	OKGE			
Type	EC			
Transmission Allocation	Pro Rata			
Period	Summer Peak			
Destination Market Price	40			
HHI	4,121		4,999	4,831
Change in HHI			878	710

Supplier	**Supplied**	**Pre Acquisition Market Share**	**HHI**	**Supplied**	**Post Acquisition Market Share**	**HHI Contribution**	**Supplied**	**W/ Mitigations Market Share**	**HHI Contribution**
	MW	**%**	**Contribution**	**MW**	**%**		**MW**	**%**	
OKGE	3,445	63.0	3,969	3,821	70.0	4,901	3,821	68.6	4,701
NRG	383	7.0	49	18	0.3	0	18	0.3	0
SCI									
SPS_OKGE	200	3.7	13						
INTR OGE	431	7.9	62	431	7.9	62	546	9.8	96
OMPA	174	3.2	10	174	3.2	10	174	3.1	10
Adjustment				-4	-0.1	0	-4	-0.1	0
CSW SPP	116	2.1	5	142	2.6	7	142	2.5	6
GRRD	104	1.9	4	127	2.3	5	127	2.3	5
WR	94	1.7	3	115	2.1	4	115	2.1	4
ENT	60	1.1	1	73	1.3	2	73	1.3	2
AECI	56	1.0	1	68	1.2	2	68	1.2	1
WEFA	45	0.8	1	55	1.0	1	55	1.0	1
EDE	38	0.7	0	46	0.8	1	46	0.8	1
CALPINE	37	0.7	0	45	0.8	1	45	0.8	1
UTILICOR	29	0.5	0	35	0.6	0	35	0.6	0

KCPL	27	0.5	0	33	0.6	0	33	0.6	0
EXELON	26	0.5	0	32	0.6	0	32	0.6	0
AMEREN	21	0.4	0	26	0.5	0	26	0.5	0
SWEPA	20	0.4	0	24	0.4	0	24	0.4	0
CELE	18	0.3	0	22	0.4	0	22	0.4	0
KAMO	18	0.3	0	22	0.4	0	22	0.4	0
PAN_ENT	17	0.3	0	21	0.4	0	21	0.4	0
ENT_TDU	15	0.3	0	18	0.3	0	18	0.3	0
TVA									
NPPD	11	0.2	0	13	0.2	0	13	0.2	0
ALLIANT	10	0.2	0	12	0.2	0	12	0.2	0
DYNERGY	10	0.2	0	12	0.2	0	12	0.2	0
OC_ENT	9	0.2	0	11	0.2	0	11	0.2	0
COG	7	0.1	0	9	0.2	0	9	0.2	0
DUKE	7	0.1	0	9	0.2	0	9	0.2	0
MIDAM	7	0.1	0	9	0.2	0	9	0.2	0
MOB_ENT	6	0.1	0	7	0.1	0	7	0.1	0
SIKE	6	0.1	0	7	0.1	0	7	0.1	0
WILL	6	0.1	0	7	0.1	0	7	0.1	0
DRI	5	0.1	0	6	0.1	0	6	0.1	0
SOCO_ENT	5	0.1	0	6	0.1	0	6	0.1	0
TECO	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**5,468**	100.0	4,121	**5,458**	100.0	4,999	**5,573**	100.0	4,831

Destination Market Analysis	OKGE
Type	EC
Transmission Allocation	Pro Rata
Period	Summer Off Peak
Destination Market Price	35

	Pre Acquisition	Post Acquisition	W/ Mitigations
HHI	3,638	4,554	4,391
Change in HHI		916	753

Supplier	**Pre Acquisition**			**Post Acquisition**			**W/ Mitigations**		
	Supplied MW	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	2,858	58.7	3,448	3,234	66.6	4,432	3,234	65.0	4,229
NRG	384	7.9	62	19	0.4	0	19	0.4	0
SCI									
SPS_OKGE	200	4.1	17						
INTR OGE	431	8.9	78	431	8.9	79	546	11.0	121
OMPA	157	3.2	10	157	3.2	10	157	3.2	10
Adjustment				-4	-0.1	0	-4	-0.1	0
CSW SPP	133	2.7	7	162	3.3	11	162	3.3	11
WR	91	1.9	3	111	2.3	5	111	2.2	5
GRRD	86	1.8	3	105	2.2	5	105	2.1	4
ENT	61	1.3	2	74	1.5	2	74	1.5	2
AECI	58	1.2	1	71	1.5	2	71	1.4	2
WEFA	46	0.9	1	56	1.2	1	56	1.1	1
EDE	45	0.9	1	55	1.1	1	55	1.1	1
CALPINE	38	0.8	1	46	0.9	1	46	0.9	1
UTILICOR	37	0.8	1	45	0.9	1	45	0.9	1
KCPL	34	0.7	0	41	0.8	1	41	0.8	1

EXELON	27	0.6	0	33	0.7	0	33	0.7	0
AMEREN	22	0.5	0	27	0.6	0	27	0.5	0
KAMO	22	0.5	0	27	0.6	0	27	0.5	0
PAN_ENT	17	0.3	0	21	0.4	0	21	0.4	0
TVA									
CELE	14	0.3	0	17	0.3	0	17	0.3	0
ENT_TDU	14	0.3	0	17	0.3	0	17	0.3	0
NPPD	13	0.3	0	16	0.3	0	16	0.3	0
ALLIANT	12	0.2	0	15	0.3	0	15	0.3	0
DYNERGY	11	0.2	0	13	0.3	0	13	0.3	0
MIDAM	8	0.2	0	10	0.2	0	10	0.2	0
COG	7	0.1	0	9	0.2	0	9	0.2	0
DUKE	7	0.1	0	9	0.2	0	9	0.2	0
SIKE	7	0.1	0	9	0.2	0	9	0.2	0
MOB_ENT	6	0.1	0	7	0.1	0	7	0.1	0
WILL	6	0.1	0	7	0.1	0	7	0.1	0
DRI	5	0.1	0	6	0.1	0	6	0.1	0
SOCO_ENT	5	0.1	0	6	0.1	0	6	0.1	0
TECO	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**4,867**	100.0	3,638	**4,858**	100.0	4,554	**4,973**	100.0	4,391

Destination Market	OKGE								
Analysis Type	EC								
Transmission Allocation	Pro Rata								
Period	Winter Super Peak								
Destination Market Price		40							
HHI		3,283			3,932			3,932	
Change in HHI					648			648	

	Pre Acquisition			Post Acquisition			W/ Mitigations		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	3,445	54.5	2,975	3,821	60.5	3,662	3,821	60.5	3,662
NRG	384	6.1	37	18	0.3	0	18	0.3	0
SCI									
SPS_OKGE	200	3.2	10						
INTR OGE	960	15.2	231	960	15.2	231	960	15.2	231
OMPA	174	2.8	8	174	2.8	8	174	2.8	8
CSW SPP	165	2.6	7	192	3.0	9	192	3.0	9
GRRD	111	1.8	3	129	2.0	4	129	2.0	4
WR	104	1.6	3	121	1.9	4	121	1.9	4
ENT	103	1.6	3	120	1.9	4	120	1.9	4
AECI	100	1.6	3	117	1.9	3	117	1.9	3
EDE	62	1.0	1	72	1.1	1	72	1.1	1
SWEPA	59	0.9	1	69	1.1	1	69	1.1	1
CALPINE	51	0.8	1	59	0.9	1	59	0.9	1
WEFA	48	0.8	1	56	0.9	1	56	0.9	1
KCPL	39	0.6	0	45	0.7	1	45	0.7	1
EXELON	37	0.6	0	43	0.7	0	43	0.7	0
ENT_TDU	26	0.4	0	30	0.5	0	30	0.5	0
PAN_ENT	26	0.4	0	30	0.5	0	30	0.5	0
CELE	25	0.4	0	29	0.5	0	29	0.5	0
UTILICOR	24	0.4	0	28	0.4	0	28	0.4	0

KAMO	19	0.3	0	22	0.3	0	22	0.3	0
SIKE	17	0.3	0	20	0.3	0	20	0.3	0
TVA									
DYNERGY	14	0.2	0	16	0.3	0	16	0.3	0
NPPD	13	0.2	0	15	0.2	0	15	0.2	0
COG	12	0.2	0	14	0.2	0	14	0.2	0
MIDAM	12	0.2	0	14	0.2	0	14	0.2	0
ALLIANT	11	0.2	0	13	0.2	0	13	0.2	0
DUKE	10	0.2	0	12	0.2	0	12	0.2	0
WILL	10	0.2	0	12	0.2	0	12	0.2	0
MOB_ENT	9	0.1	0	10	0.2	0	10	0.2	0
DRI	8	0.1	0	9	0.1	0	9	0.1	0
SOCO_ENT	8	0.1	0	9	0.1	0	9	0.1	0
TECO	8	0.1	0	9	0.1	0	9	0.1	0
KMI	6	0.1	0	7	0.1	0	7	0.1	0
PGE	6	0.1	0	7	0.1	0	7	0.1	0
KACY	5	0.1	0	6	0.1	0	6	0.1	0
LES	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**6,316**	100.0	3,283	**6,314**	100.0	3,932	**6,314**	100.0	3,932

Destination Market Analysis	OKGE								
Type	EC								
Transmission Allocation	Pro Rata								
Period	Winter Peak								
Destination Market Price	32								
HHI	2,895				3,549			3,549	
Change in HHI					655			655	

Supplier	**Supplied MW**	**Pre Acquisition Market Share %**	**HHI Contribution**	**Supplied MW**	**Post Acquisition Market Share %**	**HHI Contribution**	**Supplied MW**	**W/ Mitigations Market Share %**	**HHI Contribution**
OKGE	2,885	50.1	2,515	3,261	56.7	3,213	3,261	56.7	3,213
NRG	384	6.7	45	18	0.3	0	18	0.3	0
SCI									
SPS_OKGE	200	3.5	12						
INTR OGE	960	16.7	278	960	16.7	278	960	16.7	278
OMPA	170	3.0	9	170	3.0	9	170	3.0	9
ENT	193	3.4	11	225	3.9	15	225	3.9	15
Adjustment				-2	0.0	0	-2		
CSW SPP	190	3.3	11	222	3.9	15	222	3.9	15
GRRD	112	1.9	4	131	2.3	5	131	2.3	5
WR	105	1.8	3	122	2.1	4	122	2.1	4
KCPL	65	1.1	1	76	1.3	2	76	1.3	2
SWEPA	58	1.0	1	68	1.2	1	68	1.2	1
EDE	56	1.0	1	65	1.1	1	65	1.1	1
ENT_TDU	51	0.9	1	59	1.0	1	59	1.0	1
WEFA	48	0.8	1	56	1.0	1	56	1.0	1
AECI	39	0.7	0	45	0.8	1	45	0.8	1
CALPINE	39	0.7	0	45	0.8	1	45	0.8	1
EXELON	28	0.5	0	33	0.6	0	33	0.6	0

TVA									
CELE	22	0.4	0	26	0.5	0	26	0.5	0
KAMO	20	0.3	0	23	0.4	0	23	0.4	0
NPPD	17	0.3	0	20	0.3	0	20	0.3	0
MIDAM	16	0.3	0	19	0.3	0	19	0.3	0
SIKE	16	0.3	0	19	0.3	0	19	0.3	0
ALLIANT	13	0.2	0	15	0.3	0	15	0.3	0
DRI	13	0.2	0	15	0.3	0	15	0.3	0
WILL	10	0.2	0	12	0.2	0	12	0.2	0
KACY	7	0.1	0	8	0.1	0	8	0.1	0
LAFA	7	0.1	0	8	0.1	0	8	0.1	0
AMEREN	6	0.1	0	7	0.1	0	7	0.1	0
LEPA	6	0.1	0	7	0.1	0	7	0.1	0
LES	6	0.1	0	7	0.1	0	7	0.1	0
UTILICOR	6	0.1	0	7	0.1	0	7	0.1	0
OPPD	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**5,753**	100.0	2,895	**5,753**	100.0	3,549	**5,753**	100.0	3,549

Destination Market Analysis	OKGE
Type	EC
Transmission Allocation	Pro Rata
Period	Winter Peak
Destination Market Price	15

HHI	5,400	5,400	5,400
Change in HHI			

	Pre Acquisition			Post Acquisition			W/ Mitigations		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	2,741	72.9	5,314	2,741	72.9	5,314	2,741	72.9	5,314
NRG	198	5.3	28	198	5.3	28	198	5.3	28
SCI									
SPS_OKGE									
OMPA	47	1.3	2	47	1.3	2	47	1.3	2
TVA									
EDE	191	5.1	26	191	5.1	26	191	5.1	26
ENT	126	3.4	11	126	3.4	11	126	3.4	11
KCPL	119	3.2	10	119	3.2	10	119	3.2	10
WR	72	1.9	4	72	1.9	4	72	1.9	4
WEFA	53	1.4	2	53	1.4	2	53	1.4	2
GRRD	38	1.0	1	38	1.0	1	38	1.0	1
AMEREN	28	0.7	1	28	0.7	1	28	0.7	1
KAMO	25	0.7	0	25	0.7	0	25	0.7	0
ENT_TDU	23	0.6	0	23	0.6	0	23	0.6	0
SIKE	21	0.6	0	21	0.6	0	21	0.6	0
FPL_WR	19	0.5	0	19	0.5	0	19	0.5	0
NPPD	15	0.4	0	15	0.4	0	15	0.4	0

KACY	14	0.4	0	14	0.4	0	14	0.4	0
LAFA	12	0.3	0	12	0.3	0	12	0.3	0
ALLIANT	6	0.2	0	6	0.2	0	6	0.2	0
ENRON	6	0.2	0	6	0.2	0	6	0.2	0
NPPD_TDU	6	0.2	0	6	0.2	0	6	0.2	0
	3,760	100.0	5,400	**3,760**	100.0	5,400	**3,760**	100.0	5,400

Destination Market	OKGE		
Analysis Type	EC		
Transmission Allocation	Pro Rata		
Period	Shoulder Super Peak		
Destination Market Price	40		
HHI	3,009	3,601	3,601
Change in HHI		592	592

	Pre Acquisition			**Post Acquisition**			**W/ Mitigations**		
Supplier	**Supplied**	**Market Share**	**HHI**	**Supplied**	**Market Share**	**HHI Contribution**	**Supplied**	**Market Share**	**HHI Contribution**
	MW	**%**	**Contribution**	**MW**	**%**		**MW**	**%**	
OKGE	2,744	51.6	2,667	3,039	57.4	3,294	3,039	57.4	3,294
NRG	306	5.8	33	20	0.4	0	20	0.4	0
SCI									
SPS_OKGE	200	3.8	14						
INTR OGE	856	16.1	260	856	16.2	261	856	16.2	261
OMPA	145	2.7	7	145	2.7	7	145	2.7	7
Adjustment				-5	-0.1	0	-5	-0.1	0
CSW SPP	181	3.4	12	211	4.0	16	211	4.0	16
ENT	101	1.9	4	118	2.2	5	118	2.2	5
WR	86	1.6	3	100	1.9	4	100	1.9	4
GRRD	82	1.5	2	96	1.8	3	96	1.8	3
AECI	66	1.2	2	77	1.5	2	77	1.5	2
CALPINE	54	1.0	1	63	1.2	1	63	1.2	1
CELE	43	0.8	1	50	0.9	1	50	0.9	1
EDE	42	0.8	1	49	0.9	1	49	0.9	1
EXELON	39	0.7	1	46	0.9	1	46	0.9	1
AMEREN	35	0.7	0	41	0.8	1	41	0.8	1
TVA									
SWEPA	34	0.6	0	40	0.8	1	40	0.8	1

UTILICOR	34	0.6	0	40	0.8	1	40	0.8	1
WEFA	31	0.6	0	36	0.7	0	36	0.7	0
KCPL	30	0.6	0	35	0.7	0	35	0.7	0
NPPD	25	0.5	0	29	0.5	0	29	0.5	0
PAN_ENT	25	0.5	0	29	0.5	0	29	0.5	0
ENT_TDU	23	0.4	0	27	0.5	0	27	0.5	0
MIDAM	19	0.4	0	22	0.4	0	22	0.4	0
KAMO	14	0.3	0	16	0.3	0	16	0.3	0
ALLIANT	12	0.2	0	14	0.3	0	14	0.3	0
COG	11	0.2	0	13	0.2	0	13	0.2	0
DRI	9	0.2	0	11	0.2	0	11	0.2	0
DUKE	9	0.2	0	11	0.2	0	11	0.2	0
WILL	9	0.2	0	11	0.2	0	11	0.2	0
MOB_ENT	8	0.2	0	9	0.2	0	9	0.2	0
SIKE	8	0.2	0	9	0.2	0	9	0.2	0
SOCO_ENT	8	0.2	0	9	0.2	0	9	0.2	0
TECO	7	0.1	0	8	0.2	0	8	0.2	0
KMI	6	0.1	0	7	0.1	0	7	0.1	0
PGE	6	0.1	0	7	0.1	0	7	0.1	0
KACY	5	0.1	0	6	0.1	0	6	0.1	0
	5,313	100.0	3,009	5,295	100.0	3,601	5,295	100.0	3,601

Destination Market	OKGE
Analysis Type	EC
Transmission Allocation	Pro Rata
Period	Shoulder Peak
Destination Market Price	35

	Pre Acquisition	Post Acquisition	W/ Mitigations
HHI	2,570	3,144	3,144
Change in HHI		574	574

	Pre Acquisition			Post Acquisition			W/ Mitigations		
Supplier	**Supplied**	**Market Share**	**HHI**	**Supplied**	**Market Share**	**HHI Contribution**	**Supplied**	**Market Share**	**HHI Contribution**
	MW	**%**	**Contribution**	**MW**	**%**		**MW**	**%**	
OKGE	2,285	46.7	2,184	2,580	52.8	2,784	2,580	52.8	2,784
NRG	302	6.2	38	16	0.3	0	16	0.3	0
SCI									
SPS_OKGE	200								
INTR OGE	856	17.5	306	856	17.5	306	856	17.5	306
OMPA	140	2.9	8	140	2.9	8	140	2.9	8
Adjustment				6	0.1	0	6	0.1	0
CSW SPP	175	3.6	13	204	4.2	17	204	4.2	17
ENT	108	2.2	5	126	2.6	7	126	2.6	7
WR	102	2.1	4	119	2.4	6	119	2.4	6
GRRD	79	1.6	3	92	1.9	4	92	1.9	4
AECI	65	1.3	2	76	1.6	2	76	1.6	2
CALPINE	50	1.0	1	58	1.2	1	58	1.2	1
EDE	44	0.9	1	51	1.0	1	51	1.0	1
UTILICOR	41	0.8	1	48	1.0	1	48	1.0	1
TVA									
KCPL	39	0.8	1	46	0.9	1	46	0.9	1
EXELON	38	0.8	1	44	0.9	1	44	0.9	1

AMEREN	36	0.7	1	42	0.9	1	42	0.9	1
SWEPA	36	0.7	1	42	0.9	1	42	0.9	1
WEFA	31	0.6	0	36	0.7	1	36	0.7	1
NPPD	27	0.6	0	32	0.7	0	32	0.7	0
CELE	25	0.5	0	29	0.6	0	29	0.6	0
ENT_TDU	25	0.5	0	29	0.6	0	29	0.6	0
PAN_ENT	25	0.5	0	29	0.6	0	29	0.6	0
MIDAM	21	0.4	0	25	0.5	0	25	0.5	0
DYNERGY	20	0.4	0	23	0.5	0	23	0.5	0
ALLIANT	13	0.3	0	15	0.3	0	15	0.3	0
KAMO	13	0.3	0	15	0.3	0	15	0.3	0
COG	11	0.2	0	13	0.3	0	13	0.3	0
DRI	10	0.2	0	12	0.2	0	12	0.2	0
DUKE	9	0.2	0	11	0.2	0	11	0.2	0
SIKE	9	0.2	0	11	0.2	0	11	0.2	0
WILL	9	0.2	0	11	0.2	0	11	0.2	0
MOB_ENT	8	0.2	0	9	0.2	0	9	0.2	0
SOCO_ENT	8	0.2	0	9	0.2	0	9	0.2	0
TECO	7	0.1	0	8	0.2	0	8	0.2	0
KACY	6	0.1	0	7	0.1	0	7	0.1	0
KMI	6	0.1	0	7	0.1	0	7	0.1	0
PGE	6	0.1	0	7	0.1	0	7	0.1	0
LEPA	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**4,890**	95.9	2,570	**4,890**	100.0	3,144	**4,890**	100.0	3,144

Destination Market	OKGE		
Analysis Type	EC		
Transmission Allocation	Pro Rata		
Period	Shoulder Off Peak		
Destination Market Price	35		
HHI	2,680	3,253	3,253
Change in HHI		573	573

	Pre Acquisition			**Post Acquisition**			**W/ Mitigations**		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	2,301	47.6	2,266	2,596	53.6	2,869	2,596	53.6	2,869
NRG	16	0.3	0	16	0.3	0	16	0.3	0
SCI									
SPS_OKGE	200	4.1	17						
INTR OGE	856	17.7	314	856	17.7	312	856	17.7	312
OMPA	46	1.0	1	46	0.9	1	46	0.9	1
ENT	235	4.9	24	235	4.8	24	235	4.8	24
Adjustment				13	0.3	0	13	0.3	0
CSW SPP	226	4.7	22	226	4.7	22	226	4.7	22
unk	178	3.7	14	83	1.7	3	83	1.7	3
WR	133	2.8	8	133	2.7	8	133	2.7	8
TVA									
KCPL	103	2.1	5	103	2.1	5	103	2.1	5
NPPD	75	1.6	2	75	1.5	2	75	1.5	2
GRRD	72	1.5	2	72	1.5	2	72	1.5	2
AMEREN	64	1.3	2	64	1.3	2	64	1.3	2
MIDAM	59	1.2	1	59	1.2	1	59	1.2	1
EDE	57	1.2	1	57	1.2	1	57	1.2	1

DYNERGY	41	0.8	1	41	0.8	1	41	0.8	1
ALLIANT	38	0.8	1	38	0.8	1	38	0.8	1
WEFA	33	0.7	0	33	0.7	0	33	0.7	0
KAMO	19	0.4	0	19	0.4	0	19	0.4	0
KACY	11	0.2	0	11	0.2	0	11	0.2	0
LAFA	10	0.2	0	10	0.2	0	10	0.2	0
SIKE	10	0.2	0	10	0.2	0	10	0.2	0
BREC	8	0.2	0	8	0.2	0	8	0.2	0
CIN	8	0.2	0	8	0.2	0	8	0.2	0
WAPA	8	0.2	0	8	0.2	0	8	0.2	0
ENT_TDU	7	0.1	0	7	0.1	0	7	0.1	0
LEPA	7	0.1	0	7	0.1	0	7	0.1	0
OPPD	7	0.1	0	7	0.1	0	7	0.1	0
LES	6	0.1	0	6	0.1	0	6	0.1	0
Totals	**4,834**	100.0	2,680	**4,847**	100.0	3,253	**4,847**	100.0	3,253

Appendix B – Market Share and HHI Analysis for Proposed Modified Regulatory Practices

Destination Market	OKGE		
Analysis Type	EC		
Transmission Allocation	Pro Rata		
Period	Highest Summer Super Peak		
Destination Market Price	200		
HHI	5,114	5,770	4,935
Change in HHI		656	-179

	Pre Acquisition			**Post Acquisition**			**W/ Modified Mitigations**		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	5,871	70.9	5,028	6,247	75.5	5,707	6,247	68.8	4,729
NRG	388	4.7	22	24	0.3	0	24	0.3	0
SCI									
SPS_OKGE	200	2.4	6						
INTR OGE	431	5.2	27	431	5.2	27	1,204	13.3	176
ONEOK	302	3.6	13	302	3.7	13	302	3.3	11
OMPA	258	3.1	10	258	3.1	10	258	2.8	8
Adjustment				-5	-0.1	0	37	0.4	0
CSW SPP	134	1.6	3	164	2.0	4	164	1.8	3
WR	101	1.2	1	123	1.5	2	123	1.4	2
ENT	98	1.2	1	120	1.5	2	120	1.3	2
GRRD	89	1.1	1	109	1.3	2	109	1.2	1
KMI	56	0.7	0	68	0.8	1	68	0.7	1
WEFA	52	0.6	0	63	0.8	1	63	0.7	0
AECI	46	0.6	0	56	0.7	0	56	0.6	0
EDE	37	0.4	0	45	0.5	0	45	0.5	0
CALPINE	24	0.3	0	29	0.4	0	29	0.3	0
UTILICOR	24	0.3	0	29	0.4	0	29	0.3	0
SWEPA	21	0.3	0	26	0.3	0	26	0.3	0
KCPL	18	0.2	0	22	0.3	0	22	0.2	0
EXELON	16	0.2	0	20	0.2	0	20	0.2	0

KAMO	15	0.2	0	18	0.2	0	18	0.2	0
AMEREN	13	0.2	0	16	0.2	0	16	0.2	0
ENT_TDU	13	0.2	0	16	0.2	0	16	0.2	0
CELE	12	0.1	0	15	0.2	0	15	0.2	0
DUKE	10	0.1	0	12	0.1	0	12	0.1	0
PAN_ENT	10	0.1	0	12	0.1	0	12	0.1	0
TVA									
DYNERGY	7	0.1	0	9	0.1	0	9	0.1	0
NPPD	7	0.1	0	9	0.1	0	9	0.1	0
ALLIANT	6	0.1	0	7	0.1	0	7	0.1	0
SIKE	6	0.1	0	6	0.1	0	6	0.1	0
LES	5	0.1	0	6	0.1	0	6	0.1	0
MIDAM	5	0.1	0	6	0.1	0	6	0.1	0
OC_ENT	5	0.1	0	6	0.1	0	6	0.1	0
Total	**8,280**	100.0	5,114	**8,269**	100.0	5,770	**9,084**	100.0	4,935

Destination Market	OKGE
Analysis Type	EC
Transmission Allocation	Pro Rata
Period	High Summer Super Peak
Destination Market Price	200

	Pre Acquisition	Post Acquisition	W/ Modified Mitigations
HHI	4,973	5,643	4,812
Change in HHI		670	-161

Supplier		**Pre Acquisition**			**Post Acquisition**			**W/ Modified Mitigations**	
	Supplied MW	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	5,591	69.9	4,881	5,967	74.7	5,574	5,967	67.8	4,590
NRG	380	4.7	23	14	0.2	0	14	0.2	0
SCI									
SPS_OKGE	200	2.5	6						
INTR OGE	431	5.4	29	431	5.4	29	1,204	13.7	187
ONEOK	302	3.8	14	302	3.8	14	302	3.4	12
OMPA	257	3.2	10	257	3.2	10	257	2.9	9
CSW SPP	141	1.8	3	172	2.2	5	214	2.4	6
GRRD	98	1.2	1	120	1.5	2	120	1.4	2
WR	98	1.2	1	120	1.5	2	120	1.4	2
ENT	91	1.1	1	111	1.4	2	111	1.3	2
WEFA	64	0.8	1	78	1.0	1	78	0.9	1
KMI	57	0.7	1	70	0.9	1	70	0.8	1
AECI	45	0.6	0	55	0.7	0	55	0.6	0
EDE	35	0.4	0	43	0.5	0	43	0.5	0
CALPINE	25	0.3	0	31	0.4	0	31	0.4	0
KCPL	24	0.3	0	29	0.4	0	29	0.3	0
SWEPA	21	0.3	0	26	0.3	0	26	0.3	0

EXELON	20	0.2	0	24	0.3	0	24	0.3	0
UTILICOR	20	0.2	0	24	0.3	0	24	0.3	0
KAMO	17	0.2	0	21	0.3	0	21	0.2	0
AMEREN	15	0.2	0	18	0.2	0	18	0.2	0
PAN_ENT	13	0.2	0	16	0.2	0	16	0.2	0
ENT_TDU	12	0.1	0	15	0.2	0	15	0.2	0
CELE	11	0.1	0	13	0.2	0	13	0.1	0
TVA									
NPPD	9	0.1	0	11	0.1	0	11	0.1	0
ALLIANT	8	0.1	0	10	0.1	0	10	0.1	0
COG	6	0.1	0						
MIDAM	6	0.1	0	7	0.1	0	7	0.1	0
SIKE	6	0.1	0	7	0.1	0	7	0.1	0
Totals	**8,003**	100.0	4,973	**7,992**	100.0	5,643	**8,807**	100.0	4,812

Destination Market Analysis	OKGE		
Type	EC		
Transmission Allocation	Pro Rata		
Period	Summer Peak		
Destination Market Price	40		
HHI	4,121	4,999	4,106
Change in HHI		878	-15

Supplier	**Pre Acquisition**			**Post Acquisition**			**W/ Modified Mitigations**		
	Supplied MW	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	3,445	63.0	3,969	3,821	70.0	4,901	3,821	60.9	3,710
NRG	383	7.0	49	18	0.3	0	18	0.3	0
SCI									
SPS_OKGE	200	3.7	13						
INTR OGE	431	7.9	62	431	7.9	62	1,204	19.2	368
OMPA	174	3.2	10	174	3.2	10	174	2.8	8
Adjustment				-4	-0.1	0	38	0.6	0
CSW SPP	116	2.1	5	142	2.6	7	142	2.3	5
GRRD	104	1.9	4	127	2.3	5	127	2.0	4
WR	94	1.7	3	115	2.1	4	115	1.8	3
ENT	60	1.1	1	73	1.3	2	73	1.2	1
AECI	56	1.0	1	68	1.2	2	68	1.1	1
WEFA	45	0.8	1	55	1.0	1	55	0.9	1
EDE	38	0.7	0	46	0.8	1	46	0.7	1
CALPINE	37	0.7	0	45	0.8	1	45	0.7	1
UTILICOR	29	0.5	0	35	0.6	0	35	0.6	0
KCPL	27	0.5	0	33	0.6	0	33	0.5	0

EXELON	26	0.5	0	32	0.6	0	32	0.5	0
AMEREN	21	0.4	0	26	0.5	0	26	0.4	0
SWEPA	20	0.4	0	24	0.4	0	24	0.4	0
CELE	18	0.3	0	22	0.4	0	22	0.4	0
KAMO	18	0.3	0	22	0.4	0	22	0.4	0
PAN_ENT	17	0.3	0	21	0.4	0	21	0.3	0
ENT_TDU	15	0.3	0	18	0.3	0	18	0.3	0
TVA									
NPPD	11	0.2	0	13	0.2	0	13	0.2	0
ALLIANT	10	0.2	0	12	0.2	0	12	0.2	0
DYNERGY	10	0.2	0	12	0.2	0	12	0.2	0
OC_ENT	9	0.2	0	11	0.2	0	11	0.2	0
COG	7	0.1	0	9	0.2	0	9	0.1	0
DUKE	7	0.1	0	9	0.2	0	9	0.1	0
MIDAM	7	0.1	0	9	0.2	0	9	0.1	0
MOB_ENT	6	0.1	0	7	0.1	0	7	0.1	0
SIKE	6	0.1	0	7	0.1	0	7	0.1	0
WILL	6	0.1	0	7	0.1	0	7	0.1	0
DRI	5	0.1	0	6	0.1	0	6	0.1	0
SOCO_ENT	5	0.1	0	6	0.1	0	6	0.1	0
TECO	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**5,468**	100.0	4,121	**5,458**	100.0	4,999	**6,273**	100.0	4,106

Period		Summer Off Peak							
Destination Market Price		35							
HHI		3,638			4,554			3,737	
Change in HHI					916			99	

	Pre Acquisition			Post Acquisition			W/ Modified Mitigations		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	2,858	58.7	3,448	3,234	66.6	4,432	3,234	57.0	3,250
NRG	384	7.9	62	19	0.4	0	19	0.3	0
SCI									
SPS_OKGE	200	4.1	17						
INTR OGE	431	8.9	78	431	8.9	79	1,204	21.2	450
OMPA	157	3.2	10	157	3.2	10	157	2.8	8
Adjustment				-4	-0.1	0	-4	-0.1	0
CSW SPP	133	2.7	7	162	3.3	11	204	3.6	13
WR	91	1.9	3	111	2.3	5	111	2.0	4
GRRD	86	1.8	3	105	2.2	5	105	1.9	3
ENT	61	1.3	2	74	1.5	2	74	1.3	2
AECI	58	1.2	1	71	1.5	2	71	1.3	2
WEFA	46	0.9	1	56	1.2	1	56	1.0	1
EDE	45	0.9	1	55	1.1	1	55	1.0	1
CALPINE	38	0.8	1	46	0.9	1	46	0.8	1
UTILICOR	37	0.8	1	45	0.9	1	45	0.8	1
KCPL	34	0.7	0	41	0.8	1	41	0.7	1
EXELON	27	0.6	0	33	0.7	0	33	0.6	0
AMEREN	22	0.5	0	27	0.6	0	27	0.5	0
KAMO	22	0.5	0	27	0.6	0	27	0.5	0
PAN_ENT	17	0.3	0	21	0.4	0	21	0.4	0

TVA									
CELE	14	0.3	0	17	0.3	0	17	0.3	0
ENT_TDU	14	0.3	0	17	0.3	0	17	0.3	0
NPPD	13	0.3	0	16	0.3	0	16	0.3	0
ALLIANT	12	0.2	0	15	0.3	0	15	0.3	0
DYNERGY	11	0.2	0	13	0.3	0	13	0.2	0
MIDAM	8	0.2	0	10	0.2	0	10	0.2	0
COG	7	0.1	0	9	0.2	0	9	0.2	0
DUKE	7	0.1	0	9	0.2	0	9	0.2	0
SIKE	7	0.1	0	9	0.2	0	9	0.2	0
MOB_ENT	6	0.1	0	7	0.1	0	7	0.1	0
WILL	6	0.1	0	7	0.1	0	7	0.1	0
DRI	5	0.1	0	6	0.1	0	6	0.1	0
SOCO_ENT	5	0.1	0	6	0.1	0	6	0.1	0
TECO	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**4,867**	100.0	3,638	**4,858**	100.0	4,554	**5,673**	100.0	3,737

Destination Market	OKGE		
Analysis Type	EC		
Transmission Allocation	Pro Rata		
Period	Winter Super Peak		
Destination Market Price	40		
HHI	3,283	3,932	3,311
Change in HHI		648	28

	Pre Acquisition			Post Acquisition			W/ Modified Mitigations		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	3,445	54.5	2,975	3,821	60.5	3,662	3,821	53.8	2,893
NRG	384	6.1	37	18	0.3	0	18	0.3	0
SCI									
SPS_OKGE	200	3.2	10						
INTR OGE	960	15.2	231	960	15.2	231	1,204	16.9	287
OMPA	174	2.8	8	174	2.8	8	174	2.4	6
CSW SPP	165	2.6	7	192	3.0	9	738	10.4	108
GRRD	111	1.8	3	129	2.0	4	129	1.8	3
WR	104	1.6	3	121	1.9	4	121	1.7	3
ENT	103	1.6	3	120	1.9	4	120	1.7	3
AECI	100	1.6	3	117	1.9	3	117	1.6	3
EDE	62	1.0	1	72	1.1	1	72	1.0	1
SWEPA	59	0.9	1	69	1.1	1	69	1.0	1
CALPINE	51	0.8	1	59	0.9	1	59	0.8	1
WEFA	48	0.8	1	56	0.9	1	56	0.8	1
KCPL	39	0.6	0	45	0.7	1	45	0.6	0
EXELON	37	0.6	0	43	0.7	0	43	0.6	0
ENT_TDU	26	0.4	0	30	0.5	0	30	0.4	0
PAN_ENT	26	0.4	0	30	0.5	0	30	0.4	0

CELE	25	0.4	0	29	0.5	0	29	0.4	0
UTILICOR	24	0.4	0	28	0.4	0	28	0.4	0
KAMO	19	0.3	0	22	0.3	0	22	0.3	0
SIKE	17	0.3	0	20	0.3	0	20	0.3	0
TVA									
DYNERGY	14	0.2	0	16	0.3	0	16	0.2	0
NPPD	13	0.2	0	15	0.2	0	15	0.2	0
COG	12	0.2	0	14	0.2	0	14	0.2	0
MIDAM	12	0.2	0	14	0.2	0	14	0.2	0
ALLIANT	11	0.2	0	13	0.2	0	13	0.2	0
DUKE	10	0.2	0	12	0.2	0	12	0.2	0
WILL	10	0.2	0	12	0.2	0	12	0.2	0
MOB_ENT	9	0.1	0	10	0.2	0	10	0.1	0
DRI	8	0.1	0	9	0.1	0	9	0.1	0
SOCO_ENT	8	0.1	0	9	0.1	0	9	0.1	0
TECO	8	0.1	0	9	0.1	0	9	0.1	0
KMI	6	0.1	0	7	0.1	0	7	0.1	0
PGE	6	0.1	0	7	0.1	0	7	0.1	0
KACY	5	0.1	0	6	0.1	0	6	0.1	0
LES	5	0.1	0	6	0.1	0	6	0.1	0

Destination Market Analysis	OKGE		
Type	EC		
Transmission Allocation	Pro Rata		
Period	Winter Peak		
Destination Market Price	32		
HHI	2,895	3,549	2,993
Change in HHI		655	99

	Pre Acquisition			Post Acquisition			W/ Modified Mitigations		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	2,885	50.1	2,515	3,261	56.7	3,213	3,261	49.8	2,484
NRG	384	6.7	45	18	0.3	0	18	0.3	0
SCI									
SPS_OKGE	200	3.5	12						
INTR OGE	960	16.7	278	960	16.7	278	1,204	18.4	339
OMPA	170	3.0	9	170	3.0	9	170	2.6	7
ENT	193	3.4	11	225	3.9	15	225	3.4	12
Adjustment				-2	0.0	0	-2		
CSW SPP	190	3.3	11	222	3.9	15	768	11.7	138
GRRD	112	1.9	4	131	2.3	5	131	2.0	4
WR	105	1.8	3	122	2.1	4	122	1.9	3
KCPL	65	1.1	1	76	1.3	2	76	1.2	1
SWEPA	58	1.0	1	68	1.2	1	68	1.0	1
EDE	56	1.0	1	65	1.1	1	65	1.0	1
ENT_TDU	51	0.9	1	59	1.0	1	59	0.9	1
WEFA	48	0.8	1	56	1.0	1	56	0.9	1
AECI	39	0.7	0	45	0.8	1	45	0.7	0
CALPINE	39	0.7	0	45	0.8	1	45	0.7	0

EXELON	28	0.5	0	33	0.6	0	33	0.5	0
TVA									
CELE	22	0.4	0	26	0.5	0	26	0.4	0
KAMO	20	0.3	0	23	0.4	0	23	0.4	0
NPPD	17	0.3	0	20	0.3	0	20	0.3	0
MIDAM	16	0.3	0	19	0.3	0	19	0.3	0
SIKE	16	0.3	0	19	0.3	0	19	0.3	0
ALLIANT	13	0.2	0	15	0.3	0	15	0.2	0
DRI	13	0.2	0	15	0.3	0	15	0.2	0
WILL	10	0.2	0	12	0.2	0	12	0.2	0
KACY	7	0.1	0	8	0.1	0	8	0.1	0
LAFA	7	0.1	0	8	0.1	0	8	0.1	0
AMEREN	6	0.1	0	7	0.1	0	7	0.1	0
LEPA	6	0.1	0	7	0.1	0	7	0.1	0
LES	6	0.1	0	7	0.1	0	7	0.1	0
UTILICOR	6	0.1	0	7	0.1	0	7	0.1	0
OPPD	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**5,753**	100.0	2,895	**5,753**	100.0	3,549	**6,543**	100.0	2,993

Destination Market	OKGE								
Analysis Type	EC								
Transmission Allocation	Pro Rata								
Period	Shoulder Super Peak								
Destination Market Price		40							
HHI		3,009			3,601			3,024	
Change in HHI					592			15	

Supplier	**Pre Acquisition** Supplied MW	Market Share %	HHI Contribution	**Post Acquisition** Supplied MW	Market Share %	HHI Contribution	**W/ Modified Mitigations** Supplied MW	Market Share %	HHI Contribution
OKGE	2,744	51.6	2,667	3,039	57.4	3,294	3,039	50.0	2,495
NRG	306	5.8	33	20	0.4	0	20	0.3	0
SCI									
SPS_OKGE	200	3.8	14						
INTR OGE	856	16.1	260	856	16.2	261	1,204	19.8	392
OMPA	145	2.7	7	145	2.7	7	145	2.4	6
Adjustment				-5	-0.1	0	-5	-0.1	0
CSW SPP	181	3.4	12	211	4.0	16	652	10.7	115
ENT	101	1.9	4	118	2.2	5	118	1.9	4
WR	86	1.6	3	100	1.9	4	100	1.6	3
GRRD	82	1.5	2	96	1.8	3	96	1.6	2
AECI	66	1.2	2	77	1.5	2	77	1.3	2
CALPINE	54	1.0	1	63	1.2	1	63	1.0	1
CELE	43	0.8	1	50	0.9	1	50	0.8	1
EDE	42	0.8	1	49	0.9	1	49	0.8	1
EXELON	39	0.7	1	46	0.9	1	46	0.8	1
AMEREN	35	0.7	0	41	0.8	1	41	0.7	0
TVA									
SWEPA	34	0.6	0	40	0.8	1	40	0.7	0

UTILICOR	34	0.6	0	40	0.8	1	40	0.7	0
WEFA	31	0.6	0	36	0.7	0	36	0.6	0
KCPL	30	0.6	0	35	0.7	0	35	0.6	0
NPPD	25	0.5	0	29	0.5	0	29	0.5	0
PAN_ENT	25	0.5	0	29	0.5	0	29	0.5	0
ENT_TDU	23	0.4	0	27	0.5	0	27	0.4	0
MIDAM	19	0.4	0	22	0.4	0	22	0.4	0
KAMO	14	0.3	0	16	0.3	0	16	0.3	0
ALLIANT	12	0.2	0	14	0.3	0	14	0.2	0
COG	11	0.2	0	13	0.2	0	13	0.2	0
DRI	9	0.2	0	11	0.2	0	11	0.2	0
DUKE	9	0.2	0	11	0.2	0	11	0.2	0
WILL	9	0.2	0	11	0.2	0	11	0.2	0
MOB_ENT	8	0.2	0	9	0.2	0	9	0.1	0
SIKE	8	0.2	0	9	0.2	0	9	0.1	0
SOCO_ENT	8	0.2	0	9	0.2	0	9	0.1	0
TECO	7	0.1	0	8	0.2	0	8	0.1	0
KMI	6	0.1	0	7	0.1	0	7	0.1	0
PGE	6	0.1	0	7	0.1	0	7	0.1	0
KACY	5	0.1	0	6	0.1	0	6	0.1	0
	5,313	100.0	3,009	5,295	100.0	3,601	6,084	100.0	3,024

Destination Market	OKGE								
Analysis Type	EC								
Transmission Allocation	Pro Rata								
Period	Shoulder Peak								
Destination Market Price		35							
HHI		2,570			3,144			2,669	
Change in HHI					574			99	

	Pre Acquisition			**Post Acquisition**			**W/ Modified Mitigations**		
Supplier	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**	**Supplied MW**	**Market Share %**	**HHI Contribution**
OKGE	2,285	46.7	2,184	2,580	52.8	2,784	2,580	45.4	2,063
NRG	302	6.2	38	16	0.3	0	16	0.3	0
SCI									
SPS_OKGE	200								
INTR OGE	856	17.5	306	856	17.5	306	1,204	21.2	449
OMPA	140	2.9	8	140	2.9	8	140	2.5	6
Adjustment				6	0.1	0	6	0.1	0
CSW SPP	175	3.6	13	204	4.2	17	646	11.4	129
ENT	108	2.2	5	126	2.6	7	126	2.2	5
WR	102	2.1	4	119	2.4	6	119	2.1	4
GRRD	79	1.6	3	92	1.9	4	92	1.6	3
AECI	65	1.3	2	76	1.6	2	76	1.3	2
CALPINE	50	1.0	1	58	1.2	1	58	1.0	1
EDE	44	0.9	1	51	1.0	1	51	0.9	1
UTILICOR	41	0.8	1	48	1.0	1	48	0.8	1
TVA									
KCPL	39	0.8	1	46	0.9	1	46	0.8	1
EXELON	38	0.8	1	44	0.9	1	44	0.8	1
AMEREN	36	0.7	1	42	0.9	1	42	0.7	1

SWEPA	36	0.7	1	42	0.9	1	42	0.7	1
WEFA	31	0.6	0	36	0.7	1	36	0.6	0
NPPD	27	0.6	0	32	0.7	0	32	0.6	0
CELE	25	0.5	0	29	0.6	0	29	0.5	0
ENT_TDU	25	0.5	0	29	0.6	0	29	0.5	0
PAN_ENT	25	0.5	0	29	0.6	0	29	0.5	0
MIDAM	21	0.4	0	25	0.5	0	25	0.4	0
DYNERGY	20	0.4	0	23	0.5	0	23	0.4	0
ALLIANT	13	0.3	0	15	0.3	0	15	0.3	0
KAMO	13	0.3	0	15	0.3	0	15	0.3	0
COG	11	0.2	0	13	0.3	0	13	0.2	0
DRI	10	0.2	0	12	0.2	0	12	0.2	0
DUKE	9	0.2	0	11	0.2	0	11	0.2	0
SIKE	9	0.2	0	11	0.2	0	11	0.2	0
WILL	9	0.2	0	11	0.2	0	11	0.2	0
MOB_ENT	8	0.2	0	9	0.2	0	9	0.2	0
SOCO_ENT	8	0.2	0	9	0.2	0	9	0.2	0
TECO	7	0.1	0	8	0.2	0	8	0.1	0
KACY	6	0.1	0	7	0.1	0	7	0.1	0
KMI	6	0.1	0	7	0.1	0	7	0.1	0
PGE	6	0.1	0	7	0.1	0	7	0.1	0
LEPA	5	0.1	0	6	0.1	0	6	0.1	0
Totals	**4,890**	95.9	2,570	**4,890**	100.0	3,144	**5,680**	100.0	2,669