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Market Power and Regulatory Failure in the Montana Wholesale Electricity Market

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MARKET POWER AND REGULATORY FAILURES IN THE MONTANA WHOLESALE ELECTRICITY MARKET

By

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All errors contained in this work are my own. Future readers are encouraged to contact me at ross.keogh@gmail.com.

II Table of Contents

MARKET POWER AND REGULATORY FAILURES IN THE MONTANA WHOLESALE ELECTRICITY MARKET

I Acknowledgments ... ii

II Table of Contents ... iii

III Table of Figures ... v

IV List of Acronyms ... vii

V Introduction ... vii

VI A Note on Units in the Electrical Industry ... ix

1: History of the Montana Electrical Market ... 1

1.1 Building the Montana Power Company (1884-1940) ... 1
1.2 Federal Action Spurs Rural Electrification and More Dams (1940-1970) ... 3
1.3 Coal (1970-1992) ... 6
1.4 Montana Power Company Exits (1992-2001) ... 8
1.5 NorthWestern Energy and the Addition of Wind and Gas (2001 -2010) ... 12
1.6 Conclusion ... 17

2: The Regulation of Market Power in Electrical Markets ... 19

2.1 Natural Monopoly Regulation ... 19
2.2 Open Access ... 21
2.3 The FERC's Regulation of Horizontal Market Power ... 26
2.4 Montana Case Study ... 29
2.5 Critique of the FERC's Review Process ... 32
2.6 Conclusion ... 36

3: Modeling and Detecting Market Power ... 37

3.1 Market Power Theory and Structure ... 37
3.2 Economic Literature Review ... 40
Cournot Model ... 42

Supply Function Equilibrium Model ... 45
Modeling Implications for Detecting Market Power ... 46
3.3 Approaches to Using Game Theory for Regulating Market Power ... 49
3.4 Market Structure and Changes in the Pacific NorthWest ... 53
3.5 Conclusion ... 56

4: Montana Electrical Industry Structure ... 57

4.1 Aggregate Price and Demand ... 57
4.2 Market Organization and Transmission ... 64
4.3 Wholesale Data Analysis ... 69
4.4 Montana Generation Classification ... 79
4.5 NorthWestern Energy's Position ... 82
4.6 Analysis, Montana Model and Lerner Index Calculation ... 88
4.7 Conclusion ... 92

5: Conclusion ... 93

5.1 Deregulation was a Costly Failure ... 93
5.2 Market Power Questions Linger ... 93

References ... 95

Appendix I, FERC Dataset Import Methodology ... 101

Appendix II, Montana Table of Generating Capacity ... 102

Appendix III, Supply Curve Estimation ... 105

III Table of Figures

Table 1.1.1 Hydroelectric Capacity of the MPC (1941) 3

Table 1.3.1 Ownership of Colstrip Unit's 3 and 4 (1986) 7

Table 1.3.2 Qualifying Facility Plant Development (2010) 8

Table 1.3.3 PPL's Assets (2010) 10

Table 1.3.4 Industrial Loads Served by PPL Montana (2010) 12

Figure 1.5.1 Montana Historical Capacity Growth (2010) 14

Figure 2.2.1 Map of Organized Markets in North America (2009) 24

Figure 2.2.1 Illustrative Generator Cost Structure ($/MWH) 26

Table 2.4.1 Comparison of PPL's Concentration Calculation 30

Equitation 2.5.1 Pivotal Supplier Equation 33

Equation 3.2.1 Cournot Equilibrium 43

Equation 3.2.2 Supply Function Equilibrium Mark-up Rule 45

Equation 3.3.3 Lerner Index 48

Figure 3.4.1 PacifiCorp's Proposed Resource Stack (PacifiCorp, 2011) 54

Figure 4.1.1 Montana Demand by Supplier Class, aMW (2004) 58

Figure 4.1.2 Montana Historical Demand by Supplier Class, aMW 59

Figure 4.1.3 Montana Historical Retail Price by Supplier Class, $/MWh 59

Figure 4.1.4 Historical Retail Price, Investor Owned Utilities, $/MWh 60

Figure 4.1.5 MT to ID Historical Retail Price Electrical Comparison, $/MWh 62

Figure 4.1.6 NorthWestern Energy Historical Premium to Idaho Power, $/MWh 62

Figure 4.2.1 Cost of Transmission as a Function of Utilization, $/MWh 66

Figure 4.2.2 Transmission Topology (2010) 67

Figure 4.2.4 Montana to Northwest Path Duration Chart (WECC, 2011) 68

Figure 4.3.1 Quarterly Purchases by NorthWestern Energy, aMW 71

Figure 4.3.2 Quarterly Purchases by NorthWestern Energy within their BAA, aMW 72

Figure 4.3.3 Location of PPL's Sales other than NorthWestern Energy, aMW 73

Figure 4.3.4 Historical NorthWestern Energy Price Premium from PPL, $/MWh 74

Figure 4.3.5 Historical PPL and Fringe Price to NorthWestern Energy, $/MWh 75

Figure 4.3.6 Fringe Premium Compared to MID-C, $/MWh 75

Figure 4.3.7 MID-C Prices and Quantities, Short-Term (ST) and Long-Term (LT) transactions 76

Figure 4.3.8 PPL's Historical Quantity and Revenue 77

Figure 4.4.1 Location of Montana Electrical Capacity by Balancing Authority Area (2010) 80

Table 4.4.1 Control of Montana Electrical Capacity 81

Figure 4.4.2 Facility Capacity Break-down by Fuel Source (2010)... 81

Figure 4.5.1 Historical Composition of NorthWestern Energy's Electrical Retail Price 83

Figure 4.5.2 Historical Composition of NorthWestern Energy's Electrical Retail Quantity.................. 83

Figure 4.5.3 Composition of NorthWestern Energy's Electrical Retail Price (2011) 84

Table 4.5.1 NorthWestern Energy's Supply Stack (2008)... 85

Figure 4.5.4 NorthWestern Energy's Purchase and Sale activity, Short-Term (ST), aMW 86

Figure 4.5.5 NorthWestern Energy's High-Load and Light-Load Resource Stack (2008) 87

Equation 4.6.1 PPL's Profit Equation 89

Equation 4.6.2 PPL's First Order Conditions.. 89

Table 4.6.1 Monopoly Model, with Competitive Fringe 90

Table 4.6.2 Factor Influences 90

Figure 4.6.1 PPL Lerner Index, Function of the Seven Year Contract 92

Figure A3.1.1, Estimation Results Fringe Supply Curve 105

IV List of Acronyms

FERC: Federal Energy Regulatory Commission
HHI: Herfindahl-Hirschman Index
kV: Kilovolt
kWh: Kilowatt hour
MPC: Montana Power Company
Montana PSC: Montana Public Service Commission
MW: Megawatt
MWh: Megawatt hour
PPL: PPL Corporation

V Introduction

The enactment of Senate Bill 390 by the Montana Legislature in 1997 paved the way for a fundamental restructuring of Montana's electrical industry. Within two years, the state's dominant electrical supplier - the Montana Power Company ("MPC") – had sold off its rate-based generation assets to PPL Corporation ("PPL"). With the utility's generation assets severed, retail suppliers in Montana had to procure electricity from an electrical market dominated by a single firm, PPL, which at the time owned 44% of the state's electrical capacity. This sale effectively removed Montana's state regulatory agency – the Montana Public Service Commission ("Montana PSC") – from regulating market outcomes, which had no jurisdiction over the wholesale electrical market. The task of regulating the wholesale power market fell to the Federal Energy Regulatory Commission ("FERC"). This paper will investigate the FERC's regulation of the wholesale power industry in Montana, and whether it provided an effective deterrent to the exercise of market power by PPL.

Prior to the deregulation of the Montana electrical industry, there was little significance to the regulatory questions and impacts explored in this thesis. MPC had developed as a natural monopoly and was heavily regulated by the Montana PSC. It was vertically integrated, controlling almost the complete supply chain related to the generation, transmission and distribution of electricity. After selling the generation assets to PPL, MPC sold the remainder of their electrical business to

NorthWestern Energy. NorthWestern Energy, which did not control or own any generation in Montana, relied on the wholesale electrical market to meet its demand obligations.

This project explores the implications of PPL's market power through five chapters. The first chapter reviews the history of the Montana electrical market. It chronicles the creation of the MPC, the construction of electrical generation in Montana, and the reorganization of the industry after deregulation. The second chapter reviews the the creation of "Open Access" policies by the FERC, which facilitated deregulation; the process of natural monopoly regulation (the historical structure for the regulation of the MPC); and the regulation of market power in electrical markets by the FERC. The chapter focuses on the FERC's review of PPL, which took place from 2004-2007. The third chapter reviews the economic literature regarding market power in electrical markets, the Cournot and Supply Function Equilibrium models, and established economic approaches to identifying market power. It proposes several approaches to identifying market power in electrical markets based on the economic literature, and discusses the role of Independent System Operators in providing efficient market outcomes. The fourth chapter profiles the structure of Montana's electrical industry, proposes an equilibrium model for the Montana electrical market, and catalogs NorthWestern Energy's efforts to rebuild a vertically integrated electric utility. The chapter presents three empirical calculations to illuminate the magnitude of PPL's market power: A compensating variation analysis comparing the rates of Idaho Power and NorthWestern Energy, estimates of PPL's revenues and profits, and the Lerner Index, or mark-up, for PPL. The fifth chapter summarizes the work and major findings.

This thesis demonstrates that the FERC's review and regulation of horizontal market power is inadequate. Simply, the FERC's reliance on concentration measures as an indication of a firm's market power does not capture the incentives of firms or present meaningful results of a firm's capacity to exercise market power in electrical markets.   The implication for Montanans has been a consistent and pervasive transfer of wealth to PPL, which is estimated to be an average of $120 million annually, and still ongoing.

While the situation has potentially stabilized, through ongoing vertical integration by NorthWestern Energy, there are clouds on the horizon. A fixed contract between PPL and NorthWestern Energy, that today is NorthWestern Energy's only source of electricity from PPL, is set to expire in 2014. Regional utilities are also looking to the wholesale electrical market to balance growing variability, caused by increased wind generation, and as a source of long-term energy supply. However, unlike the vast majority of the United States, there is no organization – a specified and predictable scheme for determining market prices – in the region. Policy makers should consider such systems, commonly referred to as Independent System Operators, as a forward tool to enhance market outcomes and efficiency.

VI A Note on Units in the Electrical Industry

This project describes electricity production capacity in megawatts (MW). In order to denote energy, megawatts are typically described in MW hours, or MWh, to reflect one hour of production of electric energy. As there are 8,760 hours in non-leap years, the generation from a facility or demand can be expressed in average megawatts, or aMWs, by dividing annual production by 8,760. A single megawatt of energy is sufficient to meet the instantaneous needs of about five hundred homes. As such, retail electrical demand is typically described in kilowatt hours (kWh). Electrical bills are typically denoted in KWh with customer pricing in cents, such as nine cents per KWh. As 1,000 kWh is equal to 1 MWh, an MWh price of $100 would be equivalent to a kWh price of $.10 or 10 cents or 100 mills.

1: History of the Montana Electrical Market

This chapter reviews the history of electric energy development in Montana and catalogs the growth of generation capacity. The focus is on the transactional and policy history related to the deregulation of the Montana electric industry. This chapter chronicles the expansive growth in generation capacity from 2004 through 2011.

1.1 Building MPC (1884-1940)

Electricity first came to Montana in 1884, to light what was then one of the largest cities west of the Mississippi, Butte.[1] From there, the development of Montana's electrical infrastructure was inextricably linked to nationwide electrical development, as Butte was the source of the necessary copper, and the mines needed electricity to procure it. Small municipal lighting projects soon spread to the cities of Helena, Missoula, and Billings. Each project originally relied on small steam generators, but as demand grew, new, larger sources of energy were required, and so began the damming of Montana's rivers.

The first dam was on the Big Hole River, which after failing in the spring of 1888, was reconstructed to provide three MW of electricity to Butte via a 15 kilovolt ("kV") transmission line and was fully operational in the fall of 1899. Meanwhile, a dam was constructed on the Missouri River near Helena, which was completed in the fall of 1898 and provided 2.2 MW of electricity to Helena. With Butte's demand growing, a new project was started on the Madison River and the Missouri River dam enlarged. The Madison River dam, completed in 1901, required the construction of a 60 kV (though operated at 40

[1] Any historical information prior to 1970 that is not cited in this chapter is derived from the extensive work of Cecil H. Kirk's *A History of the Montana Power Company* (Kirk and Bauer, 2008). Mr. Kirk's effectively encyclopedic history of the MPC through 1969, was not published until 2008, after much effort by his daughter to extract the work from NorthWestern Energy (MPC would not print his original work, which they had financed). The work also includes a section covering MPC from 1970-2002 by Anne Bauer.

kV) transmission line to move the power to Butte. 50 kV lines were built from the Missouri River dam, which had been expanded to 4.5 MW, to Butte and Anaconda, and began operating in 1902. Excluding steam generation, by 1902, Montana had 9.5 MW of hydroelectric generation capacity whose purpose was primarily to serve Butte loads. By the end of 2012, Montana will likely have over 6,000 MW of electrical generation capacity.

With demand for copper continuing to grow, electrical demand increased, and the industry required more sophisticated methods of financing and organization. On November 8, 1912, the MPC incorporated in New Jersey, creating the vehicle for consolidation of electrical service providers in the state. Three days later, the MPC board adopted the consolidation and merger with the Butte Electric and Power Company (which served the Butte mines, and owned the Big Hole dam), the Madison River Power Company (which owned the Madison River projects), the Billings and Eastern Montana Power Company, and the Missouri River Electric Power Company. The Great Falls Water Company was acquired by the MPC in February 1913. Over the next thirty years, the MPC acquired additional municipal electrification projects across the state including Havre in 1914, Hardin in 1924, and Missoula in 1929 (Montana Power Company, 1941).[2]

From its incorporation until the start of World War II in 1940, the MPC engaged in expansive hydroelectric development to meet growing loads, and several high-voltage interconnection projects to connect Montana cities and provide stable electricity service. By 1940, the MPC was operating 349.75 MW of hydroelectric dams, which included dams on the Clark Fork, West Rosebud, Madison, Missouri, and an interconnected electrical grid that stretched from Missoula to Billings. Table 1.1.1 provides the capacity of each plant.

[2] MPC acquired all of the electrical loads associated with municipalities in Montana, except those outside of the Western Interconnect and Kalispell and Libby. These loads were serviced by Mountain States Power, which merged with Pacific Power & Light (now PacifiCorp) in 1954. See, http://www.library.hbs.edu/hc/lehman/company.html?company=montecatini

Table 1.1.1 Hydroelectric Capacity of the MPC (1941)

Plant	Capacity (MW)
Black Eagle	18
Canyon Ferry	7.5
Dillon	.25
Flint Creek	1.1
Hauser Lake	18
Holter	50
Kerr	56
Madison	9
Milltown	3.4
Mornoy	45
Mystic Lake	11.5
Rainbow	35
Thompson Falls	35
Volta (Ryan Dam)	60

1.2 Federal Action Spurs Rural Electrification and More Dams (1940-1970)

In the late 1930s, the United States Congress passed several important pieces of legislation that set the template for electrical power development over the next thirty years. These acts included the Federal Power Act of 1920 & 1935, the Rural Electrification Act of 1936, and various appropriations under the New Deal.

Beginning in 1937, Montanans organized Rural Electrical Cooperatives to provide electrical service to rural areas that had been overlooked by the urban-focused development of initial electrification. By 1941, ten separate cooperatives had been formed and were receiving electrical service from new substations on the MPC's high-voltage transmission system. The cooperatives distributed the electricity from the MPC to their members through retail lines that they owned. Concurrently, New Deal funds financed the construction of several large hydroelectric dams that would provide power to the cooperatives through the MPC's high-voltage transmission. By 1975, the federal government had built 1,388 MW of capacity at four dams in Montana: Fort Peck, Libby, Yellowtail and Hungry Horse.

One intention of the Federal Power Act was to break the trusts that controlled much of the United States' electrical infrastructure. This included the MPC, which New York capitalists had created and was controlled at that time by the American Power & Light Company. In 1949, the Securities and Exchange Commission ordered American Power & Light Company to distribute the MPC shares to their shareholders.[3] With this action, the MPC became an independent and publically listed company.

During this period the construction of federal hydroelectric projects dwarfed the MPC's expansion of capacity. The MPC's efforts to develop new dam sites, including a multi-utility project in Idaho were not fruitful, and the MPC never again built a new hydroelectric dam after the Cochrane Dam in 1958. The MPC then began to focus on thermal generation (combustion based steam generation) to meet growing demand. In 1951, MPC built the 66 MW Frank Bird Steam plant in Billings in 1951 (later retired), and the JE Corette coal-fired station on an adjacent site in 1968, which today has a thermal capacity of 154 MW. Washington Water & Power Company (now Avista) developed the Cabinet Gorge and Noxon Rapids dams on the Clark Fork River during the 1950s.[4] Montana-Dakota Utilities completed the 50 MW Lewis and Clark coal plant in Sydney in 1958, which is still operational today (Energy Information Association, 2008).

The World War II war effort increased electrical demand and spurred high-voltage interconnection between utilities. This led to coordinated interchange of electricity by adjacent utilities in the west and the creation of a regional interconnected electrical system. First, a 161 kV line was extended from

[3] American Power & Light Co. v. Securities & Exchange Commission, 329 U.S. 90 (1946).

[4] Noxon Rapids facility had an original capacity of 420 MW and began operations in 1959. Each generator is being upgraded so that the facility will have a total capacity of 448 MW at the end of 2011. The Cabinet Gorge dam has a capacity of 265 MW and began operations in 1952, and is located approximately 2 miles east of the Idaho-Montana border.

Anaconda, Montana to Grace, Idaho, which allowed for a direct interconnection between Idaho and Montana.[5] Dual 100 kV lines already connected the MPC with the Washington Water & Power Company through an expansion in 1914 to serve loads associated with mining at Coeur d'Alene, Idaho. These high-voltage interconnections facilitated the formation of NorthWest Power Pool in 1941, which continues to exist today. The NorthWest Power Pool facilitates power exchanges by its six original member utilities, now 33, to help meet peak loads, and to exchange power during facility outages or periods of low hydroelectric production.[6]

Increased coordination and interchange eventually led to the formation of a regional interchange in 1967 by 40 electric power systems, known today as the Western Electricity Coordination Council, or western interconnect. This is one of three distinct transmission systems in North America, with each system operating independently and out of phase with the others. The boundary between the western and the eastern interconnect runs generally from the Fort Peck dam (whose generators can move power into either interconnect) south to Miles City and then along the eastern border of Wyoming and Colorado. Electricity is transferred from one interconnect to the other through the use of direct current ties, such as a 50 MW transfer at Miles City. Currently the Western Electricity Coordination Council is proportioned into 19 separate Balancing Authority Areas. For instance, NorthWestern Energy operates a Balancing Authority Area for the footprint of its transmission system, which interconnects with Idaho Power and PacifiCorp to the south, Bonneville Power Administration and Avista to the west, and the

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[5] It is unclear if interconnection was with Idaho Power or Utah Power & Light, which both served loads in Idaho. Utah Power & Light is now known as Rocky Mountain Power. PacifiCorp owns both Pacific Power & Light and Rocky Mountain Power.

[6] The six original members were: MPC, Washington Water & Power Company, Pacific Power & Light, Puget Sound Power & Light, The NorthWestern Electric Company (which later merged with Pacific Power), and Seattle City & Light. Five additional members joined in 1942 per the requirements of the War-Acts: BPA, Portland General Electric, Tacoma City Light, Seattle City & Light, Utah Power & Light, and Idaho Power Company. In 1949 British Columbia Hydro joined. Today the NWPP has 33 members.

generation-only Balancing Authority Area of Glacier to the north.[7] These connections are described in further detail in Section 4.2.

During the 1960s, members of the NorthWest Power Pool coordinated on several transmission and energy development projects. First, they constructed a 230 kV system that ran from Hot Springs, Montana (the interface of the Washington Water & Power Company's system with MPC's) to Anaconda, Montana with one line running south to American Falls, Idaho, and another onto Yellowtail through Billings, and continuing through Wyoming to Naughton and on to Salt Lake City. The second project was the High Mountain Sheep Project, a $300-$500 million dollar hydroelectric development on the Snake River confluence with the Salmon River in Idaho. While portions of the 230 kV systems were completed, the High Mountain Sheep project failed due to opposition by the Department of Interior.[8]

1.3 Coal (1970-1992)

The spirit of collaborative electrical infrastructure development continued into the 1970s, with construction of two new thermal resources in Colstrip, Montana, under a partnership between Puget Sound Energy and the MPC. MPC had formed a subsidiary, Western Energy in 1968 to extract coal at Colstrip, for which it had acquired the lease rights in 1959. Colstrip Unit 1 began operation in 1975, followed by Colstrip Unit 2 in 1976. Each plant had a capacity of 307 MW and was connected to the 230 kV system with a 230 kV line from Colstrip to Billings, built to 500 kV specifications.

The development of Colstrip Units 1 and 2 was just the surface of ambitious plans by utilities to tap the coal reserves of the Colstrip area. Plans called for 200,000 MW of new coal capacities and transmission superhighways connecting these plants to new loads on the west coast and Midwest. In

[7] The completion of the Montana Alberta Tie Line, from Great Falls, Montana to Lethbridge, Alberta, will add an interconnection with the Alberta Independent System Operator. Construction of the line is underway, but several lawsuits regarding eminent domain could stop the line. The line is expected to be completed in 2012.

[8] *Udall v. FPC*, 387 U.S. 428 (1967).

1973, the MPC, Puget Sound Power & Light, Washington Water & Power, and Portland General Electric announced plans to build an additional unit at Colstrip with a generation capacity of 700 MW.

The MPC's quest to develop Colstrip resulted in a significant political battle between the MPC, regulators, ranchers, and the conservation community. The MPC's announcement came on the heels of Montana's new Constitution, ratified in 1972, that provided for increased citizen participation and an inalienable right to a "clean and healthful" environment.[9] In the wake of the proposed development, citizen groups, such as the Northern Plains Resource Council, formed to oppose the transmission and coal expansion proposed by the MPC and its partners. They lobbied the Montana Legislature, which strengthened facility siting laws, and worked to pass federal legislation to reclaim coal mines and protect air quality. After ten years of protracted battles, construction at Colstrip finally proceeded on 1,480 MW of coal capacity and a double circuit 500 kV line. Table 1.3.1 describes the ownership of the new thermal plants, known as Colstrip Units 3 and 4. Non-MPC output from the Colstrip units is transmitted on a 500 kV line owned by MPC to Townsend, Montana, where ownership in the line changes to the Bonneville Power Administration, to allow for delivery to the other owners' transmission systems west of Montana.[10]

Table 1.3.1 Ownership of Colstrip Unit's 3 and 4 (1986)

Plant/Owner	Private Interest	MPC	Avista	Portland General Electric	Puget Sound Energy	PacifiCorp
Colstrip Unit 3		30%	15%	20%	25%	10%
Colstrip Unit 4	30%[11]		15%	20%	25%	10%

[9] Montana Constitution article II, § 3.

[10] The complex ownership agreement of the Colstrip line was necessary to facilitate a number of permitting and rate-making concerns of individual utilities.

[11] NorthWestern Energy now owns this capacity.

The Public Utilities Regulatory Policy Act in was passed in 1978. It required that utilities purchase power at their "avoided cost" rate from qualifying facilities, such as renewable energy or facilities that generated electricity from waste heat.[12] This law caused the development of 104.75 MW of capacity that is in operation today in Montana, most related to converting waste heat to electricity from refineries in the Billings area or the Colstrip plants. Table 1.3.2 shows a breakdown of major qualifying facilities by year of construction, location, and capacity contribution that serve NorthWestern Energy's loads today.

Table 1.3.2 Qualifying Facility Plant Development (2010)

Plant Name	Capacity (MW) [13]	Primary Mover	On-line Date
Broadwater Dam	10	Hydro	1989
Colstrip Energy Limited Partnership	35	Thermal	1990
Billings Generation	52	Thermal	1995
Tiber Dam	7.5	Hydro	2004
United Materials of Great Falls	9	Wind	2006
16 Facilities, <2 MW capacity	7.75	Hydro/wind	

1.4 Montana Power Company Exits (1992-2001)

After eighty years of being Montana's default electrical supplier, in just four years the MPC completely removed itself from the electrical power business. The federal Energy Policy Act of 1992 set the transition in motion. It required that the FERC oversee the functional unbundling of the high-voltage transmission system from generation and wholesale activities, which the FERC had already begun on a case-by-case basis.[14] In April 1996, the FERC published Order 888 which extended this process to all transmission providers. Order 888 created the rules and procedures for electric generators to access

[12] The avoided cost rate is determined by each state regulatory commission.

[13] Capacities reflect reported loads in NorthWestern Energy's network resource list available on their OASIS. See, http://www.oatioasis.com/NWMT/NWMTdocs/List_of_Current_Network_Resources.pdf

[14] Chapter 2 describes the impacts of the bill more fully.

the transmission system, thereby creating the regulatory template for competition and deregulation of the industry (FERC Order 888).

The Montana Legislature's actions would be the catalyst for sweeping changes to Montana's electric industry during this period. First, legislation passed in 1993 requiring the MPC to competitively procure resources and engage in biannual integrated resources planning. As a result, the MPC procured 98 MW of winter capacity from Basin Electric Cooperative, a 50 MW exchange with Idaho Power, and a 41 MW expansion of the Thompson Falls Dam.

Then in 1997, the Republican controlled Montana Legislature passed Senate Bill 390, the "Electric Utility Industry Restructuring and Customer Choice Act," which was signed by then-Governor Mark Racicot.   The intent of the legislation was to promote retail competition, by allowing customers to select a retail service provider, much like one selects a cable or internet provider. Senate Bill 390 also authorized the MPC to deregulate its electrical business through the sale, or divestiture, of its generation and transmission assets, though this outcome was not necessarily intended by the Legislature. The MPC had actually opposed mandatory "divestiture" language during the Legislature, which would have required them to sell their generation assets (Judge, 2000). The MPC had previously placed these resources in the "rate-base", which allowed for the recovery of their average cost through rates to Montana consumers as regulated by the Montana PSC.[15]

In November 1998, the MPC announced that PPL would purchase its generation assets for $988 million, with $152 million of the deal contingent on the inclusion of Puget Sound Energy's and Portland General Electric's share of Colstrip Units 1, 2 and 3. The deal closed on December 17, 1999 with PPL acquiring only the MPC's interest in Colstrip Units 1, 2 and 3, for $836 million as the respective state regulatory bodies would not approve the sales by Portland General Electric and Puget Sound Energy.

[15] See Chapter 2 for more detail on natural monopoly regulation.

PPL then owned the facilities in Table 1.3.3, and applicable transmission rights on the 500 kV transmission system.[16]

Table 1.3.3 PPL's Assets (2010)

Plant	Capacity (MW)	Location	On-Line
Madison Dam & Hebgen Storage	9	Madison River	1906
Rainbow Dam	35 (62 in 2011)	Missouri River	1910
Thompson Falls Dam	86	Clark Fork River	1915
Ryan Dam	60	Missouri River	1915
Hauser Dam	17	Missouri River	1918
Holter Dam	50	Missouri River	1918
Mystic Dam	11	West Rosebud River	1925
Black Eagle Dam	18	Missouri River	1927
Morony Dam	48	Missouri River	1930
Kerr Dam[17]	189	Flathead River	1938
Cochrane Dam	54	Missouri River	1958
J.E. Corrette Plant	163	Billings	1968
Colstrip 1 Interest	50% (153.5)	Colstrip	1975
Colstrip 2 Interest	50% (153.5)	Colstrip	1976
Colstrip 3 Interest	30% (222)	Colstrip	1984
Total	**1,296 (2011)**		

In September 2000, the MPC board authorized the sale of the remaining MPC assets related to its electrical and natural gas supply business. The MPC sold the remaining natural gas and electrical utility business units and the Milltown Dam to NorthWestern Energy.[18] The terms of Senate Bill 390 required PPL to continue supplying NorthWestern Energy's customers through the second quarter of 2002 at rates that did not exceed those in effect at the end of second quarter of 1998.[19]

[16] The MPC retained control of the 3 MW of capacity at Milltown Dam, which was later removed as part of the Milltown Restoration Project.

[17] The Confederated Salish and Kootenai Tribes have an opportunity to purchase the dam in 2014, and are currently negotiating with PPL to determine the price.

[18] NorthWestern Energy is the business name for NorthWestern Corporation in Montana.

[19] Montana Code Annotated § 69-8-211(6)(b) (1997)

Deregulation also precipitated additional restructuring in the electrical industry in Montana. In 1998, PacifiCorp sold it Kalispell service territory, which had never been acquired by the MPC, to the local electrical cooperative, Flathead. Flathead subsequently organized this business into the for-profit entity Energy NorthWest Inc. for a period of time. The 222 MW share of Colstrip Unit 4 held by private interests was sold to Duke Energy and subsequently purchased by NorthWestern Energy before being placed in the rate-base in 2008.

Senate Bill 390 provided for a phase-in of deregulation, starting first with industrial consumers, which were allowed to select a different wholesale electrical supplier from July 1, 1998 through July 1, 2002. By July 1, 2002, or no later than 2004 (if so delayed by the Montana PSC), retail customers with loads less than 300 kW could choose a competitive electric supplier. The Electrical Industry Restructuring Transition Advisory Committee, which was created by Senate Bill 390 to oversee deregulation, noted in its 1999 Report that 21 companies had been licensed by the Montana PSC to supply retail electricity, and loads from 330 customers, or 25% of the MPC's retail base, had elected to leave. Senate Bill 390 also contained cost cap provisions, which prohibited rate increases through July 1, 2002. As of 2000, these rates were $22.25 per MWh, or $29.61 in 2010 dollars, and expired on June 30, 2002 (ETAC, 2000). The provisions allowed for recovery of increased transmission costs beginning in 2000, as well as emergency cost waivers by the Montana PSC.[20]

The 2003 legislature removed the cost cap provisions and restricted the quantity of loads allowed to choose a competitive electric supplier. Loads choosing to leave the default supplier had to be between .05 MW (50 kW) and five MW in size, and total loads leaving could not be more than 20 MW. In 2009 loads outside of default supply amounted to 317.6 total MW.[21] In 2010, PPL served 279 MW of these

[20] Montana Code Annotated § (69-8-211) (1997)
[21] NorthWestern Energy, Montana PSC Docket N2011.1.1, "9/30/2011 Updated Compliance Filing Response"

loads through NorthWestern Energy's transmission system, as a result of deregulation. Table 1.3.4 describes these loads.

Table 1.3.4 Industrial Loads Served by PPL Montana (2010)[22]

Company	Location	Demand (MW)
Ash Grove Cement Company	Clancy	6
Aspen Air Corporation	Billings	5
Cenex Harvest States	Laurel	29
Colstrip Steam Electric Station	Colstrip	9
ExxonMobil Corporation	Billings	35
Holcim US Inc.	Three Forks	6
Luzenac America	Three Forks	5
Montana Resources	Butte	43
REC	Butte	105
Roseburg Forest Products	Missoula	8
Smurfit-Stone Container Corp.	Frenchtown	3
Stillwater Mining Company	Columbus & Nye	23
Stimson Lumber Company	Bonner	2

1.5 NorthWestern Energy and the Addition of Wind and Gas (2001 -2010)

Montana's experiment with deregulation officially ended with the passage of House Bill 25 by the Montana Legislature in 2007, which Governor Brian Schweitzer signed into law. House Bill 25 stopped the consumer choice provisions on deregulation for all customers less than five MW, and allowed NorthWestern Energy to own generation assets to meet its retail load obligations.[23]

Prior to House Bill 25's passage, few competitive electrical suppliers had emerged. One was Electric City of Great Falls which continues to sell electricity, though it is not likely that this entity will continue.[24] In the fall of 2004, the City of Great Falls petitioned the Montana PSC to serve certain electrical supply

22 Developed from http://www.oatioasis.com/NWMT/NWMTdocs/List_of_Current_Network_Resources.pdf.

23 See, http://data.opi.mt.gov/bills/2007/billhtml/HB0025.htm. Montana Law still allows for customers of Electric City of Great Falls to add new meters associated with expansions of their facilities.

24 During the fall of 2011, several large loads that had been served by Electric City Power transferred to PPL. The Great Falls City Commission also appears to be looking for an exit from their power business, which has several million dollars in liabilities.

customers as a municipal utility. The City reorganized in 2006 under Electric City of Great Falls. As of the third quarter of 2010, the loads served by Electric City amounted to 28.5 aMW or 250,000 MWh annually.[25]

The six years between the purchase of Montana's retail customers by NorthWestern Energy and the restructuring of Montana's electrical industry were eventful. First, in September 2003, NorthWestern Energy filed for bankruptcy after shareholders failed to agree to a plan to issue 200 million new shares to cover $2.2 billion in debt.[26] NorthWestern Energy eventually restructured, and emerged from bankruptcy on November 1, 2004.[27]

In April of 2006, NorthWestern Energy announced plans to sell to an Australian utility, Babcock & Brown Infrastructure Partners.[28] The Montana PSC eventually rejected the deal in mid-2007. Meanwhile, NorthWestern Energy rejected two other public bids to acquire its Montana assets, one by five major Montana cities, led by than Missoula Mayor Mike Kadas, and another from the Black Hills Corporation of South Dakota.[29] In August 2008 NorthWestern Energy replaced Mike Hanson, CEO since 2003, with former Democratic Montana PSC Commissioner Bob Rowe. This change was regarded as a commitment by NorthWestern Energy to staying in Montana and also to rebuilding a vertically

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[25] Associated Press, "Great Falls wants out of power business", 11/2/2010. See, http://billingsgazette.com/news/state-and-regional/montana/article_f181aec4-e69c-11df-b9d7-001cc4c03286.html

[26] Associated Press, "NorthWestern Corp. files for bankruptcy", 9/14/2003, Billings Gazette. See, http://billingsgazette.com/business/article_8dce790a-7841-5152-88bf-d0a8ff09687f.html

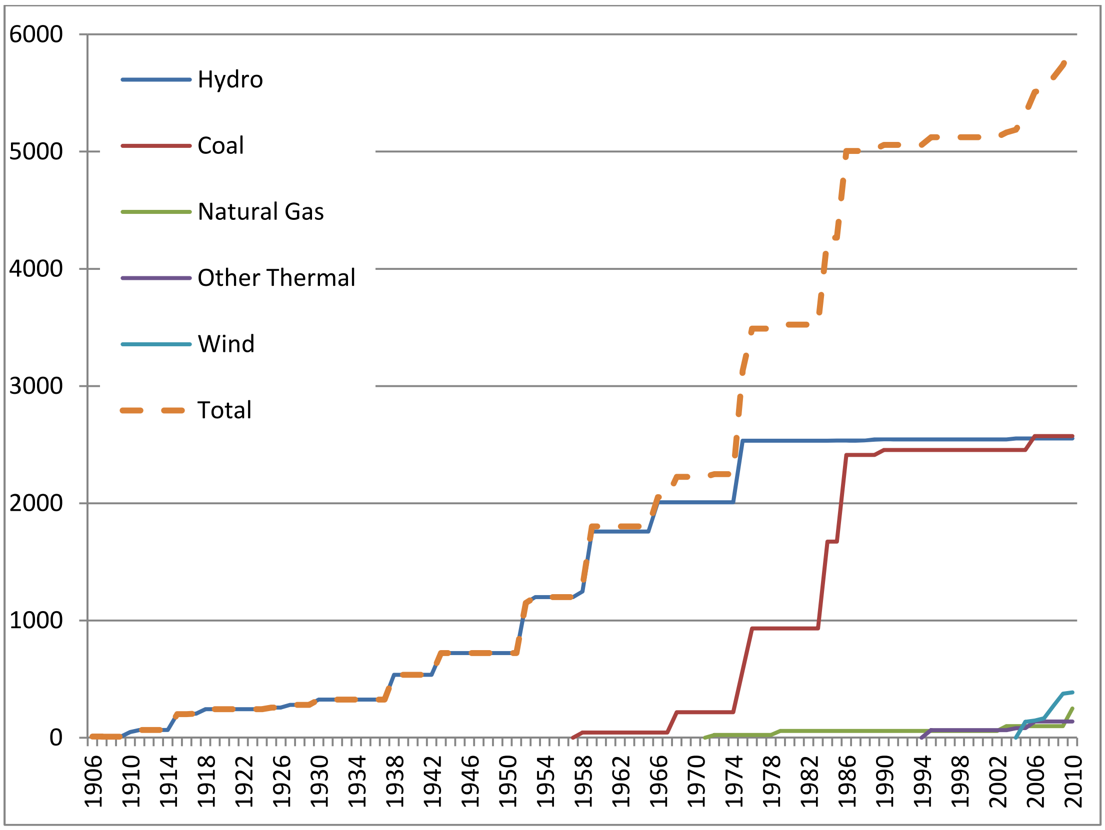
[27] Jan Falstad, "Judge approves Nov. 1 end of bankruptcy for NWC", 10/19/2004, Billings Gazette. See, http://billingsgazette.com/business/article_12628486-e331-50dc-876c-a6c24d05e2cf.html

[28] http://billingsgazette.com/news/state-and-regional/montana/article_0585b83e-07cf-5639-90ed-4520bf1edb31.html

[29] Associated Press, "NorthWestern Declines Merger" 12/10/2005, Billings Gazette. See, http://billingsgazette.com/news/state-and-regional/montana/article_df415a4a-e234-5663-b6e9-dc9418e1b35f.html

integrated electrical utility.[30] The period from 2006-2010 also saw a rapid expansion of electrical generation capacity in Montana. Figure 1.5.1 shows the growth of Montana's electrical capacity by major fuel source.

Figure 1.5.1 Montana Historical Capacity Growth (2010)



Four wind energy facilities were built in Montana from 2005-2009. First, Invenergy completed construction of the 135 MW Judith Gap wind farm in 2005, which provides energy to NorthWestern Energy at a twenty-year fixed rate. Second, the nine MW Horseshoe Bend Wind facility was constructed at Great Falls, and is currently owned by United Materials of Great Falls. Then in 2008 and 2009, NaturEner completed the first and second phases of the 210 MW Glacier Wind Parks in Toole County. NaturEner developed these projects to provide renewable energy credits to California utilities

[30] Mike Dennison, "NorthWestern CEO Hanson out; Former Montana PSC Chair in" 8/12/2008, Billings Gazette. See, http://billingsgazette.com/news/state-and-regional/montana/article_d92aac76-690a-5ad1-840a-4267af21dc03.html. Mr. Rowe continues to serve as CEO.

to assist in compliance obligations with California's renewable energy requirements.[31] Output from the Glacier Wind Parks is sold on wholesale electricity market.[32] Montana-Dakota Utilities also completed construction of 19.5 MW of wind capacity at its Diamond Willow site in 2007, and added 10.5 MW in 2010.

Wind development is continuing in Montana. NorthWestern Energy has executed agreements for 49 MW of new qualifying facility wind power, slated to come on-line in 2011 or 2012 and is seeking approval of 45 MW of rate-based wind power at Spion Kop, which would come on-line in 2012. NaturEner is proceeding with the construction of 189 MW of wind at their Rimrock facility near Conrad, Montana, which is expected to be on-line in 2012.

In addition to wind, there were also several thermal and small hydroelectric plants constructed. The 116 MW Hardin Generation Station, a coal-powered plant, was completed in 2006 and is currently owned by Rocky Mountain Power (PacifiCorp).[33] Basin Creek Electric partners developed a 54.8 MW gas fired facility in Butte which came on-line in 2006. This plant provides capacity and energy under a long-term contract to NorthWestern Energy. Two small hydroelectric facilities came on-line, the 7.5 MW Tiber Dam in 2004 and the 13 MW Turnbull hydroelectric facility in 2011. PPL upgraded the turbines at its Rainbow Dam, which will double its capacity to 62 MW once completed in 2011. On the eve of the fourth quarter of 2010, the Dave Gates Generating Station began operating near Mill Creek outside of Anaconda. This facility provides up to 150 MW of balancing capacity or ancillary services. Finally, in the

[31] The first phase, Glacier 1, was constructed in 2008 and consists of 106.5 MW of capacity. Glacier 2, the second phase, was completed in 2009 with a capacity 103.5 MW for a total project capacity of 210 MW.

[32] California Public Utilities Commission, Energy Division Resolution E-4192, see, http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/91720.pdf

[33] The plant was originally built by a subsidiary of Montana-Dakota Utilities, which sold a portion of the of the facility's power to Powerex, who then remarketed the power. PacifiCorp apparently bought the facility in 2007.

third quarter of 2011 Southern Montana Electric initialized the first phase of Highwood Generation station, with 40 MW of natural gas fired capacity.[34]

From 2004 through 2011, there was significantly more capacity added to the Montana electrical market than demand growth. This level of firm entry may have resulted from delayed plant construction during the phase-in of deregulation or may have been attributable to high prices attributable to PPL's exercise of market power which incented firm entry. All told, 893.3 MW of new capacity, excluding the Diamond Willow Projects, was added. Excluding the Rocky Mountain Power Project at Hardin and the Dave Gates and Basin natural gas additions (which primarily provide ancillary services or energy to out-of-state-loads) the net addition of capacity was 486.5 MW. This is more than four times the capacity added during the previous twenty years (1984-2004). This capacity represent approximately 217.5 aMW, which is almost four times the statewide load growth from 2004-2009 of 57 aMW.[35]

Part of this added capacity resulted from the passage of the Renewable Power Production and Rural Economic Development Act in 2005. This act mandated that competitive electric supplies (largely, NorthWestern Energy, PPL and Montana-Dakota Utilities) procure renewable energy credits equivalent to ten percent of demand by 2010 and fifteen percent by 2015. Judith Gap largely meets NorthWestern Energy's 2010 compliance needs, with the Diamond Willow Projects supporting those of Montana-Dakota Utilities.

Other portions of this capacity serve the wholesale electricity market. The Hardin Generation Station initially did not have any commitments for its energy and sold the output to the wholesale energy marketer, Powerex Corporation. The 210 MW of capacity at the Glacier Wind Projects has

[34] A complete index of electrical generation capacity in Montana is provided in Appendix II.
[35] United States Energy Information Institute Table 10a, see, http://www.eia.gov/cneaf/electricity/esr/backissues.html.

minimal firm capacity to transmit electricity outside Montana and must sell its output to receive revenue from the environmental attributes or green tags sold for compliance with the California's renewable energy requirements. The Hardin Generation Station and the Glacier Wind Projects represent 169 aMW of capacity, almost three times the 57 aMW of load growth from 2004-2009 in the state.

Demand side management or conservation has also contributed to resources needs. Regional conservation efforts that began in the 1970s have effectively created new electrical capacity by improving the efficiency of existing energy use. On a regional scale, conservation has likely delayed the construction of new power plants during the 1980s and 1990s, as utilities captured efficiency through the energy efficiency measures. The Northwest Power Council has estimated that NorthWestern Energy captured 6.33 aMW in new capacity from energy efficiency work in 2009 alone.[36] Cumulative regional conservation since 1978 in the Pacific Northwest is estimated at over 4,500 aMW of capacity.[37]

1.6 Conclusion

The structure of Montana's electrical market has experienced profound changes in the last decade. It appears that the structure has stabilized with NorthWestern Energy concentrated on rebuilding a vertically integrated electrical utility. The legacy of deregulation has permanently separated certain large industrial customers from retail supply, giving these customers a unique ability to select a wholesale electricity provider. NorthWestern Energy has also secured over 200 MW of natural gas capacity through Mill Creek and Basin Creek, which provides flexibility to balance loads and resources and meet contingency obligations. The period was also marked by extensive generator entry into the

[36] For a review of conservation activities in the Pacific Northwest see, http://www.ptr.nwcouncil.org/apps/RCPMultiYearDisplayClean.asp?SID=0&lFS=0&UID=176&ptryearid=12

[37] See, http://www.nwcouncil.org/energy/rtf/consreport/2010/2011_10presentation.pdf

market, which suggests that high prices, possibly the cause of market power, may have led firms to enter the market in excess of demand growth.

2: The Regulation of Market Power in Electrical Markets

This chapter will cover the FERC's attempts to mitigate vertical market power through the regulation of natural monopolies (2.1), the creation of the Open Access Transmission Tariff (2.2), regulations regarding horizontal market power (2.3), and the procedural history of PPL's filings regarding horizontal market power in Montana with the FERC (2.4).

In electrical markets, market power is described in two broad categories: vertical and horizontal. Vertical market power exists when a utility uses the ownership of upstream assets (fuel sources, or transmission assets) to create market power downstream, such as by restricting the access of a competing generator to the transmission system. Horizontal market power is gained through a utility's general market position that allows it to set the market price. The FERC has consistently determined that its Open Access polices are an effective mitigation for most vertical market power in the electrical industry, and has focused its market power review on issues of horizontal market power (FERC, Order 697).

2.1 Natural Monopoly Regulation

This section will review state-based regulatory policies for natural monopolies to recover costs from the construction of new generation and discuss the economic benefits of vertical integration in electric utilities.

Historically, electric utilities were vertically integrated. A single utility, such as MPC, owned all aspects of generation, transmission, and distribution of electricity, and could exclude other firms from using these systems or supplying customers. Under this structure, the utility constructed new generation and transmission assets as necessary to meet demand growth. For each plant the utility would propose a cost recovery structure to the relevant public utility commission and seek approval that the rates and terms it planned to charge customers were reasonable and prudent. The utility would seek a specific authorized rate of return on its equity contribution and propose a debt to equity ratio to finance the construction of the facility. Often a utility seeks a 50-50 debt to equity ratio and a rate of return on their equity of 10-12%. With a debt cost of 6-8% percent, the interest to customers would be a blended rate of 8-10% percent for the capital costs of the facility.

For example, NorthWestern Energy has recently undertaken this approval process for the Spion Kop Wind Facility, a potential 45 MW wind plant in Geyser County, Montana.[38] This will be the third generation facility for which NorthWestern Energy will seek cost-recovery from the Montana PSC.[39] NorthWestern Energy has proposed a capital structure of 52% percent debt and 48% percent equity. NorthWestern Energy is seeking a 10.25% return on equity and an estimated 5% cost of debt, resulting in a blended cost of capital of 7.52%. The 45 MW facility is estimated to cost $86,115,035. If it is capitalized in this capital structure and realizes certain tax benefits (a production tax credit, and bonus depreciation) it will result in a 25 year levelized cost to rate-payers of $53.78 per MWh.[40]

Vertical integration and state utility commission regulation provide long-term welfare benefits. As retail rates are fixed for consumers in the long run, the structure is equivalent to a forward contract by consumers with the utility that provides rate stability and encourages long-term capital investment even in the presence of a competitive market. These legacy structures of vertical integration can strongly influence competitive outcomes. By creating a forward relationship with customers, firms reduce the quantity of electricity that they have to sell on the wholesale market. Consequently, they

[38] See, Montana PSC Docket, D2011.5.41.

[39] The previous two were the 222 MW portion of Colstrip Unit 4, and the 150 MW Dave Gates Generating Station.

[40] See, http://psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2011-5-41_IN_20110531_AP.pdf (p. 4 & 5).

have less incentive to raise prices on the wholesale market.[41] The forward contracts thus act to provide pro-competitive structures that reduce the incentives for market manipulation (Bushnell, et al. 2005).[42]

The authorization of new generation and the management of recovering other utility costs, such as those associated with new transmission, form the fundamental structures of state-based utility regulations. Often these processes have adjacent planning efforts, where state regulators will require the development of integrated resource plans and transmission plans, to identify the least cost resource portfolio to meet expected demands. Many states also require certain low-income assistance, specific investments in energy conservation, and mandatory renewable energy targets.

2.2 Open Access

This section will discuss the FERC's regulation of transmission under policies known as "Open Access", the economic benefits of wholesale trade, and the role of Independent System Operators.

The Energy Policy Act of 1992 triggered sweeping changes to the structure of the United States electrical industry and the regulatory powers of the FERC. Previously, the FERC's jurisdiction had revolved around hydroelectric power and interstate sales agreements. The Act mandated that FERC was to direct transmission owners to replace the old model – vertically integrated monopolies, for a new model in which the transmission functions of each utility would be unbundled from the generation and supply of electricity. However, FERC did not mandate the divestiture of a utilities generation assets which was left to the discretion of individual states. The purpose of the new model was to maintain transmission systems as natural monopolies, while creating a platform to move and trade electricity

[41] The empirical work conducted by Bushnell, et al. 2005, offers an important insight into the most efficient market structures for electrical markets. They compare three Independent System Operations in the United States - California, New England and PJM (Pennsylvania) – and predict a competitive market outcome and Cournot outcomes with and without vertical arrangements in the market. Their results suggest that Cournot estimates, when vertical arrangements are considered, are more accurate than perfect competition at predicting wholesale energy prices.

[42] Bushnell, et al. 2005, characterize this as Stackelberg Competition.

across the systems in a non-discriminatory manner (Kirschen and Strbac, 2004).[43] The FERC intended its Open Access policies to facilitate wholesale competition by generators, which they believed would lead to reductions in electrical prices through competition amongst the owners of generation, and the more efficient use of generators (FERC, 1996).

In April 1996, the FERC issued Order 888, the first of a series of orders, to more fully implement the intent of the Energy Policy Act of 1992 and to address the potential for transmission providers to discriminate through access to their transmission system.[44] Order 888 requires all owners of high-voltage transmission to prepare and file uniform - *pro forma* - Open Access Transmission Tariffs that describe the rates and terms under which generators and customers can access and use their transmission system (FERC, 1996). Open Access applies in the same manner to the utility's own energy supply division, and because it is *pro forma*, creates a standard set of rules across the United States transmission system. For instance, NorthWestern Energy and NaturEner have to follow the same rules and procedures to move electricity across NorthWestern Energy's transmission system and NorthWestern Energy cannot give its supply division preference or discriminate against NaturEner. Open Access also specifies a detailed process for generators and industrial loads to interconnect to the transmission system and a variety of requirements to provide transparent and accessible information on the transmission system through a web-based interface known as an OASIS.[45]

The principal benefit of Open Access was to remove transaction costs and barriers for generators to use other transmission systems, in the process removing much of the potential for vertical

[43] The monopoly solution for transmission systems can be derived by considering the cost structure of transmission systems. Transmission systems have large fixed costs with significant economies of scale. A multiple firm solution for a particular geographic market would result in redundant infrastructure. As such, the minimum of average cost occurs in the one firm case.

[44] The Open Access procedural history is voluminous and continues to be updated and refined, with a rule-making underway for variable generators. The FERC's major order website provides electronic copies of the Orders. See, http://www.ferc.gov/legal/maj-ord-reg.asp.

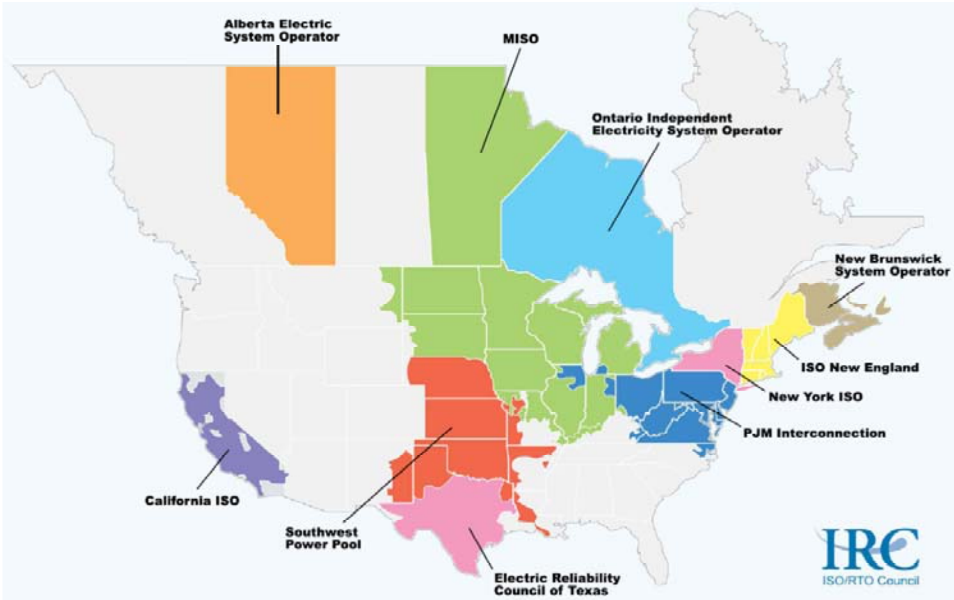
[45] See, http://www.oatioasis.com/NWMT/index.html, for NorthWestern Energy's OASIS.

market power (FERC, 1996). Prior to passage of the Energy Policy Act of 1992, utilities that desired to build generators on another utility's transmission system, or even take short-term delivery of electricity, had to enter into complex bilateral contracts to define the rates and terms for delivery. Under the old rules utilities could also unconditionally deny the interconnection of a new generator to their system, unless the generator was certified as a "qualifying facility" under the 1978 Public Utility Regulatory Policies Act. Open Access rectified this, by providing standard terms, published rates, and a defined right for any entity to use a transmission system. For example, under Open Access, the owners of the Colstrip Units were no longer restricted to using just the 500 kV system to move their power outside of Montana and to their respective transmission systems. If transmission capacity was available, they could move power south - say to Colorado for a sale - with only a few minutes of work by a system operator to file the appropriate schedule and reserve capacity.

The FERC viewed the Open Access process as a bridge measure for the formation of Independent or Regional System Operators, which would operate the transmission system over multiple states (FERC, 2000). Ten Independent System Operators have formed across North America, and serve as the backbone of integrated markets - except in the West and Southwest - for two thirds of United States customers.[46] These independent entities operate the transmission systems of several utilities. They also usually operate both day-ahead and real-time markets for different products that allow for competition among their member utilities and construct the efficient deployment of electrical generators. These markets are often organized with a specific auction format. A map of the service areas of Independent System Operators is provided in Figure 2.2.1.[47]

[46] See, http://www.isorto.org/site/c.jhKQIZPBImE/b.2603295/k.BEAD/Home.htm
[47] See, http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-rto-map.pdf

Figure 2.2.1 Map of Organized Markets in North America (2009)



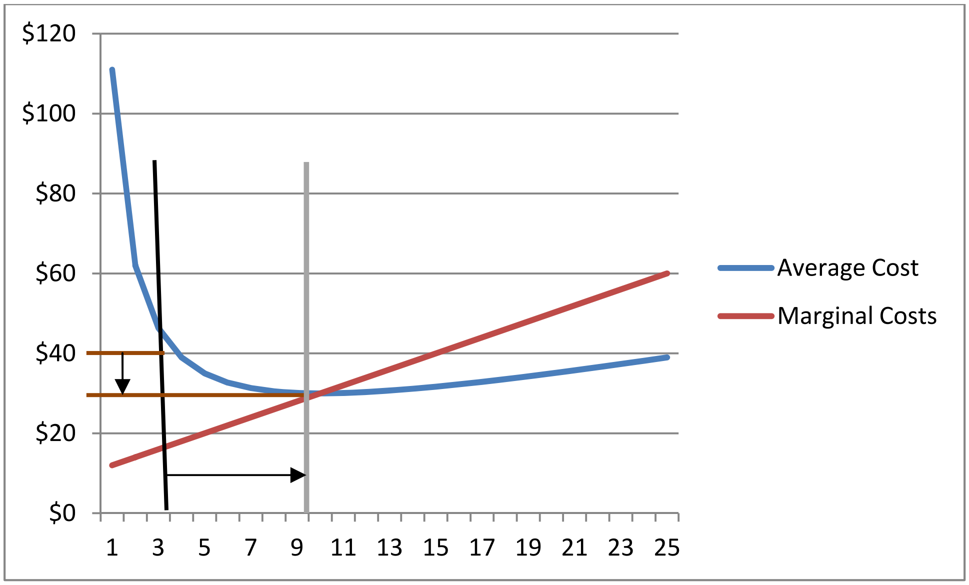
Independent System Operators claim extensive advantages over the traditional model of electrical utilities. These include: increased reliability, caused by economies of scale, better coordination and training; and decreased costs, due to the retirement of less efficient generators, increased investment and market participation, and more efficient dispatch. For example, since the implementation of the New York Independent System Operator, over 80% of the 7,314 MW of new generation has been located in the downstate region, and half in constrained load pockets. In this region, electrical prices fell by two percent from 2005 to 2008. The Independent System Operators also claim they provide increased flexibility in power scheduling, and increased utilization of transmission assets by using more accurate and instantaneous voltage metering (IRC, 2009).

There is evidence that in many markets that wholesale competition has in fact lowered electrical prices, especially in the presence of an Independent System Operator (IRC, 2009). The presence of a liquid electrical market allows for utilization rates for individual generators to increase, decreasing average costs, and for the development of higher resolution pricing both temporally and geographically.

The resulting markets have helped to provide clear signals about long-term pricing and to incent efficient generator construction. With market differentiation, new products have also developed, such as increased demand response capacity during peak-hours, and generator development in constrained areas. For instance in New York, generator availability increased by 7 percentage points, resulting in the equivalent addition of 2,400 MW of additional electrical capacity (IRC, 2009).

With a wholesale market, two short-term benefits may emerge. First, the industry wide short-run supply curve should shift down as utilities substitute using high cost units through trade. This trade allows utilities to maximize the use of their baseload units. Second, generator supply curves should move closer to marginal costs due to competition and away from supposedly sub-efficient supply curves set by regulators. To understand the benefits first consider a utility that has one generation unit capable of meeting load. The unit has a cost function equal to $100-q + q^2$. Figure 2.2.1 shows the average and marginal cost functions for this generator and illustrative inelastic demand. In order to recover costs for the generator, the utility receives the average cost. In a competitive market, the utility could dispatch the generator more often and operate the generator at the minimum of its average cost curve allowing it to trade the increased supply. As this occurs, the industry-wide short-run cost curve would shift from average cost to marginal cost. As a result price decreases, in this case from $40 to $30 per MWh.

Figure 2.2.1 Illustrative Generator Cost Structure ($/MWH)



These are only short-run outcomes, without long-term cost recovery, utilities may not have a sufficient guarantee to make investments in new plants and capacity, out of fear that they will not be able to recover fixed costs. This could drive up costs in the long-run as system load grows and utilities use expensive peaking units more frequently to satisfy long-term demand.

2.3 The FERC's Regulation of Horizontal Market Power

This section will review the FERC's protocols for regulating horizontal market power in the electrical industry. In certain jurisdictions, Independent System Operators and state regulatory commissions may also have regulatory authority, but not in Montana.[48]

The FERC regulates horizontal market power through a presumption of market power. A utility must apply for and be granted "market-based rate authority" in order to sell electrical products without oversight and regulation. A utility that is not granted market-based rate authority must sell power per

[48] The Montana PSC has virtually no interaction with, or authority over the conduct of wholesale energy providers in the state. The only exception is their jurisdiction over PPL's compliance with the Montana Renewable Power Production and Rural Economic Development Act.

the terms and conditions of a FERC tariff. The FERC began providing this authorization in 1988 to wholesale energy providers on a case-by-case basis, which allowed providers to sell energy, capacity and ancillary services without regulation by the FERC (FERC, 2007, 5). In making these determinations, the FERC used a four-prong analysis (FERC, 2007, 6):

1. Whether the seller and its affiliates lack, or have adequately mitigated, market power in generation;
2. Whether the seller and its affiliates lack, or have adequately mitigated, market power in transmission;
3. Whether the seller or its affiliates can erect other barriers to entry; and
4. Whether there is evidence involving the seller or its affiliates that relates to affiliate abuse or reciprocal dealing.

In 2004, the FERC clarified and further formalized its policies for granting market based rate authority.[49] In 2007, Order 697 refined the policies and established the following elements. Wholesale providers must make triennial filings showing that for their respective market that the pass both an (1) uncommitted market share analysis and (2) uncommitted pivotal supplier screen. The uncommitted market share analysis measures whether a supplier may have a dominant market position by measuring the amount of capacity that a seller owns in comparison to other sellers in the area after accounting for native load obligations and other commitments (FERC, 2007, 36). If the seller's concentration (market share) is greater than 20% percent than it fails the screen (FERC, 2007, 23).[50] The uncommitted pivotal supplier screen analyzes the ability of a seller to exercise market power unilaterally through a pivotal position in market. It is measured at the time of the Balancing Authority Area's annual peak load. If the FERC finds that the seller's uncommitted capacity is pivotal to meet that peak load condition, than the seller fails the screen. The pivotal supplier screen simply requires that the seller's capacity not be

[49]AEP Power Marketing, Inc., 107 FERC ¶ 61,018 (April 14 Order), order on rehearing, 108 FERC ¶ 61,026 (2004) (July 8 Order).

[50] The FERC does not engage in analysis about selecting the 20% threshold, only noting that "in market for commodities with low demand price-responsiveness like electricity, market power is more likely to be present at lower market shares" (FERC 2007, 51). Many commentators, including PPL, had pushed the FERC to use a 35% screen.

needed to meet Balancing Authority Area demand, after adjusting for committed capacity. In addition to the screens, the FERC has reserved the right to initiate investigations into market power, referred to as Section 206 proceedings from the relevant section of the Federal Power Act, or Delivered Price Tests, based on its review of electric quarterly prices filings by providers, other daily market price information, or tips and other sources of information.

The FERC interprets the failure of a seller to pass either preliminary screen as rebuttable presumption that the seller has market power. In such a situation, the FERC provides the seller the opportunity to propose mitigation or to file a Delivered Price Test to gain market-based rate authority in a particular market. The FERC also uses a Delivered Price Test to assess the impact of mergers, and as such is described in Appendix A of Order 592 (FERC, 1996), its merger analysis guidelines.

A Delivered Price Test is a misnomer, and simply an enhanced concentration measure. The test is conducted by adding in Economic Capacity that is available (not committed to native load) and has sufficient transmission to reach the candidate balancing authority area. The test is conducted in several market periods.[51] Economic Capacity is defined as capacity "whose variable costs are such that they could deliver electricity to a relevant market, after paying transmission and ancillary service costs, at a price close to the competitive price in the relevant market" (FERC, 1996, 68). With the FERC suggesting that transmission costs, derived from the Open Access Transmission Tariff, and specific plant operating data providing cost information are to be used to ensure that the capacity is "Economic" and able to compete at a series of test or market prices (FERC, 1996, 66). Herfindahl–Hirschman Index ("HHI") measures between 1,000 and 1,800 indicate a "moderately concentrated" market and HHI of greater than 1,800 indicate a concentrated market (FERC, 1996, 75).

[51] The periods are: super-peak, peak, and off-peak, for Winter, Shoulder, and Summer periods and an additional highest super-peak for the Summer. (FERC 1996, 60)

2.4 Montana Case Study

The expiration of the deregulation rate caps in Montana corresponded with the FERC's development of new market power regulations. This section will review PPL's market-based rate filing, and the FERC's review to understand its process, which lasted five years and was resolved by a federal appellate court.

The FERC originally granted PPL market-based rate authority in 1999, when its capacity was committed by contract to meet the MPC's loads through 2002. In the spring of 2004, PPL had to reapply for market-based rate authority under the FERC's new methodology.[52] PPL filed on November 9, 2004 the results of its preliminary screens (market share and pivotal supplier). With this filing, PPL argued that its 1,248 MW of capacity should be adjusted to 1,028 MW to account for actual seasonal hydroelectric capacity. PPL based its hydroelectric adjustment on the actual average production of its hydroelectric facilities. In the filing, PPL found market concentrations of no greater than 12.64% for several seasonal markets and found that 1,211 MW of extra capacity existed during peak demand in the NorthWestern Energy Balancing Authority Area. The finding implied PPL passed the pivotal supplier test, as this capacity was greater than unmet demand (PPL, 2004). Table 2.4.1 provides a comparison of PPL's assumptions in this filing with later revisions in the docket.

The FERC responded on March 25, 2005 that PPL's original filing was deficient, and in particular, did not appear to address the fact that much of Montana's electrical generation capacity, primarily the Colstrip Units, was already committed and should be excluded (FERC, March 2005). PPL responded on April 15, 2005 with updated analysis that made effectively the same findings as their original filing (see Table 2.4.1, 4/15/2005 filing). In particular PPL argued that the capacity owned by the other Colstrip owners was "uncommitted capacity" and should be included in the calculation.

[52] The complete record and all related filings can be retrieved on FERC's website by searching for any of the three docket numbers: ER99-3491, ER00-2184 and ER00-2185.

Table 2.4.1 Comparison of PPL's Concentration Calculation

		11/4/2004 filing, claiming only average on-peak hydroelectric capacity	11/4/2004 filing, adjusted for PPL's nameplate capacity	4/15/2005, PPL revised filing in response to the FERC[53]	9/1/2005, FERC Order finding PPL failed the screen
PPL's Generating Capacity	A	1,071	1,298	1,137	1,137
PPL's Native Load Proxy or Obligations	B	680	680	680	450
Other Uncommitted Local Generation	C	1,597	1,597	1,713	320
Simultaneous Import Limits	D	1,120	1,120	1,400	1,120
Total Competing Capacity	E: C+D	2,717	2,717	3,113	1,440
PPL's Uncommitted Capacity	F: A-B	391	618	457	687
Total Seasonal Uncommitted Capacity	G: E+F	3,108	3,335	3,570	2,127
PPL's Market Share	H: F/G	12.58%	18.53%	12.80%	32.30%

In response, NorthWestern Energy critiqued PPL's classifications and categorically alleged that PPL had market power and was using it to suppress competition and to raise prices in Montana.

> "The PPL Companies are not subject to any meaningful competition within the NorthWestern Energy Control Area *(Balancing Authority Area)*. In fact, PPL Montana has testified that, by virtue of owning 90% of the available electric generation within the NorthWestern Energy control area, PPL Montana has a competitive advantage over potential competitors. The concern over a competitive electric market has been the focus of comments from the Montana PSC, Montana Governor Schweitzer, and the Montana Consumer Counsel, which have all acknowledged that meaningful electric competition does not exist in Montana and that this threatens the economic viability of the state." (NorthWestern Energy, 2005) [54]

[53] The increases in rows C & D are not explained in PPL's filing.

[54] NorthWestern Energy also observed that they were "dependent on PPL to serve its default supply obligations" and that "PPL companies have used this dominant position to obtain a premium price for power sold to NorthWestern Energy and to suppress competition by aggressively intervening in NorthWestern Energy's resource plan and acquisition filings at the Montana PSC". (NorthWestern Energy, 2005)

NorthWestern Energy noted in particular that PPL had provided power from 1999-2001 for $22.5 per MWh and that they had raised the price to $32 per MWh in 2002, a 22% increase (NorthWestern Energy 2005, 27).[55]

On September 1, 2005, the FERC issued an order finding that PPL had a rebuttable presumption of market power and initiating a Section 206 proceeding (FERC Sept. 2005). In this Order, the FERC referenced analysis by its staff that concluded that PPL had market concentrations of 32.3% in certain markets, but did not produce the analysis.[56] In particular, the FERC found that the Colstrip Units should not be treated as uncommitted capacity, because the two dominant owners, Portland General Electric and Puget Sound Energy were net purchasers. The FERC also found that PPL's 230 MW of native load commitment with its marketing arm, PPL Energy Plus, to serve industrial loads was not a credible native load obligation or a commitment of its generating capacity (FERC Sept 2005, 13).

PPL responded with a Delivered Price Test on October 31, 2005, which was replaced due to errors two weeks later. This response included an offer to provide a 100 MW product at a price five dollars minus the Mid-C Price for 2007 and 2008 (PPL Oct. 2005, 11).[57] The long-term average quarterly MID-C rate when this product was offered was $50.6 per MWh (Figure 4.3.7). On May 18, 2006, the FERC issued an order terminating the Section 206 proceeding and granting PPL market-based rate authority, determining that it had rebutted the presumption of market power (FERC, 2006). The same day, the FERC issued a Notice of Proposed Rule Making on its process for determining market-based rate authority, which eventually resulted in Order 697. Shortly afterwards, on July 5th, 2006, PPL and NorthWestern Energy agreed to fixed prices and quantities for 325 MW of peak power and 175 MW of

[55] PPL responded to the NorthWestern Energy's filing, observing that much of its criticism originates in a desire to receive "cost-based" versus "market-based" rates.

[56] The key components of the FERC's analysis appear to be the reduction of PPL's native load commitments by 230 MW, and the available uncommitted market capacity to 1,440 MW.

[57] PPL did not provide any rational as to how they had selected the offer price.

off-peak power to begin on July 1st, 2007 ("The Seven Year Contract"), and to continue for seven years, with the contract quantities beginning to decline on July 1st of 2012 (PPL, 2007).

A month and a half after the FERC received notice of The Seven Year Contract they denied rehearing of their decision granting PPL market-based rate-authority. It this denial, the FERC specifically noted the existence of the Seven Year Contract as a factor that corroborated its earlier finding (FERC, 2007). The Montana Consumer Counsel appealed the FERC's decision to the 9th Circuit Court of Appeals, which denied the petition for review on June 8, 2009.[58]

2.5 Critique of the FERC's Review Process

The FERC's final decision in the PPL review is troubling. The FERC found that PPL failed its preliminary screen based largely on the fact that Colstrip generation was "committed" and thus not competing capacity and that the relevant market was probably not the entire NorthWest Power Pool. However, the FERC did not offer any affirmative explanation as to how PPL had mitigated these finding with its Delivered Price Test.[59] Instead, the FERC recognized PPL's 100 MW capacity offer as an effective mitigation of market power without making any specific technical finding that their offer did this. FERC did not address the potential cost associated with previous market power that was exercised by PPL from the period after the deregulation cost caps until the start of the contract (2002-2007), nor did FERC address what the process would be after the 100 MW capacity contract expired. This section will review these and other concerns with the FERC's process.

[58] Montana Consumer Counsel v. FERC, Nos. 07-73256, 07-73547, *et al.* (9th Cir. Jun. 8, 2009). The Montana Consumer Counsel, the Montana PSC, and REC Silicon (the largest industrial consumer) were joint parties in the proceeding. The 9th Circuit reaffirmed that the FERC is "afforded great deference" in determining whether a suppliers rates are just and reasonable.

[59] PPL had defined the NorthWest Power Pool as "loose power pool that allows for coordinated operations of the electricity system in the Pacific Northwestern portion of the U.S., British Columbia, and Alberta…transactions in the NWPP are centered around the Bonneville Power Administration and that much of the region's electricity production can move freely between the various control areas interconnected to that control area due, they claim, to the existence of a liquid trading point, i.e., Mid-Columbia." (FERC Sept. 2005)

In the case of PPL, the FERC's preliminary market screen worked. It signaled the FERC that PPL had the potential to exercise market power and that further study was warranted. However, there are problems with the screen as demonstrated in equation 2.5.1. An applicant only has to receive a result of less than 20% to satisfy the screen. With generation capacity fixed, the primary choice variable in the equation is the applicant's native load obligations, and an applicant that is close to the screen could decide to increase these obligations until it satisfied the screen. Calibrating this equation based on the FERC's September 2005 Order reveals a native load obligation threshold for PPL of 657 MW. A seller can thus use native load contracts to buy-down its capacity to a point that passes the screen, by entering into sufficient firm-supply contracts to be below the 20% threshold for the one-year test period reviewed by the FERC. In Montana, the availability of significant (325 MW) generating capacity that can choose a wholesale electricity supplier provides a liquid market for these buy down transactions.

Equitation 2.5.1 Pivotal Supplier Equation

$$\frac{\text{(Applicant's Generating Capacity - Applicant's Native Load Obligations)}}{\text{(Applicant's Generating Capacity - Applicant's Native Load Obligations + Other uncommitted generation + simultaneous import limits)}}$$[60]

The pivotal supplier test has similar equation structure, where an applicant only needs to show that there is sufficient excess capacity in the Balancing Authority Area to meet the loads, even by one MW. The pivotal supplier screen also considers the simultaneous import capacity as competing capacity, though this capacity must incur a transmission wheel or charge to reach the test Balancing Authority Area. When this capacity is removed, and the values from the FERC's Order finding PPL failed the screen, only 320 MW of uncommitted local generation remain in NorthWestern Energy's Balancing

[60] All values are calculated within the Balancing Authority Area in which the generation being evaluated is located.

Authority Area. For any uncommitted load value greater than 320 MW, PPL would fail the screen, or its capacity would be pivotal.

The historical development of the FERC's market power screen further illustrates these problems. During the FERC's development of Order 697, State Attorney Generals and Advocates[61] and the National Association of State Utility Consumer Advocates criticized the FERC's process. First, they suggested that FERC use game theory models to evaluate market power more effectively (FERC 2007, 69). The FERC rejected this position stating that:

> "Although game theory has been used in laboratory experiments and in theoretical studies where the number of players and choices available to players are limited, we do not consider it a practical approach for the volume of analyses we must perform, particularly since a vast amount of choices are available and many of those are unobservable. The data gathering and analysis burden imposed on sellers and the Commission would be overly burdensome and impractical." (FERC 2007, 70)

Second State Attorney Generals and Advocates pointed out that the FERC has never "systematically attempted to correlate the results of the pivotal supplier indicative screen, the market share indicative screen, or the DPT (including HHI results) with actual independently derived data and measures as to the existence of market power in any wholesale electricity market in the U.S." (FERC 2007, 56) Third, they noted that the courts had never certified the FERC's process as meeting the "just and reasonable" requirement of the Federal Power Act for evaluating market power (FERC 2007, 65).

The primary issue though is still one of whether, even with the Seven Year Contract, if there will be sufficient "uncommitted capacity" to deter the exercise of market power by PPL. This question solely rests, from the FERC's perspective, on PPL's market share which has two primary variable components: the relevant market (NorthWest Power Pool or NorthWestern Energy Balancing Authority Area) and

[61] New Mexico Office of Attorney General, Colorado Office of Consumer Counsel, Utah Committee of Consumer Services, Public Citizen, Public Utility Law Project of New York, Rhode Island Office of Attorney General, and Rhode Island Division of Public Utilities and Carriers.

what capacity is "uncommitted", or can compete against PPL. Increasing the size of the relevant market will water down PPL's market share, as will increasing that capacity that is defined as "uncommitted". In its September order, issuing a Section 206 proceeding, the FERC determined that PPL had not demonstrated that the NorthWest Power Pool was the relevant wholesale market (FERC Sept. 2005).[62] Implying that the relevant market, and where PPL should restrain their analysis, was NorthWestern Energy's Balancing Authority Area. PPL did restrain its Delivered Price Test to this market, but relied on transmission import capacity to create additional "uncommitted capacity". The FERC adopted this approach, which effectively increases the quantity of generation within NorthWestern Energy's Balancing Authority Area by the size of the transmission import limits, which are 1,342 MW-1,406 MW depending on season.

This is problematic because the costs of moving electricity, which the FERC fixes through Open Access, intrinsically create barriers to entry.[63] Chapter 4 discuses these mechanics in more detail, but a generator must incur costs of about $6 per MWh to reach NorthWestern Energy's Balancing Authority Area. Further, the FERC failed to explain, or analyze, why after incurring these costs that the capacity would be "competing" with PPL. The FERC's finding are also based on the HHI index, which as explained in Chapter 3, are not supported in the economic literature as a valid indication of market power in electricity markets.

The FERC's review resulted in a grant of market-based rate authority alongside an offer that PPL would provide a fixed amount of capacity at a discount from MID-C prices. While this approach may have mitigated PPL's market power, the FERC did not analyze whether the offer effectively mitigated market power, or whether the rates and terms of the deal were reasonable. It is unclear why the FERC

[62] The FERC's analysis relates exclusively to transmission capacity and does not mention cost.

[63] Consider two competing firms, with identical costs structures, but one firm must incur a transmission charge to sell energy. The result of the charge will be to raise the price of entry for the one firm, increasing the price by the amount if the charge from the normal equilibrium.

did not take the more conservative approach and deny PPL market-based rate authority and institute a fixed price tariff for PPL's wholesale transactions.

The negotiation of the Seven Year Contract provides a potential solution to PPL's market power, as it fixed a large quantity of generation at pre-determined prices. However, the price for this contract may have already reflected PPL's market power mark-up. It also represented a significant mark-up of the deregulation price cap, $32 per MWh, and built on subsequent increases. While the price did not have the shock value of those seen in clear exercise of market power, such as the $1,000 per MWh during the California Electricity Crisis, a small mark-up that is guaranteed for several years, will be more profitable than a short-term order of magnitude increase.

2.6 Conclusion

The structure of electrical markets experienced a profound shift after the implementation of Open Access. Across North America, most markets have been reorganized and operated by Independent System Operators who help to increase efficiency and to mitigate the exercise of market power through price auctions. The FERC has attempted to regulate market power, based on concentration measures. In the Montana market, the FERC eventually found that PPL had market power, but allowed the utility to contract for a long-term electrical product as a solution. This stop-gap measure did not address previous price setting behavior or create a long-term template for regulation.

3: *Modeling and Detecting Market Power*

This chapter will review market power theory and application (3.1), models for firm competition in electrical markets and the economic literature on competition in wholesale electrical markets (3.2), suggest game theory approaches that regulators could employ to detect market power (3.3), and discuss the implications of structural changes in the regional wholesale electricity market and the role Independent System Operators could play in helping to maximize efficient market outcomes (3.4).

3.1 Market Power Theory and Structure

Market power is the ability of a firm to alter the market price of a good or service in a market through unilateral action. Firms gain market power through strategic positioning in which they control a unique asset (such as a rail line, electrical transmission facility, or a patent) or concentration, which is marked at the extreme by a monopoly. Firms' most commonly exercise market power through price setting, though a firm may exercise its market power through actions that indirectly increase price. Such as; holding on to key industrial sites in order to erect barriers to entry, or strategically acquiring patents and their development companies to maintain technological dominance. Firms may also invest heavily in employee retention, lobbying, and marketing to maintain a strategic position.

It is often difficult to identify market power due to actual differences in marginal costs between firms and the general elasticity of demand. For instance, a gas station that charges an extra five cents per gallon at the end of a road may not be pinching consumers, but instead just recovering the additional cost of transporting gas to the station. Additionally, consumers will quickly substitute to buying their gas when they go to town if the station raises price above a reasonable mark-up for the station's increased costs. However, with inelastic demand the potential for market power increases. In an industry with minimal elasticity, a relative increase in price will result in a relative decrease in demand. High elasticity reflects unwillingness or an inability for consumers to reduce demand for corresponding changes in prices. Under these conditions, increases in price typically offset the lost quantities.

The potential capacity for market power in electrical markets is high. The demand for electricity is highly inelastic, if not perfectly inelastic, at the moment of consumption and relaxes only slightly over long periods. Inelastic demand implies that demand is determined exogenously from price, though it is predictable with certain distributions in electrical markets. Factors that influence demand include the hour of the day, weekends versus workdays, holidays, seasons, weather, and temperature. Utilities carefully scrutinize these factors to predict demand.

The electrical industry was also historically organized as a natural monopoly. Consequently the industry designed generator development to meet demand precisely and to follow and respond to the seasonal and diurnal nature of demand. This resulting specialization provides generators unique niches, which can have value significantly over their marginal costs and make the generator strategic in certain seasonal conditions. There are also extremely high barriers to entry, for instance it takes three to ten years to permit and construct new generation.

Because of inelastic demand in electrical markets, the capacity for market power is highly dependent on the distribution of demand. Fehr and Harbord (1993) develop a formal model that describes firm strategies under different demand conditions. Their model shows that under low-demand conditions that marginal cost pricing is a possible outcome, as generators will offer marginal costs as their profit maximizing strategy to capture as much demand as possible. However, under high and variable demand conditions, a firm's profit maximizing strategy it to be the price setting generator in the market.   These outcomes will result in prices that significantly depart from marginal costs, even when several firms are "competing".

Given the historical structures of vertical integration, a firm can be both a producer and supplier of electricity. This structure, under certain conditions, creates elastic demand as an individual firm chooses between deploying its own generation to meet load, purchasing a portion from the market, or purchasing from the market and selling its generation into the market. It is unclear if vertically integrated firms have incentives to participate in the wholesale electric market with rate-based generation. For instance, the Montana PSC has no formal policy to evaluate NorthWestern Energy's market transactions to understand if they are efficiently selling and buying power in the wholesale market.[64] A firm, which is entitled to fixed cost recovery with rate-based assets, may be hesitant to make market sales which could benefit consumers, due to risk aversion and a lack of a profit incentive.

The economic literature analyzes strategic bidding behavior of firms in electrical markets (Holmberg and Newberry, 2010). Most of the analysis focuses on organized markets, where an Independent System Operator conducts an auction to determine the market price based on suppliers' and producers' respective offer curves. In organized markets producers submit offer curves specifying the price and quantities they are willing to supply. Depending on the market, these may be either flat (specifying a single price and quantity) or increasing. Suppliers, the buyers of electricity, submit their bid curves specifying the quantity and price of electricity they wish to buy. The Independent System Operator uses one of two primary auction formats, either uniform price, or pay as bid, to determine the market price and quantities.[65] As suppliers may own capacity sufficient to cover their demand obligations for some periods, and as demand (certain industrial loads) may participate in these markets, demand is often elastic.[66]

[64] Personal conversation with Will Rosquist, Montana PSC.

[65] A uniform price auction provides all market participants the market clearing price for their quantities, regardless of their offer curve, for those quantities needed to clear the market at the determined price. A pay as bid auction provides all market participants their bid price, if their quantity is needed to clear the market.

[66] In Great Britain, 2,000 MW of the 50,000 MW of total demand is load that directly participates in the market. (Holmberg and Newberry, 2010).

The two primary auction formats used in organized markets differ fundamentally from the pricing structure in the Pacific Northwest, which is determined through rate-basing and bilateral transactions. There is a Dow Jones index for the region, known as the MID-C. The MID-C index reports ex ante volume weighted average price outcomes of specifically defined bilateral transactions from physical contract points centered around the Columbia River on the border of Oregon and Washington.[67] There is robust trading in this region, in excess of 70,000 aMWs for short-term transactions, which may create regional price uniformity as some bilateral contracts are based on the ex-ante MID-C index price.

There is little treatment in the literature regarding market outcomes in regions dominated by bilateral transaction, such as the MID-C. However, one analysis of bilateral contracting found significant price heterogeneity (Comes, Kahn & Belden, 1996). The authors analyzed a series of bilateral contracts that occurred before the FERC's implementation of Open Access. Contract prices were adjusted for fourteen independent variables ranging from input factor costs (fuel and capital) to local cost of living adjustments. The results show wide disparities in normalized pricing. For instance, amongst 20 contracts for electricity from gas-peaking resources the study found a price spread of 2.1 from the lowest to the highest price contract after their normalization. In one case, two similar generation units that sold to the same utility had a price differential of 1.4. The study concluded that the lack of price convergence for a perfectly homogenous good indicates that bilateral contracting was potentially uncompetitive.

3.2 Economic Literature Review

This section will review the economic literature describing outcomes in electrical markets, and review the Cournot and Supply Function Equilibrium models.

[67] See, http://www.djindexes.com/mdsidx/?event=energyMidColumbiaH. The physical contract points are the following resources on the Columbia River: Columbia, Midway, Rocky Reach, Wells, and Wanapum/Vantag.

Great Britain's electrical market was the first deregulated electrical market to be studied in detail. The seminal paper (Green & Newberry, 1992) applied a Supply Function Equilibrium model to estimate the price and quantity outcomes in the British electrical market. Similar studies have now been completed for many markets including California (Borenstein, Knittel and Wolfram, 1999), Germany (Musgens, 2006), Pennsylvania (Mansur, 2007), Texas (Hortacsu and Puller, 2008) and Spain (Ciarreta and Espinosa, 2010), to name a few. Most of these markets are organized with day-ahead auction mechanics determining the price.

Economists widely recognize that concentration measures such as the HHI index fail to capture the dynamics of electrical markets (Borenstein, Bushnell & Knittel, 1999). By excluding certain factors, they are typically suited only to screen market power potential. In particular, they fail to capture three important incentives: the incentives of producers, which can differ between firms; the elasticity of demand, which in electrical markets can be highly inelastic, providing significant opportunities for market power; and potential equilibrium changes, such as competitor expansion or the development of competition (Bornstein, Bushnell & Knittel, 1999).

Economists have, however, made substantial progress in developing more suitable models for understanding market power in electrical markets (Holmberg and Newberry, 2010). There are three standard industrial organization models for firm competition - Bertrand, Cournot, and Supply Function Equilibrium. The two primary models deployed in electrical markets are the Supply Function Equilibrium model and a Cournot model (Willems, 2009). The Bertrand model (which assumes that firms compete in prices) is not generally applied to electrical markets for two primary reasons. First, firms are limited in their range of production quantities, and significant marginal cost markups are observed. And second, firms are not able to capture the entire market with a single price, due to capacity restrictions (Bornstein, Bushnell & Knittel, 1999). An oligopoly competing in prices (Bertrand), will generally set price equal to marginal costs, whereas quantity competition (Cournot) will typically see a mark-up over marginal costs (Fehr and Harber, 1993). The Supply Function Equilibrium model is generally the preferred approach, as it mimics the offer curves in many organized markets bid by producers (Holmberg and Newberry, 2010). The following sections will present both models, and examples of their application.

Cournot Model

Cournot modeling assumes quantity competition where the firm will select the quantity to produce, conditioned on available information about the market, and then receive profit ex post based on the market quantity supplied. Firms thus highly condition expectations on other market participants' behavior, their marginal cost structure, and demand elasticity. In electrical markets, firms are constrained in quantity selection by the characteristics of their generators, their total capacity and which units they can vary production of. Generally, Cournot competition provides that the market price the firm receives will generally increase as the firm decreases the quantity it supplies to the market. This condition implies that firms will have an incentive, subject to their cost function and the slope of the demand curve, to decrease quantity in order to increase the market price. This behavior is known as capacity withholding.

The Cournot structure can be seen by constructing the Cournot Duopoly solution. Multi-firm solutions can be defined, but add complexity. For a given demand level (D), and cost (C). Each firm (i and j) will select its quantity (q_i or q_j) conditional on the other firm's quantity selection, such that firm profits (π) for firm (i) are $\pi_i = pq_i - C_i q_i$. Each firm contributes to total demand, so $q_i = D - q_j$ which can also be described as the residual demand faced by firm q_i, $D_r(p)$. The profit function can thus be rewritten as $\pi_i = p(D-q_j) - C_i(D-q_j)$. The first order conditions (dq_j/dp) are: $D-q_i-C_i$, which results in the best response functions for firm "i", of $q_j = D-C_i$. Under simplified assumptions, Cournot competition can be reduced to

Equation 3.2.1, which specifies that the price (p) will be determined by the firm's costs ($c_1^{'}$), demand elasticity (ε) and market share (s_i), (Willems, 2009).[68]

Equation 3.2.1 Cournot Equilibrium

$p\text{-}c_i / p = -s_i / \varepsilon$

With constant marginal costs and no fringe suppliers, Equation 3.2.1 can be used to calculate market prices. The firm's profit function can provide individual firm quantities. If a firm participates in a power exchange or organized market, where the firm can submit a bid function, there is a single market price (p) determined as a function of the other firm's quantities (q_j). As such, each fringe supplier will face a demand curve ($D_i(P)$), which is equal to the $D_r(P)$ minus the sum of the other Cournot fringe suppliers. In the electrical industry, a constant elasticity demand function often determines price ($Q=p^{\varepsilon}$) which is anchored at an observed market outcome.[69] Another formulation for demand is to assume that it is time varying in accordance with a certain distribution, and may be subject to certain shocks (ε), and not known ex ante by firms.

Electrical markets seldom contain constant marginal cost, and often exhibit "hockey-stick pricing" with flat constant marginal costs for large portions of demand, and than steep almost vertical portions. These structures cannot be represented with equations. The flat portions also present the pontential for multiple equilibri. Nash-Cournot equlibrium cannot be solved, and have to be calculated through a grid search mechanism, where each firm's response is calcualted iteratively until the mutal profit maxamizing outcome is determined. Some authors have approximated the step-like supply functions into smooth functions (Green and Newberry, 1991), but others (Fehr and Harber, 1993) have questioned this approximation. These approaches raise additional questions about whether generator

[68] Willems, 2009 assumes that the inverse demand function depends on total production.

[69] Borenstein & Bushnell, 1999, calculated anchors for each demand level they analyzed. For instance, for the 150th highest demand hour the anchor was $93 per MWh. For each demand elasticity they calculated (.1, .4 or 1) the demand function was assumed to pass through the relevant anchor point.

strategies will differ if they can provide a smooth bid schedule or a continous linear bid schedule in organized markets.

The application of the Cournot model to the California electrical market by Borenstein and Bushnell (1999) also provides the formulation for the competitive fringe. In that case, the competitive fringe represented several categories of producers, including price-taking qualifying facilities, and a fringe outside and inside California (Mexico, the Pacific NorthWest, California, and the SouthWest) subject to certain transmission constraints (TR). The study accounts for the effect of the price-taking fringe by subtracting aggregate supply of these firms from market demand, which provided a residual demand curve ($D_r(P)$) that was faced by the Cournot competitors, such that ($D_r(P)$) = $D(P) – S^f_{CA}(P)$-MIN($S^f_{MX}(P)$ – MIN($S^F_{MX}(P)$,TR_{MX})- MIN($S^F_{NW}(P)$, TR_{NW}) – MIN)$S^f_{SW}(P)$, TR_{SW}). The resulting residual demand was more price elastic than market demand. Borenstein and Bushnell, 1999 applied discrete quantities of supply from the competitive fringe, subject to the applicable transmission constraints, to determine price and quantity outcomes in the market, based on each Cournot competitors best response function.

The equation can also be formulated for a competitive fringe with a specific supply schedule (Joskow and Kahn, 2002), such that $D_r(P)$ is equal to $D(P)-Q_f$. Q_f is the inverse demand of the fringe, which for linear demand would be (P-b)/m (b is the intercept and m is the slope parameter). The Cournot duopoly profit conditions with a competitive fringe can thus be represented as $\pi_i= p[D-q_j-(P-b)/m)] – C_i[D-q_j-(P-b)/m)]$.

Borenstein and Bushnell’s (1999) Cournot model shows equilibrium prices, even for elastic demand, far greater than marginal costs. They also calculate concentration measures and the Lerner index, which shows a negative relationship over anchor demand levels. Thus for the California market, higher HHI indices (which in the FERC’s view correspond to market power potential) actually produce lower Lerner index values, a direct measure of market power markup. The effect is likely due to the influence of the competitive fringe, which maximizes participation at high demand levels, lowering the concentration index, but giving the Cournot competitors the capacity to significantly raise prices through tacit collusion.[70] It also shows that the as a function of the Lerner Index, that the HHI values are effectively meaningless at describing firm markups.

Supply Function Equilibrium Model

The Supply Function Equilibrium model offers another approach to modeling firm behavior (Klemperer and Meyer, 1989). The model proposes that firms may provide a price and quantity relationship as their strategic choice variable. The model typically assumes that firms have knowledge of the other their competitor's costs and residual demand.[71] For an individual firm (i), the profit maximizing equation is: $\pi_i = p[D - q_j(p)] - C[D - q_j(p)]$, as specified by Newberry (1998) for a firm with non-decreasing marginal costs in two firm competition. The specification differs from Cournot as firm quantity is now dependent on price. Thus, a firm's profit maximizing pairs can be described as a supply function ($q_i = S^i p$) which provides first order conditions (dq_j/dp) of $[q_i/(p - C'(q_j))] + D_p$, yielding a symmetric solution for both firms i and j. Firms can thus calculate their optimal price mark-up for each outcome by applying the monopoly mark-up rule or Ramsey pricing to the elasticity of its residual demand (Υ_i^{res}), which is provided in equitation 3.2.2 (Holmberg and Newberry, 2010).

Equation 3.2.2 Supply Function Equilibrium Mark-up Rule

$$p - c_i^{'}(q_i(p)) / p = 1/\Upsilon_i^{res}$$

The Supply Function Equilibrium Model provides significant insight into firm behavior in electrical markets, as it replicates the bid-curve offer strategy provided by firms in most electrical markets. The model is generally recognized to reflect the bid-curve producer offer strategy offered in most organized

[70] One important weakness of the Cournot model is that it does not capture collusion incentives. Firms may be able to coordinate supply in a manner that further increases profits, and likely price, through collusion (Borenstein, Bushnell and Knittel, 1999).

[71] Holmberg and Newberry, 2010, review alterations based on asymmetric information conditions.

electrical markets, which allows for a direct comparison of modeled firm specific Supply Function strategies to its' offer curve. For instance, Hortacsu and Puller (2008) calculate the Supply Function Equilibrium for firms in Texas electricity spot market and compare these results to actual firm bidding.[72] The market employs a multi-unit auction, replicating the Supply Function offer curve, with participants behaving as producers or suppliers depending on the market equilibrium, as they have both supply assets and native load obligations.

The Supply Function Equilibrium model can also incorporate bilateral contracts. The formulation, developed by Newberry (1998) represents the contract as a sale of a fixed amount of electricity (x_i) at a price of "f" per unit, such that the profit function for firm i, is: π_i=p[D-q_j(p)] –C[D-q_j(p)] +(f-p)x_i. For constant marginal costs, Newberry (2008) identifies three outcomes for firm strategies: (1) the firm will use the pool to fulfill its contract, under which they will find it profitable to drive the pool price down as they will be net buyers in the pool; (2) that they will just produce at the contract quantity, and not use the pool market; (3) that they will produce above the contract quantity, and act to drive the pool price up.

Modeling Implications for Detecting Market Power

The Supply Function Equilibrium Model and modified Cournot models provide an instructive perspective on applying economic theory to understand firm behavior and the potential for market power in electrical markets. However, they do not provide a *per se* test for whether market manipulation has occurred. That is, the models do not provide an absolute conclusion that a firm does or does not have market power. As such, one of their primary applications is to instruct how to conduct auctions, typically on a daily basis, by the Independent System Operator to minimize the influence of market power and maximize the benefits of competitive outcomes (Holmberg and Newberry, 2010).

[72] Sioahansi and Oren (2007) complete a similar study of the Texas market, with different assumptions about information symmetries between firms.

Though the models lack a *per se* test for market power, their outcomes have been benchmarked against empirical results (Sioshansi, 2006 and Willems, 2009). The benchmarking provides support that economic models can be effective in modeling actual outcomes.

The literature offers insight on how to achieve marginal cost pricing in organized electrical markets. Marginal cost pricing can be induced as a dominant strategy by separating the received price from the bid price, under certain conditions (Vickrey, 1961). This pricing independence eliminates the ability for a generator to influence its own payoff. Given the fixed costs present in an electrical industry, a generator will prefer to participate in the market at its marginal cost, relative to not participating. The result, with competition, is that a generator will bid its marginal cost to maximize the probability that it is selected to participate in the market and avoid the negative marginal costs associated with not participating in the market (Fehr and Harber, 1993).

A primary outcome from the development of the modeling literature is the successful detection of capacity withholding. Mansur (2008) found that two firms decreased output by 13% between the summer before and after electrical restructuring. These same two firms had markups from their net position to their market price markup. Both factors are consistent with their exercise of market power, which resulted in an increase in retail electrical prices by $1.6 billion from the perfectly competitive outcome. Wolak (2001) identified similar behavior in the Great Britain Electrical Pool Market.

The price to marginal cost markup or Lerner Index, provided in equation 3.3.3, is another approach to understanding market power. The test compares the actual marginal cost of production to the observed market price. Mark-ups greater than zero indicate some level of market power. The difficulty with the price mark-up test is establishing reasonable marginal cost estimates for the market, though this problem exists for game theory models as well. Further complicating marginal cost determination is the difference in long-run marginal and short-run costs depending on assumptions about long-run quantity supply associated with fixed cost recovery (or generator investment). There are also negative marginal costs, such as with wind generators which receive tax credits based on production, and non-linear and temporal dynamics from start-up costs related to cycling down base-load generators. One caution with using the Lerner index is that in markets with a single price auction, generators with low marginal costs may have high mark-ups even if they are bidding their marginal cost.

Equation 3.3.3 Lerner Index

(P-C)/P[73]

There are several approaches for identifying marginal costs, even when explicit cost information is not available. One approach, developed by Ciarreta and Espinosa (2010) was to compare the difference in mark-ups of large firms to small firms in the Spanish Electricity Auction. They find that for a number of conditions, the two large firms in the market consistently hold their offer curves to the left of the synthetic offer curve that they develop. This finding implies capacity withholding by the firms and the exercise of market power. Another approach, by Musgens (2006) was to develop a dispatch model for the wholesale German electric market to simulate marginal costs. The model provided simulated marginal costs based on actual generation information, which was then compared to observed market prices. The model thus provided a test for whether market power was occurring in the market if observed prices were higher than modeled prices. The period of analysis captured a period of industry concentration and corresponded to an increase in the marginal cost markup.

At least two authors have found high Lerner index values in the California electrical market, Bornstein and Bushnell (1999) and Joskow & Kahn (2002). Bornstein and Bushnell (1999) derive the marginal cost values from pricing models, with the mark-up determined from the calculated Cournot

[73] The reference price refers to the market clearing price.

equilibrium, as discussed earlier. They found positive Lerner index values in all periods, though they looked only at high demand periods. During peak demand periods, the Lerner index is as high as 99% above the Cournot equilibrium. Joskow and Kahn (2002) develop the competitive price benchmark based on the short-run marginal cost of the last unit that clears the market in each hour, which they identify as a natural gas generator. Using publically available heat rate information, they reconstructed marginal costs at a monthly average resolution for key periods of the so-called California Electricity Crisis. These prices include several factors that had been advanced as causing the crisis, namely increases in gas prices, increased demand, reduced availability of imports, and higher emission prices. With the inclusion of these factors, they still find prices above predicted market clearing marginal cost levels, implying an exercise of market power.

3.3 Approaches to Using Game Theory for Regulating Market Power

The previous section describes how game theory based models are being used throughout the economic literature to understand firm behavior in electrical markets and to test for market power. The models are dynamic and can explain a firm's strategic behavior and incentives, which are not captured by concentration measures like the HHI. This section will explore specific applications of game theory techniques to market power regulation.

Supply curves for individual firms, or markets, provide a wealth of information for regulators. The supply curve in the electrical industry typically consist of a series of baseload generators with constant marginal costs followed by peaking generators with higher and increasing marginal costs. As a result, shifts in demand can significantly increase price, especially during high-demand periods, as the peaking generator clears demand. As such, the slope and composition of the supply curve is a key characteristic in determining whether a firm will be able to unilaterally raise prices. Under most system conditions, it may be that the firm has minimal capacity to raise prices. However, when resources are limited (such as with low spring runoff), or demand is high, a firm may have significant unilateral pricing power. This sleeping capacity, in part, caused the California Electricity Crisis from June of 2000 to June of 2001 (Joskow, 2002).

Developing an understanding of supply curves is not a novel idea for detecting market power. Hunger (2003) suggested the use of supply curves to aid merger analysis in detecting the convergence effects of electric and gas mergers.[74] Hunger, a FERC staff member, suggested examining the industry-wide supply elasticity to measure a firm's potential to exercise market power. With higher more inelastic demand - the slope of the supply curve at the market-clearing price - generators would have a higher capacity to raise prices.

The crux of supply curve analysis is generating realistic marginal cost estimates or supply curves. Regulators typically gain accurate information about facility costs and can calculate marginal cost information. For instance, with both Spion Kop and the Dave Gates Generation Station the Montana PSC has access to detailed cost estimates for facility costs at the vendor level.[75] If regulators do not have specific marginal cost information, they could develop proxies using standard input cost information (fuel, capital and generators). Using assumed heat rates and known capital costs, regulators could at least estimate marginal cost information, such as Borenstein and Bushnell (1999) did.

There are also several off-the-shelf models that contain supply curves produced by reputable vendors.[76] These models use methods similar to Musgens (2008). These proprietary software models

[74] The significant growth in gas fired electrical generation capacity has led to vertical cross-industry market power concerns, as owners of upstream gas assets may be able to restrict supply or increase price to benefit their downstream gas-fired electrical generations benefit.

[75] Some of this information may be provided under a protective order, but it is still available to staff. Specifically, the Turbine Supply Agreement was provided in the Spion Kop Docket (D2011.5.41), which discloses the exact price paid for the wind turbines. See, http://psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2011-5-41IN110919523610.PDF

[76] Two widely used energy models are PROMOD (See, http://www.ventyx.com/analytics/promod.asp) and AURORAxmp (See, http://epis.com/company/).

contain supply curves and operational constraints to models and forecast market outcomes. Utilities use the models in integrated resource planning, and to optimize their trading and dispatch activities (PacifiCorp, 2011). Regional electric planners also use these models to understand system congestion, and have specifically constructed supply curves to understand import and export flows from adjacent coordination councils (WECC, 2011).

One application of using supply curves is Competitive Residual Demand analysis, developed formally by Gilbert and Newberry (2008). They proposed it as a tool to aid regulators to understand the market power implications of mergers. Their work looks only at hypothetical markets and does not formally introduce any formal tests for determining "trigger" residual demand slopes. Competitive Residual Demand assumes that demand is fixed in time at a predetermined market level or several levels. The residual demand is then the remaining wholesale market demand after removing the aggregate uncommitted supply from all other firms, computed at each price for the firms. The authors suggest using "industry standard marginal cost information" to determine the market clearing prices for the firms, assuming that all other firms behave competitively, by producing at their marginal cost.[77]

A distilled approach is the Residual Supply Index, which is similar to FERC's pivotal supplier test: $RSI=(\sum S)/D$. Where RSI is the index value, S is the sum of all generation offered by the non-candidate generators and D is the demand for the period. An RSI value of 1 is equivalent to the remaining supply being able to exactly meeting demand, without the candidate generator. The California Independent System Operator considers the market as reasonably competitive if the RSI value is greater than 1.2 (Shukula 2011), whereas the FERC's delivered price is effectively looking for any value greater than 1.

The Supply Function Equilibrium Mark-up Rule, equation 3.3.2, offers a final approach. It presents a firm's mark-up as a function of the elasticity of residual demand. For high residual demand

[77] As an alternative to strict marginal costs, the authors consider using a "mark-up" on marginal cost.

elasticity, the firm's mark-up potential is small, and it has little market power. Calculating the elasticity of residual demand is not simple, as it depends on the supply functions of the other firms in the market and is potentially unique for each demand level. However, with marginal cost information and the type of native load and committed generation information that firms already supply to the FERC, regulators could calculate residual demand for discrete demand levels.

Regulators can also apply the price-cost mark-up test to prices using average costs to determine if a generator is exercising market power. However, the test may not be effective in many wholesale markets which employ uniform price auctions in which all generators receive the market clearing price. The test may still provide some indication of market power or auction efficiency. In at least one case, the price mark-up test, and the residual supply index have shown the potential for market power where the HHI index did not. In a study of India's electrical market, Shukula et al. (2011) found that except in two regions, the HHI index did not indicate market concentration. However, the very simple Residual Supply Analysis indicated that all suppliers were pivotal in all markets and that observed pricing significantly departed from long-run marginal costs in all regions.

When marginal cost information is not available, a similar compensating variation test may provide equivalent insight. Chapter 4 contains such an analysis comparing the premium NorthWestern Energy's customers pay over Idaho Power's customers. This test illuminates how specific regulatory changes, in this case the lifting of price caps on a dominant wholesale supplier, impact electrical prices. Its value is ex post, but it also provides a macro tool for regulators to watch for potential market power and to test the effectiveness of regulatory structures. Given similar regional supply structures, as with Idaho and Montana, tracking price spreads between two regions could indicate market power.

This section identifies that there are economic models available to regulators that can help to understand firm incentives to exercise market power. Each of these approaches provides an opportunity for the FERC to establish methods based on economic principals to understand firm incentives. Marginal cost estimates form the basis of Lerner Index calculations, and are critical to instructing game theory models and understanding industry outcomes. Regulators have access to this information through several formats and can employ it to develop supply curves to understand firm incentives, without calculating Cournot and Supply Function Equilibrium solutions.

3.4 Market Structure and Changes in the Pacific NorthWest

In order to more effectively regulate market power regulators should consider regulating market power at the market structure level. This would follow many of the reforms discussed in Chapter 2, accelerating the Independent System Operators that would operate an organized market. Efforts to form a regional transmission organization in the western United States were highly politicized and have since ceased.[78] These entities, as independent bodies, monitor the markets and can institute reforms to their auction strategies to ensure that there is no market manipulation. Auctions with a sufficient number of participants also deter the exercise of market power by using auction structures that condition competitive outcomes.[79] This section will review the reasons for creating an organized market in the Pacific NorthWest and two specific dynamics that are shaping the market: over-generation and increased reliance on the wholesale market.

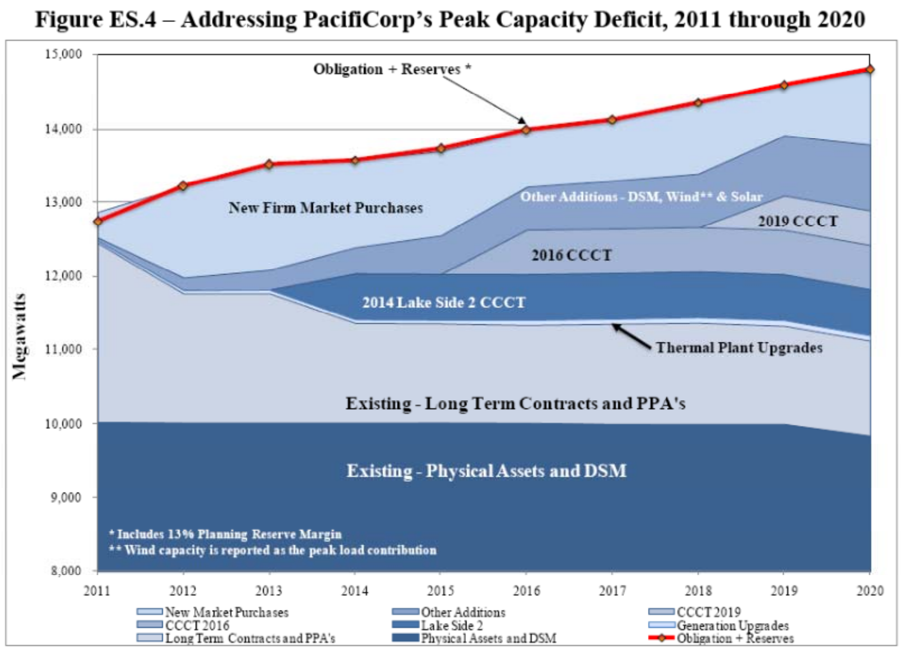
Regional utilities are beginning to turn to the wholesale electrical market to meet retail load obligations as a source of default supply. PacifiCorp is expecting to get 1,240 aMW of its retail need in 2012 from the market (PacifiCorp, 2011). Similarly, Idaho Power is looking to the Pacific Northwest MID-C market to provide 450 aMW of its need from 2015 forward (Idaho Power, 2011). This planning

[78] One of the most recent efforts was the formation of Grid West by BPA, Idaho Power Company, and PacifiCorp, see FERC Docket EL05-106-000, which ceased in September of 2005.

[79] Holmberg and Newberry (2010) provide an extensive review of the auction literature regarding electrical markets, which includes an important discussion of the tradeoffs between the two primary auction formats (single price, and pay-as-bid).

reliance is shifting the vertically integrated utilities in the region to a hybrid-deregulation approach. Under this model, they will utilize their long-term rate-based assets in conjunction with significant amounts of market purchases to meet their retail load obligations. Figure 4.4.1 shows the forecast vertical composition of PacifiCorp's resources to meet retail load obligations (PacifiCorp, 2011).

Figure 3.4.1 PacifiCorp's Proposed Resource Stack (PacifiCorp, 2011)



Increased wind generation capacity, now almost 5,000 MW, is contributing to increased market transactions.[80] Given the variable nature of this resource, utilities will likely find that regional diversity will result in hour-to-hour market transactions to help absorb periods of high-generation and to off-set periods of low generation. For several utilities by 2012 their minimum system load could be met significantly by wind energy, and will require that they either sell electricity or cycle down baseload coal generators, which create negative marginal costs. For instance, Idaho Power is expecting to have 765

[80] Installed capacity was just at 1,000 MW in 2005, and will top 6,000 MW if not 7,000 MW by the end of 2012 (NW Council, 2011).

MW of wind on-line at the end of 2012, with a minimum load condition of less than 1,100 MW and 1,118.2 MW of baseload coal capacity.

The increased dependence on the wholesale electricity market by regional utilities raises market power and efficiency concerns. Bilateral negotiation can be tedious and will result in inefficient transactions, which create market power opportunities. They are also slow and can create reliability events if system dispatchers are not able to coordinate quickly.[81] Often, instead of negotiating the real value, they may just default to a market index. This process creates false signals about the actual market value and may undermine two of the primary benefits of wholesale electricity markets. First, that market determined prices will provide signals for the timing and magnitude of investment by firms. And second, since firms have no influence over price in competitive markets, their only route to earning higher profits will be through in investment in cost-reducing technologies (Wolak, 2001).

One cause of market power is information asymmetries, which could be occurring in the west. Large sophisticated utilities, such as PacifiCorp, are in an advantageous position to understand the market behavior and to expend resources to forecast market outcomes and take advantage of them. PacifiCorp has 2,134 MW of wind energy spread from Wyoming to Washington, representing one-third of the region's total capacity. With each plant comes climatic information and detailed operational information that PacifiCorp can use to forecast both the production of its resources and others'. Such detail could provide PacifiCorp an informational advantage which they could use to exercise market power.

Mitigating information asymmetries and delivering competitive outcomes in electrical markets is the province of Independent System Operators. These entities can function without asset divestiture

[81] For instance, the Western Grid Group documents an event in February 2008, which resulted in the loss of over 2,500 MW of generation in the western interconnect that could have been avoided with an Energy Imbalance Market. See, http://www.westerngrid.net/2011/07/how-a-westwide-eim-helps-reliability/.

and provide a comprehensive structure to enhance regional reliability and maximize the benefits from competitive trade between utilities in the region, well minimizing the influence of market power. With the growing reliance of the wholesale electrical market to provide resource balancing and meet average needs, regulators should aggressively encourage the development of organized markets in the region to aid reliability and minimize market manipulation.

3.5 Conclusion

The economic literature offers a number of tools and methods to evaluate market power and generally shows that concentration measures are not effective tools. Regulators could significantly improve market power regulation by looking at marginal cost structures and industry supply curves in determining whether to grant market-based rate authority. Auction structures and forward contracting also provide tools to mitigate market power and should be considered as additional solutions.

4: *Montana Electrical Industry Structure*

This chapter reviews the structure of Montana's electrical industry, based on data from the Energy Information Administration, NorthWestern Energy, the FERC and the Montana PSC. The chapter is divided into six sections, which track different components of the structure of the Montana wholesale electricity industry: Aggregate Price and Demand (4.1), the Organization of the Transmission System (4.2), Wholesale Market Activity (4.3), Generation Capacity (4.4), NorthWestern Energy's Supply Position (4.5), and Analysis and Conclusions (4.5). The section will advance three methods for understanding PPL's market power. First, it will perform a compensating variation analysis to understand the relative welfare costs of the deregulation of the Montana electric industry (4.1). Second, it will use ex post information about the market to approximate Lerner Index values, or cost mark-ups (4.6), and estimate revenue and profit for PPL (4.3). Third, it will develop a Montana equilibrium model, based on the economic models discussed in 3.2, to understand the relative incentives of PPL and market power within the market (4.6).

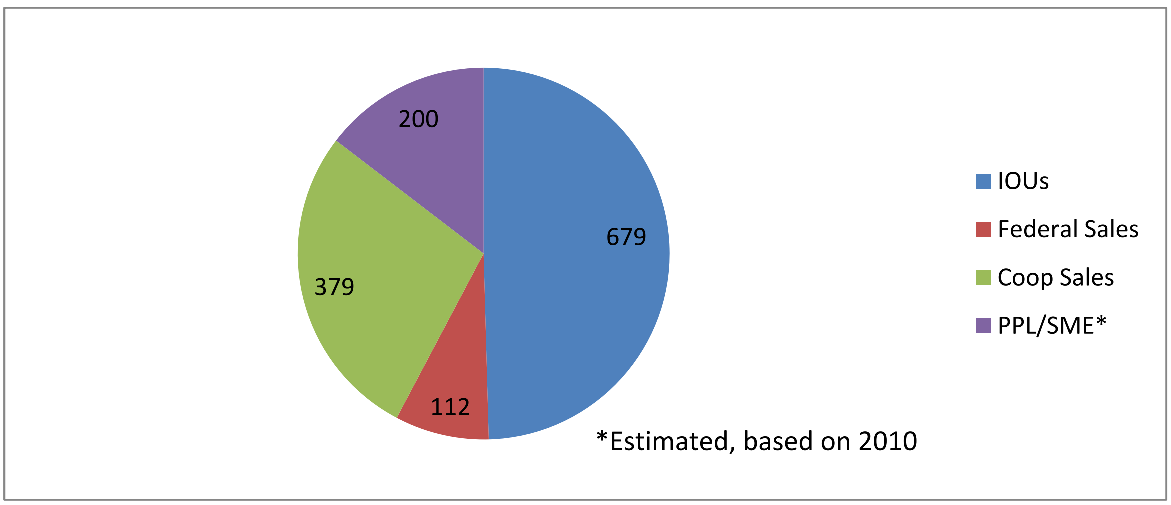
In general, these methods collectively suggest that PPL has monopoly power and as a result earned significant profits. Due to complexities in understanding exact revenues and specific cost information, exact welfare loss calculations are not possible. However, the compensating variation analysis, which relies on observed outcomes, suggests that a nominal value in excess of $722 million for the period from 2004 to 2009 is appropriate.

4.1 Aggregate Price and Demand

Four categories of retail sellers serve the Montana wholesale electrical market. Their proportions have remained roughly unchanged since 2004 (Figure 4.1.1): (1) Investor Owned Utilities, (2) Federal Power Providers, (3) Wholesale Power Providers and (4) Rural Electric Cooperatives. Four Investor Owned Utilities account for just over 50% of electrical sales in Montana: NorthWestern Energy

(92.3%), Montana Dakota Utilities (7.5%), Black Hills (.2%), and Avista (<0.001%). Federal Power Providers consist of the Bonneville Power Administration, the Western Area Power Administration and the state's one tribal utility: Mission Valley Power. Montana has 24 Rural Electrical Cooperatives which provide about one quarter of total electricity. There are currently two primary wholesale electricity providers in the state, not including NorthWestern Energy: (1) PPL Montana and (2) Electric City Power of Great Falls and its upstream supplier Southern Montana Electric, which sell wholesale power to industrial consumers in the state of Montana. These entities do not report to the Energy Information Administration.[82]

Figure 4.1.1 Montana Demand by Supplier Class, aMW (2004)

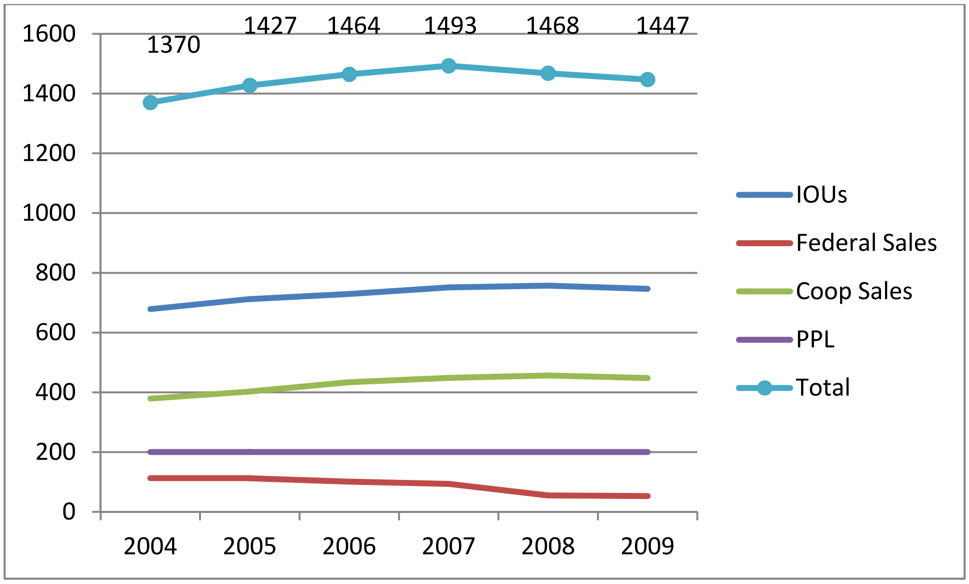


Since 2004, gross demand for electricity has been generally stable (Figure 4.1.2) with the Cooperatives and Investor Owned Utilities experiencing growth through 2008 and then a decline in

[82] United States Energy Information Institute Table 10a, see, http://www.eia.gov/cneaf/electricity/esr/backissues.html.

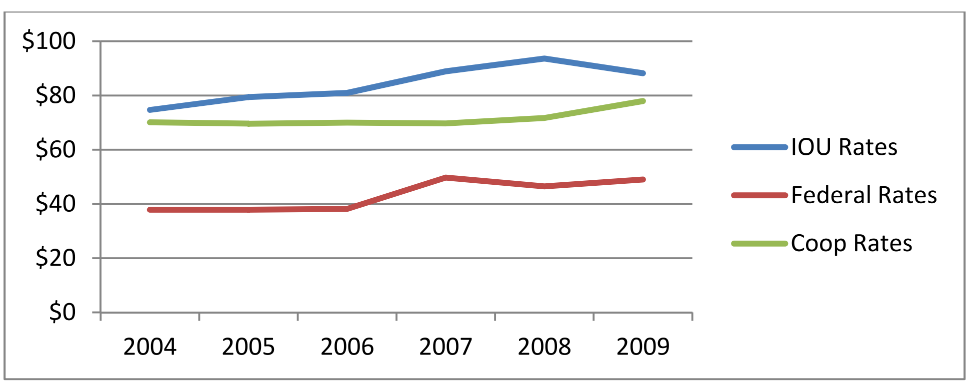
demand. Federal sales have decreased, largely due to the shuttering of the Columbia Falls Aluminum Smelter, which relied on power from the Bonneville Power Administration.[83]

Figure 4.1.2 Montana Historical Demand by Supplier Class, aMW



The Energy Information Administration tracks retail prices for these same entities for the same period, except for PPL and Southern Montana (Figure 4.1.3).

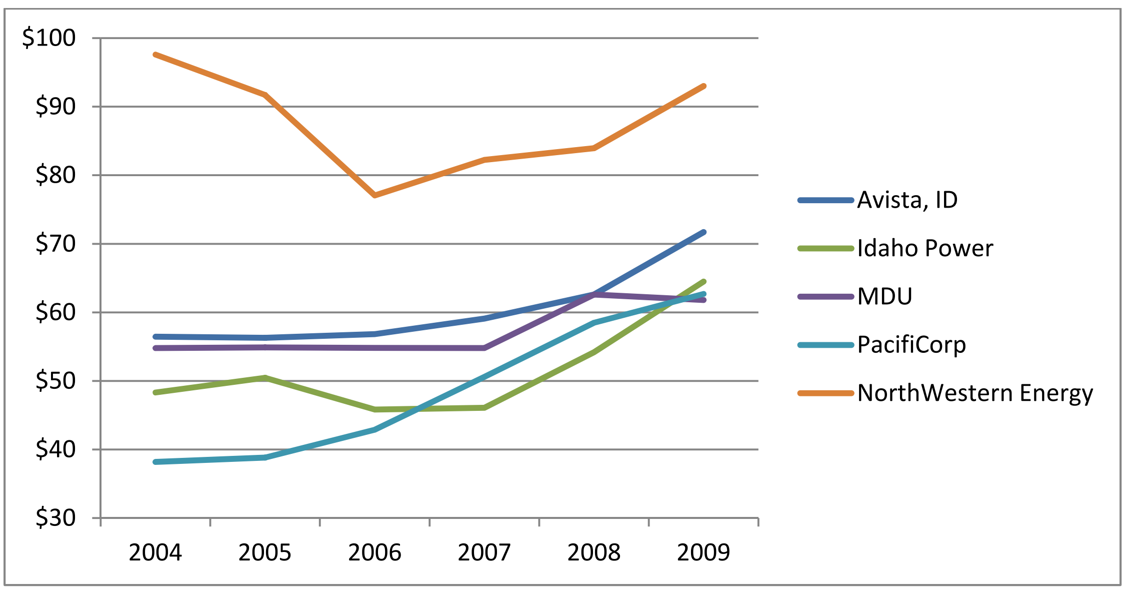
Figure 4.1.3 Montana Historical Retail Price by Supplier Class, $/MWh



[83] The plant had a load of about 140 MW. See the following for more information on plant shuttering and timing. Dan Testa, "Columbia Falls Aluminum Company to Shut Down", 12/23/2008, Flathead Beacon. See, http://www.flatheadbeacon.com/articles/article/breaking_cfac_notifies_workers_it_will_shut_down/7372/

Legacy contracts for electricity from federal hydroelectric dams and the difference in debt costs partly account for the large difference in the rates of Investor Owned Utilities and those receiving power from Federal Power Providers and Rural Electric Cooperatives.[84] Federal securities financed the federal hydroelectric dams, and they continue to deliver some of cheapest priced power in the United States. However, examining only the Investor Owned Utilities rates by utility shows that additional factors are influencing electrical prices (Figure 4.1.4) and that NorthWestern Energy's rates have far exceeded their neighboring utilities.[85] All of these utilities are multi-jurisdictional and receive slightly different rates in each state based on what their respective utility commission authorizes (PacifiCorp, for instance, operates in six western states).

Figure 4.1.4 Historical Retail Price, Investor Owned Utilities, $/MWh



The Energy Information Administration does not maintain statistics for individual utilities prior to 2004, but does have state-level cost and production data available. Historically, Idaho Power and the

[84] Investor Owned Utilities have received some benefits from these facilities, including power exchanges and credits. Today, NorthWestern Energy receives a credit that it distributes to customers that is equal to about $.5 per MWh. Rural Electrical Cooperatives typically have weighted debt costs that are almost half of what is available to Investor Owned Utilities.

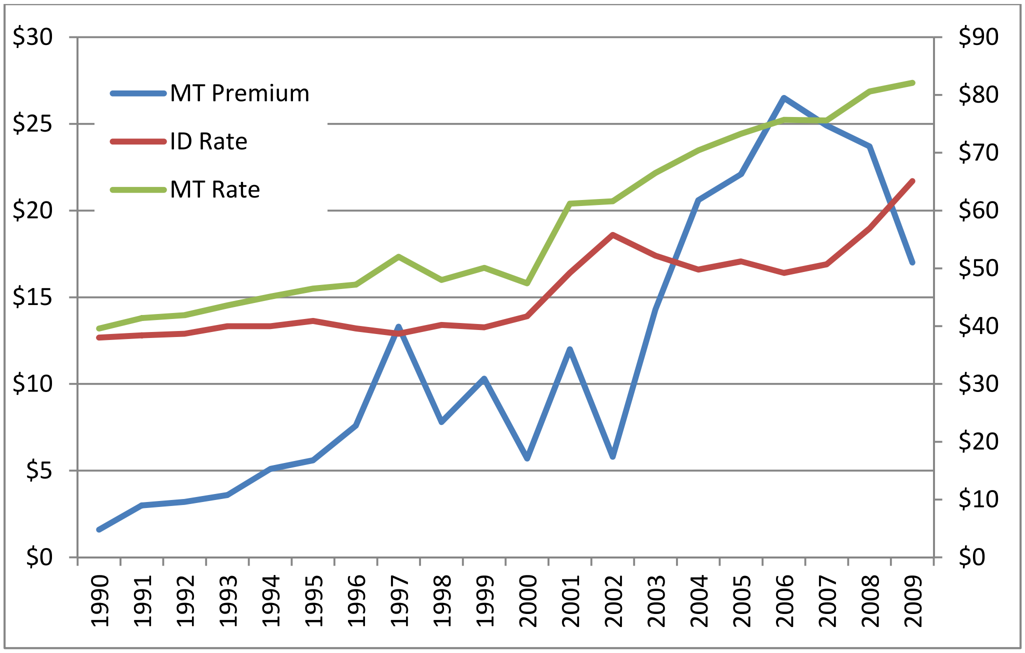
[85] Rates for Idaho Power, Avista, and PacifiCorp are reported for their Idaho loads and Montana Dakota Utilities are reported for their Montana loads.

MPC were the dominant electrical utilities in their respective regions. In Idaho, Idaho Power Company had 57.8% of total sales in 2004, in a market where the three Investor Owned Utilities accounted for 87.6% of sales (Avista had 14.9%, and PacifiCorp had 15.0%). The total Idaho market as reported by the Energy Information Administration was 2,485 aMW, with Idaho Power Company providing 1,435 aMW. Of the two states in the Western Interchange that border Montana, Idaho was selected over Wyoming for discrete comparison due to its similar demand structure. Wyoming has experienced extensive industrial load growth in the last decade due to the expansion of oil and gas exploration and refining.

Figure 4.1.5 shows a comparison of the end retail rates for the period available from the Energy Information Administration.[86] From 1990 through 2009 rates were similar between the states, with Montana rates carrying no more than a $15 per MWh premium to Idaho. In 2004, two years after the cost caps on deregulation expired, Montana rates jumped to a $20.6 per MWh premium over Idaho rates. By 2006, the premium was $26.5 per MWh, before relaxing to $17 per MWh in 2009, the last year of data from the Energy Information Administration. The rates in Figure 4.1.5 soften the actual impact of deregulation, as they are at the state level and do not compare retail rates for MPC or NorthWestern Energy customers where the effects of deregulation were concentrated.

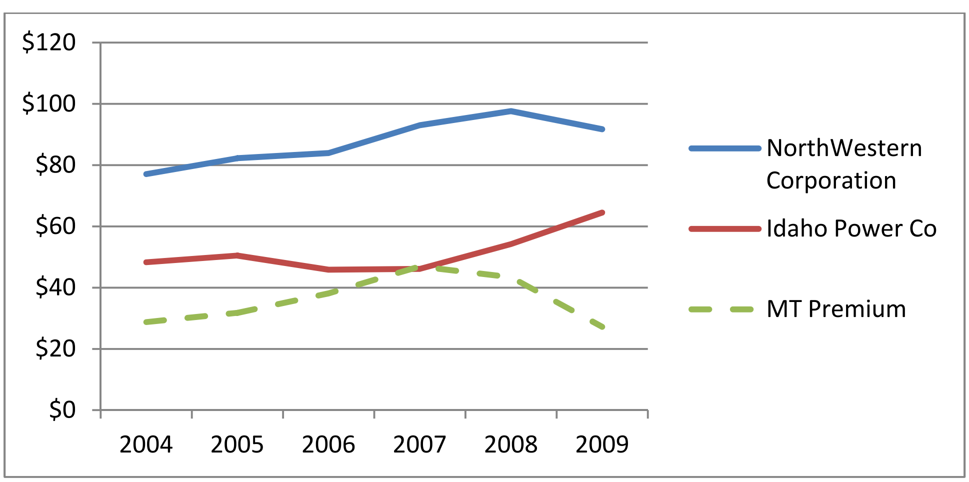
[86] Energy Information Administration Table 8.

Figure 4.1.5 MT to ID Historical Retail Price Electrical Comparison, $/MWh



Comparing the more discrete data available from the Energy Information Administration for NorthWestern Energy and Idaho Power reveals an even more significant departure (Figure 4.1.6). Here the NorthWestern premium starts at $28 per MWh, a 33% increase from the aggregate state statistics and increases to $46 per MWh in 2007, when NorthWestern Energy customers were paying more than double Idaho Power customers. The premium narrowed through 2009 to $27 per MWh.

Figure 4.1.6 NorthWestern Energy Historical Premium to Idaho Power, $/MWh



Chapter 3 discussed the role of marginal cost information in economic models. In the absence of discrete marginal cost information, a compensating variation analysis can provide similar insight into market power dynamics in the Montana market. This analysis considers the price premium NorthWestern Energy customers pay relative to Idaho Power's customers. For the analysis to hold, the underlying factor costs of both utilities must be constant, or changes must at least be small, to assess the impacts of a specific policy change, in this case the expiration of the price caps implemented under deregulation.

No evidence shows a change in factor costs during this period, or previous periods, that would explain the increase in the Montana to Idaho premium.[87] Both electrical utilities had similar supply structures, with the majority of electricity provided by hydroelectric facilities located inside each state, augmented by large mine-mouth coal plants - Jim Bridge (located in Wyoming) and Colstrip. Idaho Power probably realized some economies of scale with a larger, more concentrated population, but these would have been legacy savings.[88] There were no significant tax changes in either Idaho or Montana, and as factor production shares are both dependent on the same resource supply, changes in fuel costs would similarly affect both utilities.

To calculate the welfare loss attributable to deregulation, a "normal" premium is required. Two values are considered, a \$15 per MWh premium, which is the rounded mean of the long-term average data from the Energy Information Administration for Montana and Idaho (Figure 4.1.5), and a conservative premium of \$20 per MWh. Under the conservative premium, the welfare loss is a nominal aggregate amount of \$551 million or \$92 million annually. At \$15 per MWh, the welfare loss is \$722

[87] Montana did change its taxation structure for electrical utilities in 1999. The Legislature reduced the tax rate on electrical generation property from twelve percent to six percent, and instituted a wholesale energy transaction currently 0.015 cents per kilowatt-hour. Total tax collection from both taxes amounted to \$7.44 million in 2005.

[88] The transmission rate differential implies this. Idaho Power's FERC authorized transmission rate is \$18,000 and NorthWestern Energy's is \$37,920 per MW. This differential alone, assuming 75% transmission utilization explains \$3 per MWh of the difference. This does not include any difference in retail transmission tariffs.

million or $120 million annually. The $20 per MWh premium amounts to an average annual cost per NorthWestern Energy customer of $285.70.

Even at the conservative $20 per MWh premium these are large numbers. PPL acquired MPC's generation assets for $838 million in 1998 dollars or $1,115.3 million in 2010 dollars. At the $20 per MWh premium, the welfare loss alone would have covered almost 50% of its acquisition cost for just this six-year period. If this premium had been invested in new wind generation capacity, the value would have equaled the capital cost of approximately 250 MW of new wind.[89] At the $15 per MWh premium the six-year welfare loss represents 86% of the nominal purchase price for MPC's generation.

4.2 Market Organization and Transmission

Electrical markets have three levels of vertical organization. A transmission provider manages the high-voltage transmission system, providing control and coordination related to scheduling and delivering electricity within its footprint. Chapter 2 discussed the structure of this system in more detail: any generator or retail service provider has non-discriminatory access to use the transmission system. Wholesale generators and retail suppliers form the other two levels of the system. The retail supplier typically owns the retail distribution system, the low-voltage lines that serve residences and business. Depending on the region, vertical integration can occur across any combination of these three levels.

In Montana, NorthWestern Energy largely owns the western portion of the state's high voltage transmission system. The Bonneville Power Administration also owns transmission that delivers electricity from its generation resources in Montana as well as the Colstrip 500 kV system west of Townsend. NorthWestern Energy also owns most retail distribution in urban areas of Montana (except in Kalispell) and electrical cooperatives own the system in rural areas.

[89] Assuming wind capital costs of $2,200 per kW.

NorthWestern Energy and the Bonneville Power Administration charge an established rate that is approved by the FERC for access and use of the transmission system.[90] Any entity wishing to move electricity across NorthWestern Energy's system must pay this rate. As such, it functions as a hotelling cost for generators located on other transmission systems to access demand outside of NorthWestern Energy's systems. The result is price parity between generations, regardless of location, once transmission costs are internalized, if there are no capacity constraints. Similarly, generators within NorthWestern Energy's system face the hotelling cost of the transmission rate of the transmission system they deliver to or cross to reach a retail load buyer.

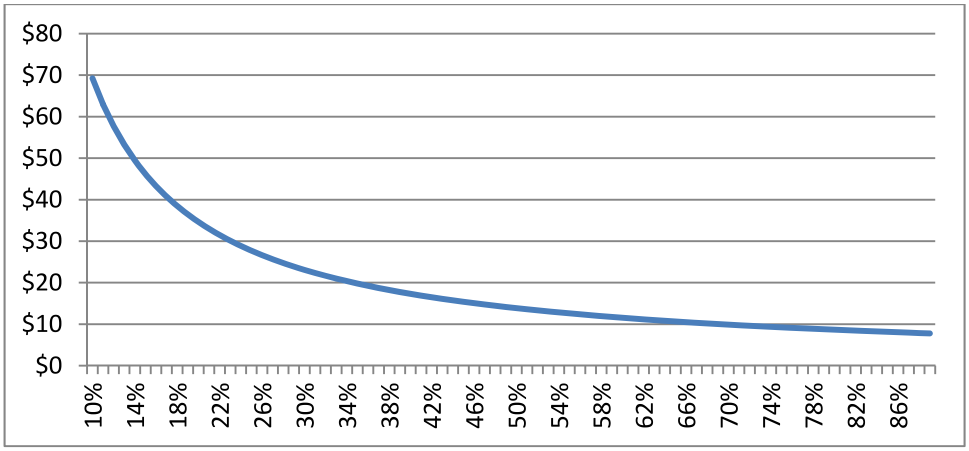
Generators or utilities reserve transmission capacity under a use it or lose it system from transmission providers.[91] This system creates increasing marginal costs for production as transmission utilization decreases. As such, the average cost of the capacity for other units increases as utilization falls. Figure 4.2.1 shows how transmission costs change at different capacity factors for a $60,672 transmission tariff, which is equivalent to cost of moving power across BPA's and NorthWestern Energy's transmission system. For instance, shifting from 60% to 50% utilization would imply an increased average marginal cost for transmission of $2.31 per MWh.

Montana generators with transmission rights to deliver electricity outside of Montana may have a disincentive to sell into Montana. By selling energy into Montana, they decrease the utilization of their transmission rights and increase the average marginal cost for the remaining energy. At high-utilization rates the effect is small, but for generators with lower utilization rates, the costs can be significant. Owners of the Colstrip Generation Units that serve load outside of state would face these economics would they decide to sell into the Montana electrical market.

[90] Each transmission provider's Open Access Transmission Tariff establishes this rate and includes a charge for line losses, transmission, imbalance, frequency response and spinning and supplemental reserves.

[91] There are provisions for resale of this capacity under the Open Access Transmission System.

Figure 4.2.1 Cost of Transmission as a Function of Utilization, $/MWh



Transmission rates vary from provider to provider. NorthWestern Energy's 2011 FERC-approved rates are $37,920 per MW year with 4% losses.[92] Assuming full utilization of a yearly transmission right and $50 per MWh value for line losses, the transmission or wheeling charge is $6.33 per MWh.[93] BPA's point to point rate is $15,576 per MW/year with 1.9% losses. BPA also charges $7,176 per MW for a portion of the 500 kV system in Montana, the "Montana Intertie".[94] Using the same assumption as with NorthWestern Energy, the Bonneville Power Administration's wheeling charge is $2.72 without the Montana Intertie, and $3.54 with the intertie.[95] The implication of these rates is that the transmission tariff for the host Balancing Authority Area will provide a barrier to entry for generation in adjacent balancing authority area, such that PPL enjoys a barrier of entry of $6.33 and will incur an incremental cost of $3.54 to reach the Bonneville Power Administration.

[92] Loss rates are charged on energy transmission, so that for a 100 MWh of transmitted energy a customer would have to provide 4 additional MWh to cover losses, or alternatively purchase 4 MWh from the Transmission (for a system that had a 4% loss charge). For current rates, see NorthWestern Energy's approved Open Access Transmission Tariff, Schedule 7, see, http://www.oatioasis.com/NWMT/NWMTdocs/NWMT_FERC_Transmission_Tariff.pdf

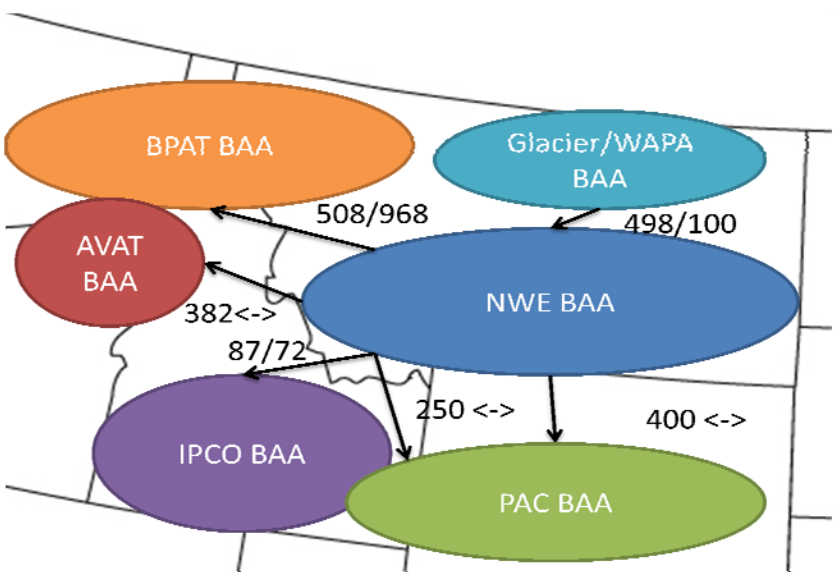
[93] MWh rates can be calculated through the following formula: (Annual Transmission rate/8760) + [(8760 *loss factor * energy value)/8760].

[94] For the Bonneville Power Administration's rates, see http://transmission.bpa.gov/Business/rates/default.cfm

[95] BPA also charges a specific rate for the Townsend to Garrison section of the Montana Intertie. For current rates see, http://transmission.bpa.gov/Business/Rates/documents/2012_rate_schedule_summary_090811.pdf.

Figure 4.2.2 shows the topology for the transmission system. NorthWestern Energy's transmission system interfaces with transmission systems owned by the Bonneville Power Administration and Avista on the west, Idaho Power and PacifiCorp to the South, and the Western Area Power Administration and NaturEner (the Glacier Wind Farm) to the north. The interface may include just one line or several lines and substations where electricity can move between the systems. The Western Electricity Coordination Council works with the utilities to assign path rating to these transfers, which are denoted in MW. Utilities can than coordinate to schedule electricity across the interchanges. The capacity available for the export and import paths with each adjacent balancing authority to NorthWestern Energy is provided in Figure 4.2.2 (NTTG, 2011). These paths do not include export capacity from Colstrip to the Pacific NorthWest that is available on the Colstrip 500 kV transmission system, or the small amount of import capacity from the eastern interconnect. MID-C is located within the BPAT bubble. A Montana based generator wishing to move power to Idaho, would have to pay the Idaho Power and NorthWetern Energy tariff price.

Figure 4.2.2 Transmission Topology (2010)[96]

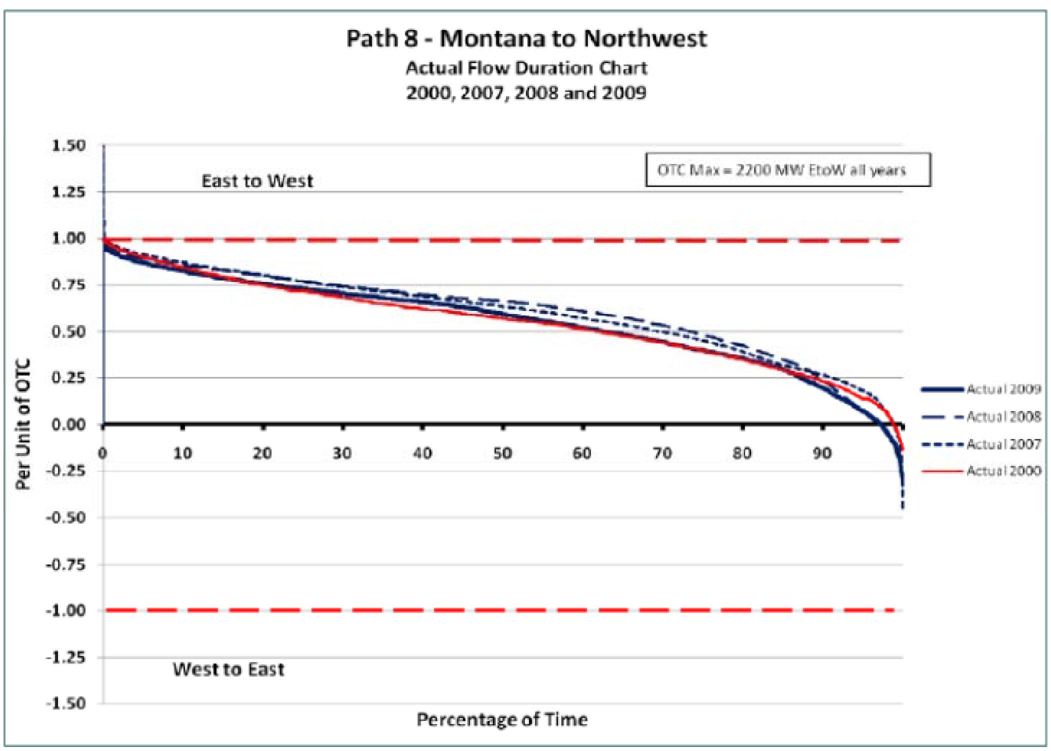


[96] Labels denote "Import/Export" capacity. Each transmission providers system is abbreviated: Idaho Power Company (IPCO), Avista (AVAT), Bonneville Power Administration (BPAT), NorthWestern Energy (NWMT), PacifiCorp (PAC), and the Western Area Power Administration (WAPA).

Excluding the 500 kV Colstrip System NorthWestern Energy's Balancing Authority Area has 2,125 MW of physical import capacity and 2,244 MW of physical export capacity

Contract rights determine reservable transmission availability. Currently, there are 177 MW of winter long-term capacity between Avista and NorthWestern Energy, 283 MW of capacity with Bonneville Power Administration, zero MW with PacifiCorp and only seven MW with Idaho (NTTG, 2011). Actual use of these paths shows that their utilization is higher than 75% of actual capacity only about 15% of the time. The utilization curve is also positive for 97%-98% of the time, indicating that the path is almost exclusively used for export and that actual flows almost never move from the Pacific NorthWest into Montana. Figure 4.2.3, shows the utilization curve for four different historical years for Path 8, the interface between the balancing authority areas of NorthWestern Energy and the Bonneville Power Administration

Figure 4.2.4 Montana to Northwest Path Duration Chart (WECC, 2011)



4.3 Wholesale Data Analysis

In 2001, the FERC issued Order 2001, which required entities making wholesale power transactions to file Electric Quarterly Reports with the FERC ("FERC Dataset"). The FERC Dataset offers insight into Montana's electrical market and PPL's revenue structure, which are reviewed in this section.

The FERC Dataset only includes wholesale electrical transactions by quarter and does not have information about the pricing of downstream retail sales. It allows analysis of average pricing conditions over a number of contract attributes, such as period, duration, and term. The FERC Dataset differentiates between short-term and long-term transactions, with long-term transactions a year or longer. In analyzing the data, quantities were not able to be reconciled in two situations. First, PPL's total sale quantity increases over the data period, though their physical capacity was constant. Second, NorthWestern Energy in several years purchased significantly (two or three times) more electricity than it needed to meet even its most liberal native load needs, even accounting for its reported resales of energy. Interestingly, the FERC data set contains no data for PPL's transactions in Montana for the last two quarters of 2004, a period that corresponds with the FERC's review of its market-based rate authority.[97]

The absence of reliable quantity information in the FERC Dataset raises questions about its effectiveness in providing regulators a realistic view of market behavior. For instance, the database's lack of demand information inhibits a direct calculation of a residual supply curve. Resales and purchases also mask utilities' true production, making it impossible for the FERC to detect capacity withholding which may indicate the exercise of market power. These issues, combined with certain missing data periods, and a lack of information about transaction timing, limit the usefulness of the FERC

[97] An inquiry was made to FERC's staff to determine why the data was missing, with no response.

Dataset. The FERC Dataset does reveal some important price and sales trends about the Montana electrical market.

The data reveals that Montana's primary electricity buyer, NorthWestern Energy, can access the MID-C Market for short-term transactions to meet its demand obligations. The MID-C market, on average, has traded at a quarterly premium of $7.16 per MWh over the price that NorthWestern pays for electricity in Montana.[98] NorthWestern Energy has purchased an average of 137 aMW annually from this market and must pay transmission fees to transport this electricity back to Montana equivalent to a premium of about $3.54, the cost of the Bonneville Power Administration transmission charge at 100% utilization. These factors create a price differential between the MID-C price and the price in Montana of what is described as a five dollar differential, with Montana being less.[99]

NorthWestern Energy has depended on PPL and Investor Owned Utilities to meets its demand obligations, and has erratically used the Fringe.[100] Figure 4.3.1 shows NorthWestern Energy's total quantity purchases from four categories of sellers. PPL's supply to NorthWestern Energy has averaged nearly 400 aMW through the third quarter of 2008, with a peak in December 2007, and has since fallen to less than 300 aMW. Supply by the Fringe has been erratic, and Investor Owned Utilities have supplied an average of 72.6 aMW.[101] NorthWestern Energy has reported purchases from its own supply division related to Judith Gap, their share of Colstrip Unit 4[102], and the Thompson River Qualifying Facility.

[98] This is calculated based on weighted short-term transactions in the NorthWestern Energy Balancing Area, as compared to those at MID-C.

[99] NorthWestern Energy supply staff indicated in conversations with the author that their expectation for purchased energy prices in Montana is MID-C minus $5, and the same differential offered by PPL.

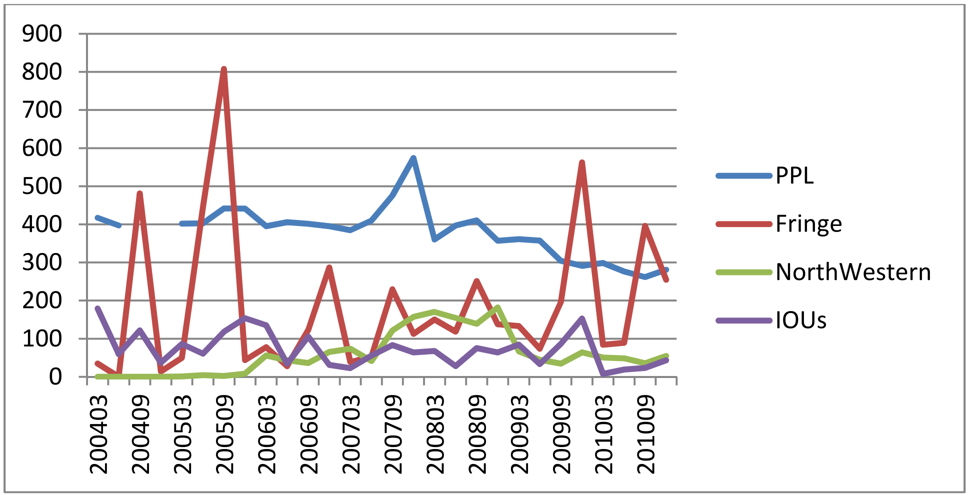
[100] In this context, the "Fringe" is all suppliers other than the Investor Owned Utilities, PPL and NorthWestern Energy.

[101] Investor owned utilities are defined as the investor utilities that own capacity in NorthWestern Energy's Balancing Authority, but export the energy to meet their retail load obligations. They include: Avista, Portland General Electric Company, PacifiCorp, Idaho Power Company and Puget Sound Energy.

[102] NorthWestern Energy ceased reporting these sales once the facility was placed in the rate-base.

Overall, NorthWestern Energy's reliance on the wholesale electrical market has decreased since the passage of House Bill 25 which reauthorized vertical integration in 2007.

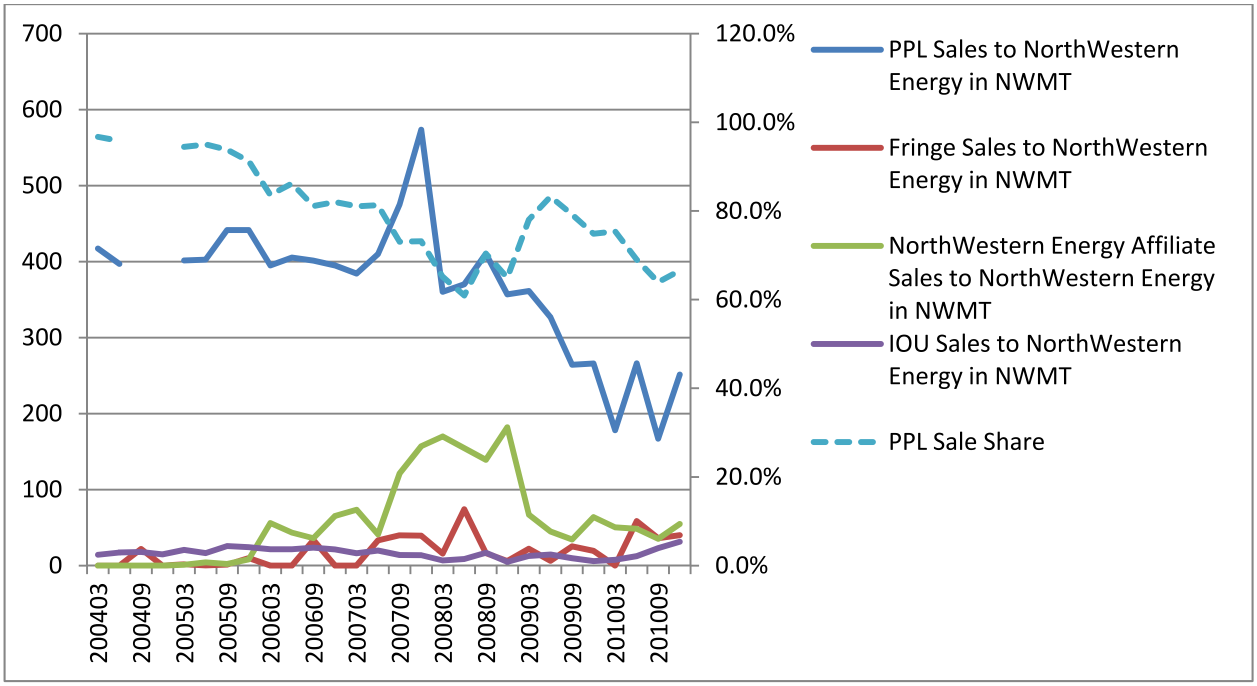
Figure 4.3.1 Quarterly Purchases by NorthWestern Energy, aMW



An examination of purchases made by NorthWestern Energy within their Balancing Authority Area demonstrates that PPL provides a significant portion of the electricity they acquire from the wholesale market. However, PPL's share is decreasing, with only 60% of NorthWestern Energy's wholesale electricity acquired from PPL in the second quarter of 2008 (Figure 4.3.2). PPL had provided at least 87% of NorthWestern Energy's electricity through the third quarter of 2009. The Seven Year Contract provides an equivalent of 275 aMW – a fixed wholesale transactions between the parties.[103] This indicates that as of the third quarter of 2009 that NorthWestern Energy's only wholesale purchases from PPL relate to quantities under this contract. Prior to that, NorthWestern Energy had purchased about 125 aMW from PPL, except for the fourth quarter of 2007. Comparatively, purchases from either the Fringe or Investor Owned Utilities are minimal, and have never accounted for more than 75 aMW individually.

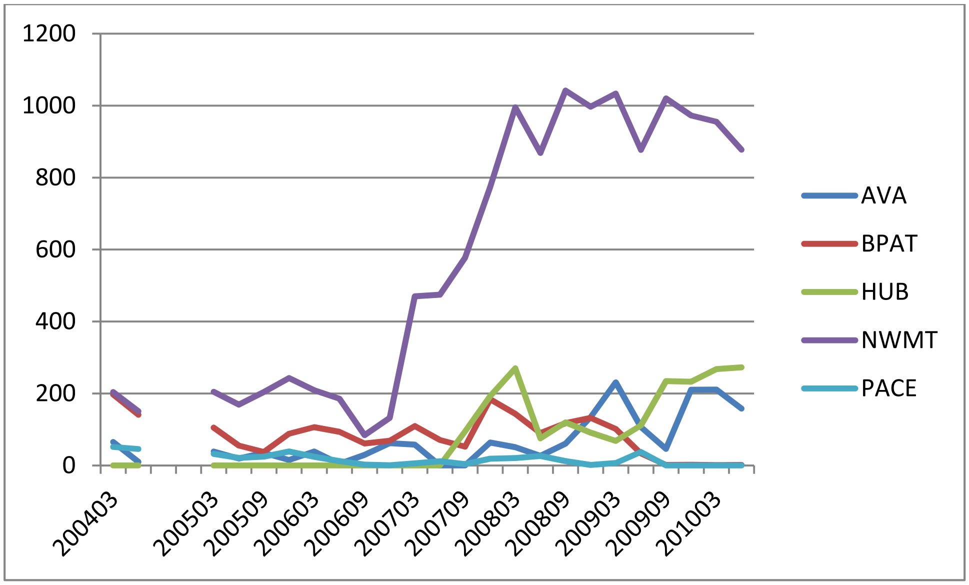
[103] Assumes that PPL provides 5,835 hours of energy at peak quantities each year.

Figure 4.3.2 Quarterly Purchases by NorthWestern Energy within their BAA, aMW



As PPL's sales to NorthWestern Energy have declined, its sales to other entities have increased. Beginning in the second quarter of 2007, PPL started to sell an excess of 400 aMW within the NorthWestern Energy Balancing Authority Area. Figure 4.3.4 shows PPL's sales, excluding those to NorthWestern Energy, for the five largest Balancing Authority Areas. Interestingly, PPL did not begin making sales to MID-C ("HUB") until the third quarter of 2009 and has generally expanded its sales to other Balancing Authority Areas. Sales to entities other than NorthWestern Energy began expanding significantly in the first quarter of 2007.

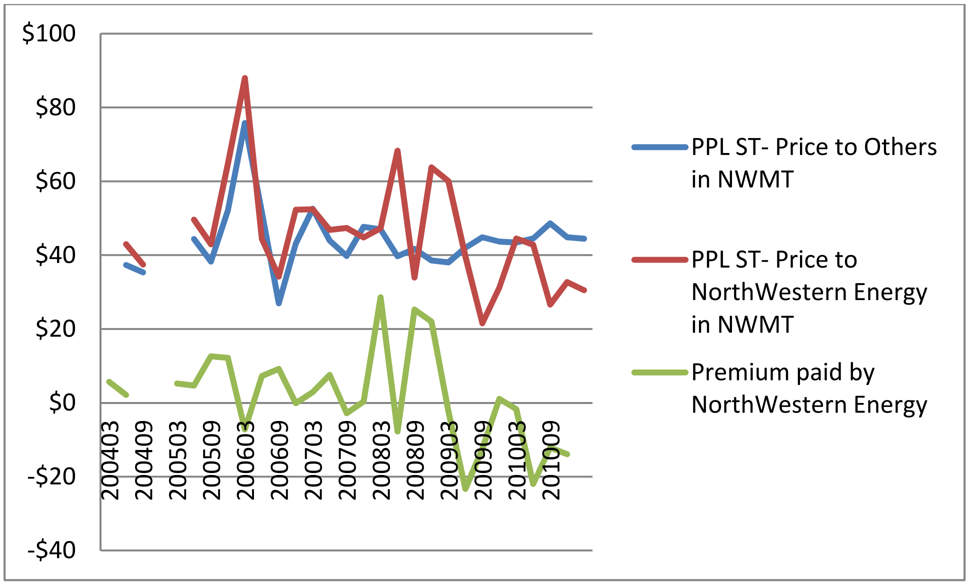
Figure 4.3.3 Location of PPL's Sales other than NorthWestern Energy, aMW



There is little distinction between the price that PPL has received for sales inside and outside of the NorthWestern Energy Balancing Authority. PPL on average has sold electricity into adjacent Balancing Authority Areas at about the same price that it received from NorthWestern Energy. This would seem to indicate that PPL internalizes the cost of transmission in these sales. The price convergence indicates that the Montana wholesale market is now reflecting the broader regional market, as a consequence of PPL's market power within Montana.

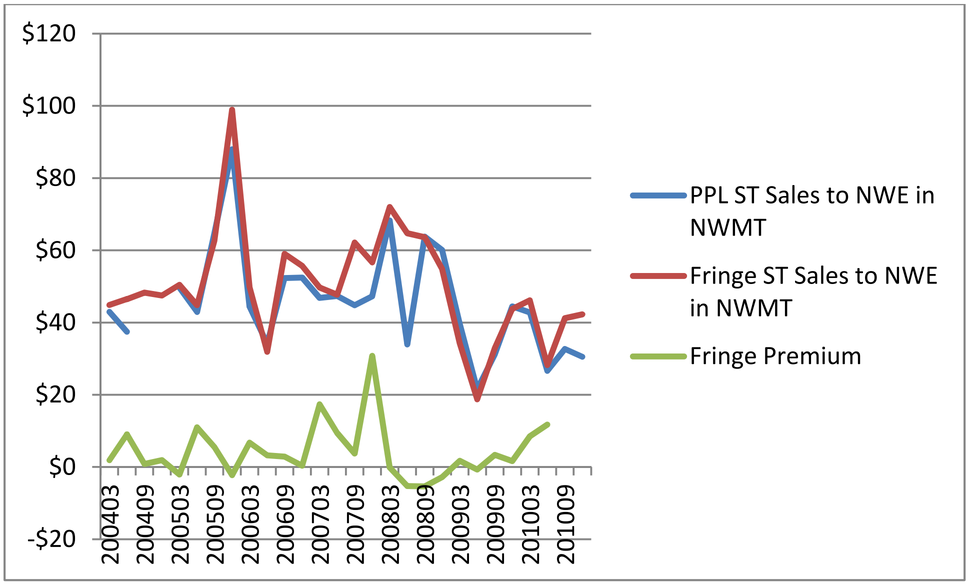
However, the Montana market does not appear to have homogenous pricing for buyers. On average PPL has received a premium of $5.9 per MWh from NorthWestern Energy as compared to its sales to other entities in the Balancing Authority Area for short-term sales, which would not include the Seven Year Contract. This premium stopped in the first quarter of 2009, after which NorthWestern Energy began to receive a discount. Figure 4.3.4 shows this premium over the period of record.

Figure 4.3.4 Historical NorthWestern Energy Price Premium from PPL, $/MWh



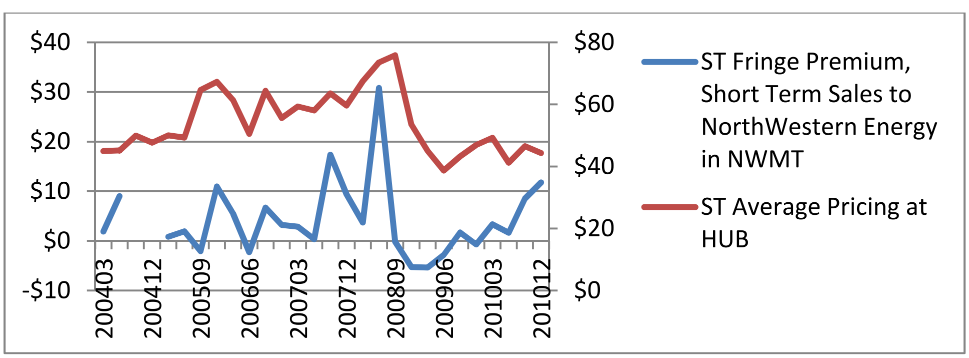
NorthWestern Energy also pays a premium when it purchases power from the Fringe, those sellers that are not Investor Owned Utilities. Figure 4.3.5 shows the short-term Fringe and PPL price that NorthWestern Energy has paid. NorthWestern Energy has paid an average premium to the Fringe of $4.33 per MWh compared to PPL. Given the erratic Fringe quantities, the premium may simply reflect differences in spot prices, with NorthWestern Energy only using Fringe purchases in high demand periods. These periods would tend to have higher electricity prices. However, given the sustained nature of the premium, including during the second quarter when large quantities are hydroelectricity available in the Pacific NorthWest, the premium may demonstrate that PPL is price setting below the Fringe entry price to deter entry.

Figure 4.3.5 Historical PPL and Fringe Price to NorthWestern Energy, $/MWh



The Fringe premium correlates with MID-C prices. The correlation over the FERC Dataset for the Fringe premium and the average short-term price at MID-C is .41. A positive correlation indicates a positive relationship and a value of 1 would indicate a perfect correlation. A t-test indicates if this value is significant. At a 5% alpha value, the significant t-value is 2.074.[104] The correlation has a t-value of 2.1, allowing the rejection of the null hypothesis that the correlation is random. This implies that the premium that NorthWestern Energy pays the Fringe increases as the MID-C market price increases (Figure 4.3.6).

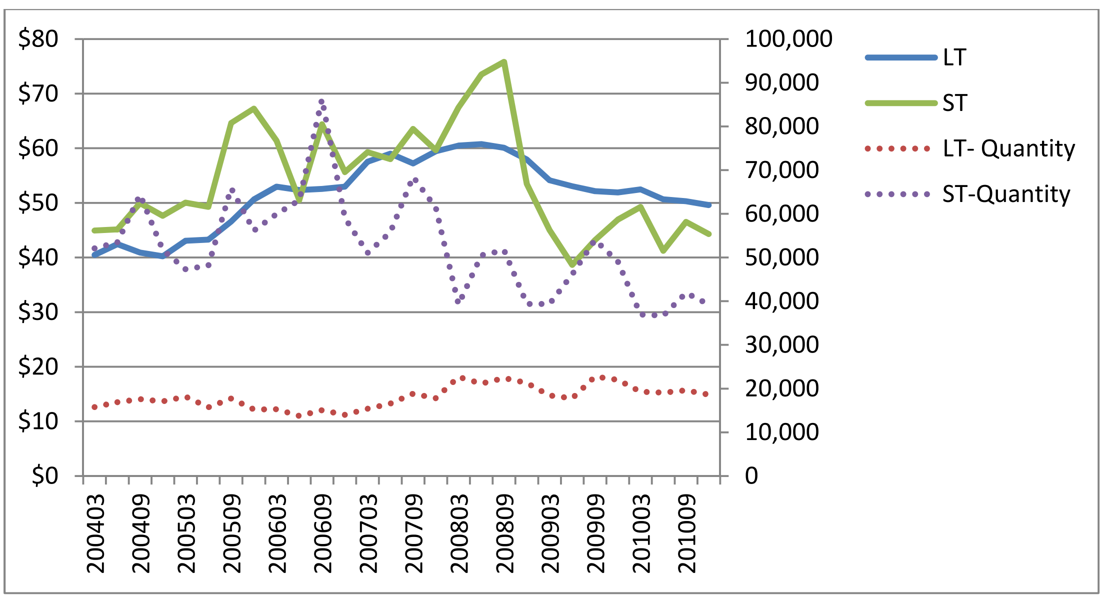
Figure 4.3.6 Fringe Premium Compared to MID-C, $/MWh



[104] See, http://en.wikipedia.org/wiki/Student's_t-distribution

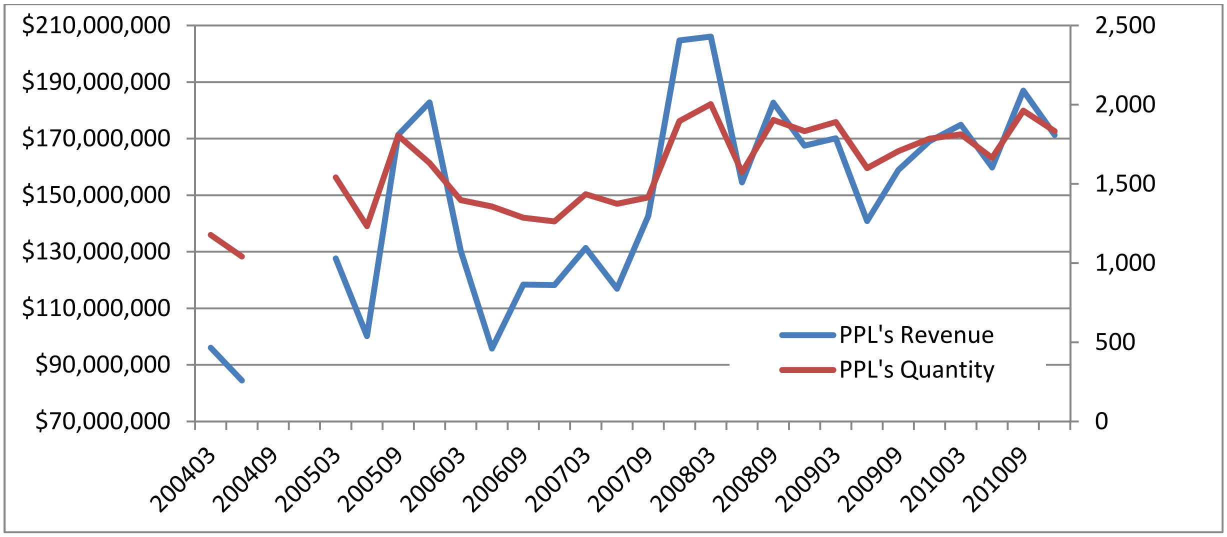
The MID-C market has clear seasonality that inversely follows the region's hydroelectric production. Prices peak typically in the fourth quarter, and volumes peak in the third quarter. The second quarter, when hydroelectric production is at the highest, corresponds to the lowest pricing. In fact, recent years have actually seen negative prices at the market, which are a function of the penalties that hydroelectric operators must pay for spilling excess water (not running it through turbines to generate electricity) associated with violating dissolved gas standards which increases fish mortality. The market has also experienced a fundamental downward average price adjustment of about $20 per MWh over the fourth quarter of 2008 and the first quarter of 2009, which does not appear to be linked to total quantity traded. Figure 4.3.7 shows aMW volumes at MID-C for long and short-term transactions and prices.

Figure 4.3.7 MID-C Prices and Quantities, Short-Term (ST) and Long-Term (LT) transactions



As the FERC Dataset captures all prices and quantities sold on the wholesale market, it allows for a computation of total revenue. Figure 4.3.8 shows PPL's revenues from its Montana assets and the quantity sold. Revenue does appear to correspond to quantity sold, which would be expected. A growing inverse relationship may indicate capacity withholding, and thus market power. However, the resolution of the FERC Dataset is probably not robust enough to test for quantity withholding, especially without detailed information about marginal cost structures.

Figure 4.3.8 PPL's Historical Quantity and Revenue



Revenue information can still provide insight about market power, by calculating price mark-ups (see Chapter 3). Pairing revenues with even simple cost assumptions also allows the extrapolation of estimated profits.

An assessment of PPL's profits requires an understanding of its cost structure. PPL's cost structure for its Montana assets has three general components: capital and debt service costs related to the purchase price for the assets, variable fuel costs, and administrative or operating expenses (licensing, lobbying, labor, and taxes). PPL owns only hydroelectric and coal facilities in Montana. As hydroelectric plants do not require any fuel, the costs of operating these units should be less than PPL's coal units. One proxy for the cost of operating PPL's coal facilities (all of which but one, is part of Colstrip), is the rate that NorthWestern Energy received for Colstrip Unit 4, before rate-basing the asset. This rate was approximately $35 per MWh. With some administrative expenses, and accounting for the capital service costs[105] of the hydroelectric facilities a ceiling for the long-run average cost structure for PPL is around $40 per MWh. This cost it is $18.5 above the deregulation price cap, and $8 above the initial rate they charged after the caps expired. Given that hydroelectric facilities should decrease the weighted average cost, a $30 per MWh average cost may be more realistic.

At an average cost of $40 per MWh, PPL would have realized an average quarterly profit of $10.7 million on the revenue that they earned from transactions recorded in the FERC Dataset, just considering those that were described as an "ENERGY" product for which the type was dollars per MWh. At a lower marginal cost of $30 per MWh PPL would have realized an average quarterly profit of $51.9 million.

PPL almost certainly earned additional revenue, outside of these transactions. The above calculation is based on 947,000 of PPL's transactions, which represents only 62% of the total transactions in the FERC Dataset. These additional transactions include sales of MW Days and Months, capacity, and ancillary services.[106] Combining all transactions, PPL reported an annual average quarterly revenue of $229 million or $5.041 billion in total revenue for the 22 quarters that they reported from 2004-2010 to FERC. This reporting does not include revenue from retail sales to end-use industrial customers in Montana, which with an average volume of 200 aMW and a conservative price of $40 per MWh, below the value of the Seven Year Contract with NorthWestern Energy, represents an additional $490 million in revenue. As such, total estimated revenue for PPL, for the seven-year period of the FERC Dataset is approximately $5.5 billion, for assets which PPL purchased for $1.115 billion for in 2010 dollars.

[105]At a weighted capital cost of 8% (reflecting 50% debt at 6% and 50% equity at 12%) the 20-year interest cost of the asset purchase price of MPC's generation assets, assuming no depreciation or tax benefit returns, and a single annual payment, would be $9.03 per MWh with an average output of 1,071 aMW (PPL's adjusted seasonal capacity proposed to the FERC).

[106] Capacity and ancillary services are additional services that can be sold by electrical generators, which help to balance the system and maintain reliability.

To estimate costs for PPL at the generation level, an understanding of PPL's electricity production is needed. PPL has 1,329 MW of electric generation capacity. One source suggests that capacity factors for Colstrip Units 3 and 4 could be as high as 89%.[107] Assuming the same capacity factor for PPL's hydroelectric facilities renders total aMW generation of 1,183 aMW, which is slightly higher than the average value of 1,137 used by the FERC (Table 2.4.1). At the average cost ceiling of $40 per MWh, total costs for PPL would be $414,456,624 annually or $2,901,196,368 over seven years. With revenues of $5.5 billion, PPL could have easily made profits in excess of $2.4 billion for just the seven year period of record from the FERC Dataset.

This section has showed that NorthWestern Energy had paid an average premium of $6.9 per MWh for purchase from PPL within its Balancing Authority Area for short-term energy. It now appears that as a consequence of ongoing vertical integration, that this premium has been eliminated. PPL has probably made significant profits from 2004-2011, in excess of $2.4 billion. These factors offer evidence that PPL had market power within the Montana electrical market, which is tempered by the Seven Year Contract.

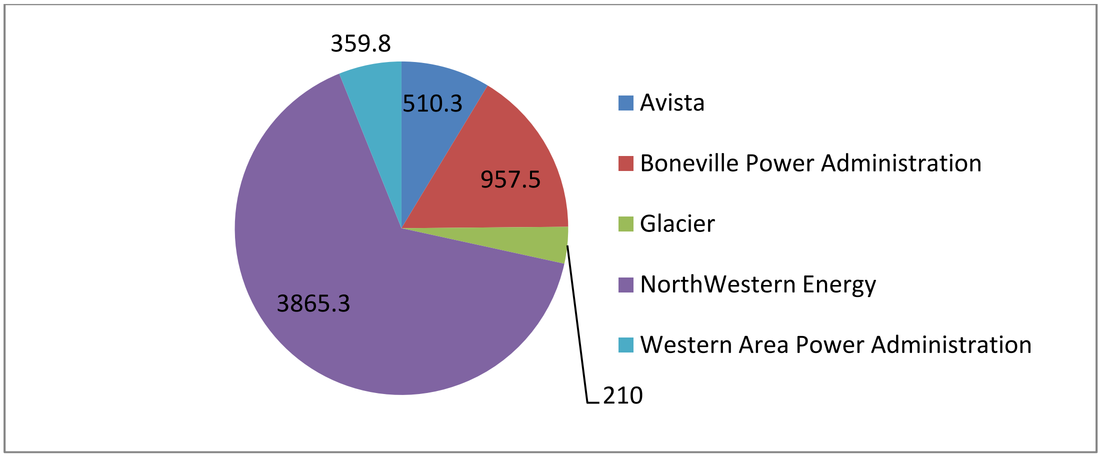
4.4 Montana Generation Classification

Electrical generation capacities are fairly stable as a result of long construction lead times and large capital investment. As described in Chapter 1, Montana generation capacity increased significantly after 2004. As of the second quarter of 2011, Montana had 5,902.9 MW of installed electrical generation capacity. This capacity is located within five Balancing Authority Areas, with 65% located in

[107] See, http://www.epa.gov/region8/air/pdf/Colstrip3_4NOx.pdf

NorthWestern Energy's Balancing Authority Area.   Figure 4.4.1 provides the capacity by Balancing Authority Area.[108]

Figure 4.4.1 Location of Montana Electrical Capacity by Balancing Authority Area (2010)



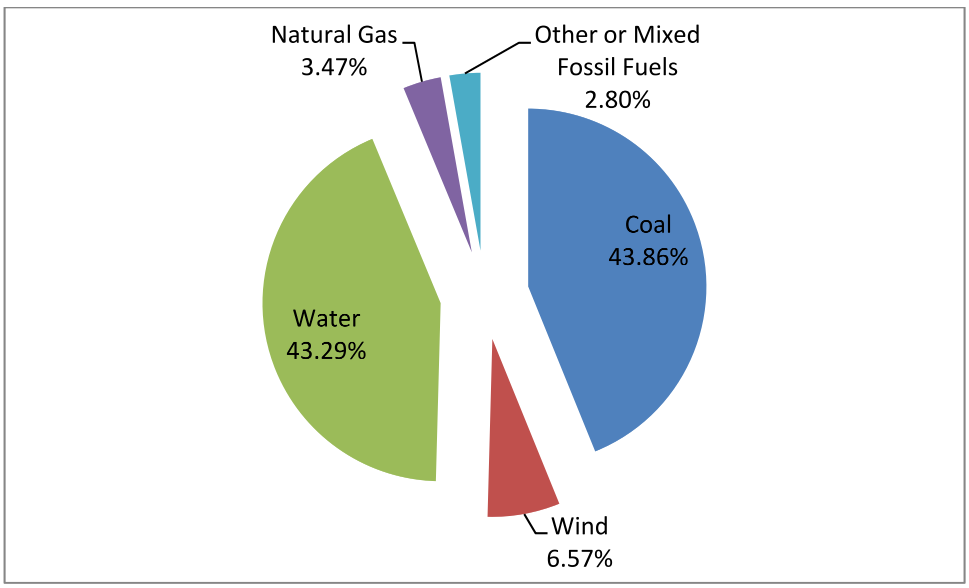
Five entities own the majority of this capacity. Either PPL or the Federal Power Providers own 47% of this capacity. Figure 4.4.1 provides a breakout of the capacity by ownership. Interestingly, NorthWestern Energy had 13.6 MW less of either owned or contractual capacity than Puget Sound Energy, which has no native load obligations in Montana, or adjacent states. NorthWestern Energy has also increased its capacity by almost 10 fold from 2004 to 2011. The capacity is broken down by fuel source in Figure 4.4.2, and Appendix II provides a complete listing of all facilities in Montana.

[108] This ignores any dynamic scheduling and places all of the facilities of the Western Area Power Administration and Montana-Dakota Utilities outside of NorthWestern Energy's Balancing Authority Area, except for Canyon Ferry.

Table 4.4.1 Control of Montana Electrical Capacity

	Montana State wide Ownership, 2011		NorthWestern Energy's Balancing Authority Area, 2004		NorthWestern Energy's Balancing Authority Area, 2011	
	(MW)	(%)	(MW)	%	(MW)	%
Avista	732.3	12.40%	222	6.70%	222	5.74%
Duke Energy			222	6.70%		
Montana-Dakota Utilities	174.5	2.96%				
NaturEner	210	3.56%				
Northern Lights Cooperative	4.5	0.08%				
NorthWestern Energy	694.4	11.70%	65.5	1.98%	694.4	17.96%
PacifiCorp	271.1	4.59%	152.1	4.59%	271.1	7.01%
Portland General Electric	296	5.01%	296	8.93%	296	7.66%
PPL Montana	1,329	22.50%	1,329	40.10%	1,329	34.38%
Puget Sound Energy	728	12.30%	728	21.96%	728	18.83%
Thompson River Co-gen	16	0.27%			16	0.41%
United Materials	9	0.15%			9	0.23%
Federal Hydroelectric Facilities	1,438.10	24.30%	299.8	9.05%	299.8	7.76%
	5,902.90		**3,314.40**		**3,865.30**	

Figure 4.4.2 Facility Capacity Break-down by Fuel Source (2010)



4.5 NorthWestern Energy's Position

This section will review NorthWestern Energy's historical contracting practices and profile NorthWestern Energy's current energy needs.

With the exception of the small portion of retail loads served by Southern Montana and Electric City, NorthWestern Energy is the only retail supplier that actively must participate in the wholesale electrical market to satisfy its native load obligations. Since June 30, 2002, when PPL's fixed rate under deregulation expired, NorthWestern Energy has utilized several different strategies to acquire electricity in the Montana wholesale electricity market. These consist of securing long-term contract products, some from PPL, market sales and purchases, hedging arrangements, and the soliciting long-term power agreements.

Staff at the Montana PSC have analyzed the price and quantities of energy from 2000-2010, as filed by NorthWestern Energy in its annual supply tracker (Montana PSC, 2011). This analysis only considers net purchases and does not differentiate spot market transactions by seller or location.

Figure 4.5.1 Historical Composition of NorthWestern Energy's Electrical Retail Price

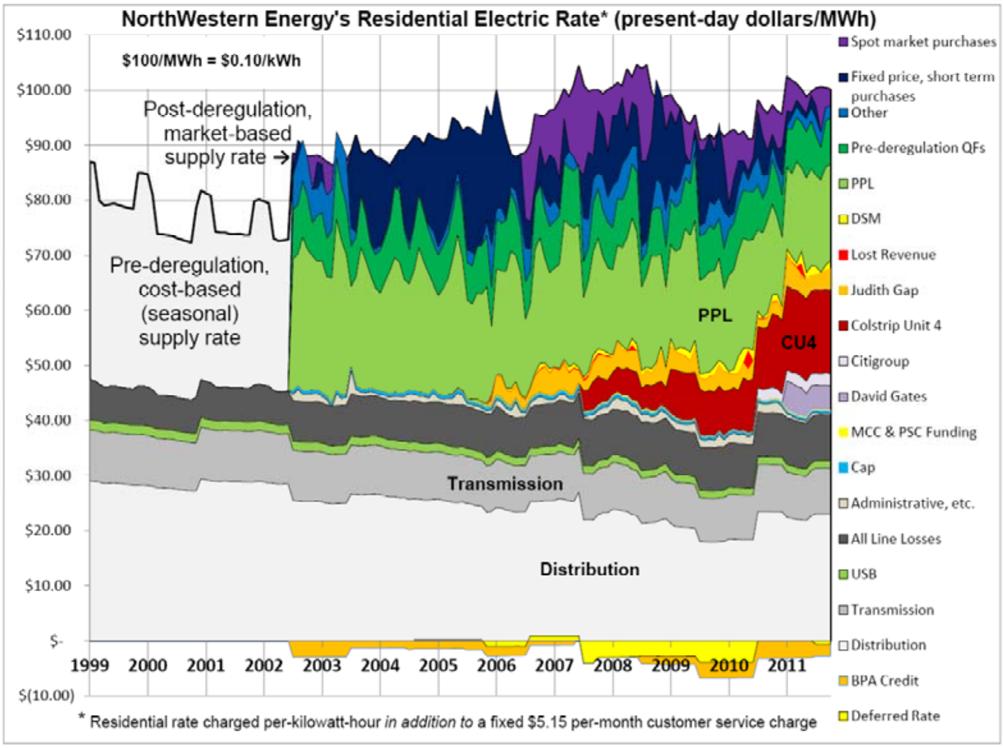


Figure 4.5.2 Historical Composition of NorthWestern Energy's Electrical Retail Quantity

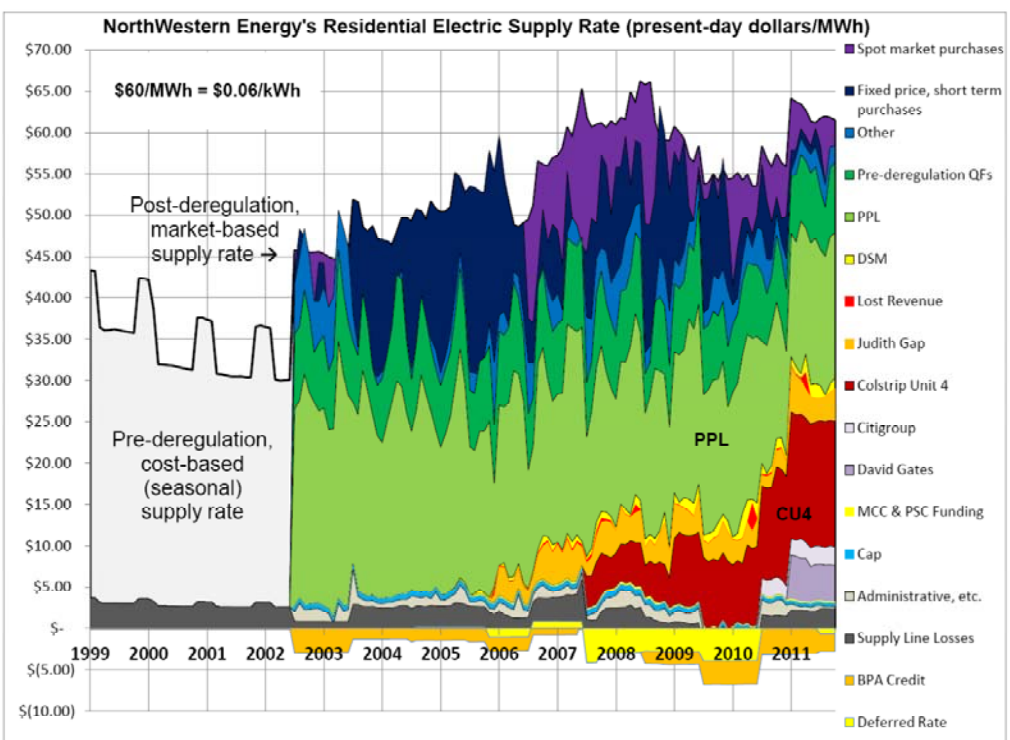
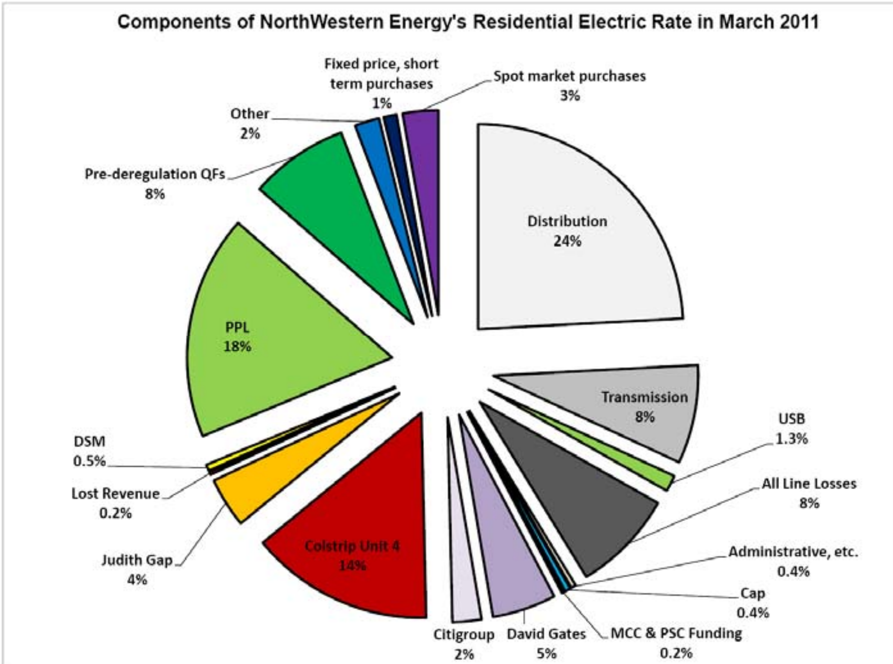


Figure 4.5.3 Composition of NorthWestern Energy's Electrical Retail Price (2011)



Since 2005, NorthWestern Energy has undertaken a number of actions that have collectively minimized reliance on the wholesale electrical market. First, it secured 135 MW of new renewable energy from Judith Gap under a 20 year power purchase agreement with Invenergy that began delivering output in 2005. Second, it acquired 222 MW of Colstrip Unit 4 that started providing electricity in the second quarter of 2007 and subsequently placed this asset in the rate-base in the fourth quarter of 2006. Third, it executed a 20 year contract with the Basin Creek natural gas facility that provides 56 MW of peaking or capacity reserves. Fourth, it completed construction of the 150 MW Mill Creek Generation Station in late 2010. And fifth, it entered several long-term supply contracts, including the Seven Year Contract with PPL that provides 325 MW of on-peak and 175 MW of off-peak electricity with reserves at fixed rates. These actions, in conjunction with other small purchases and

Qualifying Facility agreements, have provided NorthWestern Energy with between 826 and 691 MW of on-peak capacity, depending on Judith Gap's generation level (Table 4.5.1).[109]

The large capacity additions of NorthWestern Energy's re-vertical integration efforts have not been without cost. Some resources, specifically Judith Gap, have provided energy at rates substantially below the Seven Year Contract. However, the largest new energy source, Colstrip 4, carries a 36% premium to the Seven Year Contract. These costs demonstrate that while new capacity additions may mitigate PPL's market power, that they have large independent welfare implications.

Table 4.5.1 NorthWestern Energy's Supply Stack (2008)

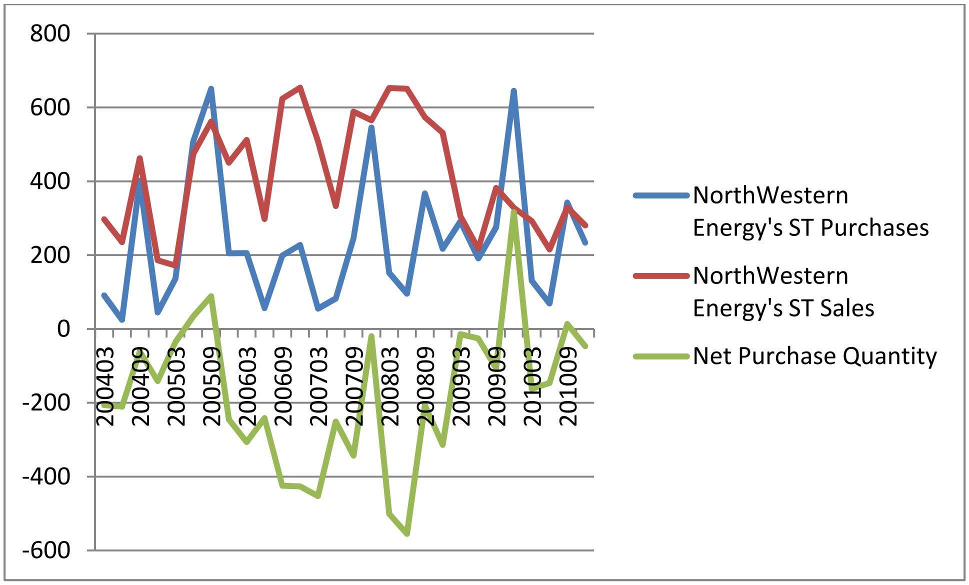
	Price $/MWh	Off-Peak Capacity	On-Peak Capacity	Off-Peak Judith Gap @ 40% Off-peak	On-Peak Judith Gap @ 40% On-peak
135 MW Judith Gap	$46.56 *(1)*	135	135	54	54
6 MW Tiber	$35.94	6	6	6	6
100 MW Tier 1 QF	Varies	100	100	100	100
13 MW, Tier II QF	$45.25	13	13	13	13
325/175MW PPL	$48.95	175	325	175	325
25 MW off-peak Product	$52.45	25	25	25	25
222 MW Colstrip 4	$67.84 *(2)*	222	222	222	222
Total		**676**	**826**	**595**	**745**

(1) With Mill Creek Generation Station Integration Costs
(2) Montana PSC 2011, weighted costs based on actual production

The FERC Dataset provides some additional insight into NorthWestern Energy's purchases and sales. Figure 4.5.4 shows the quantity of NorthWestern Energy's sales and purchases, as reported to the FERC. The data suggests that NorthWestern Energy has been primarily a seller in the wholesale electricity market.

[109] Unless otherwise noted, information provided here is obtained from NorthWestern Energy (2009).

Figure 4.5.4 NorthWestern Energy's Purchase and Sale activity, Short-Term (ST), aMW

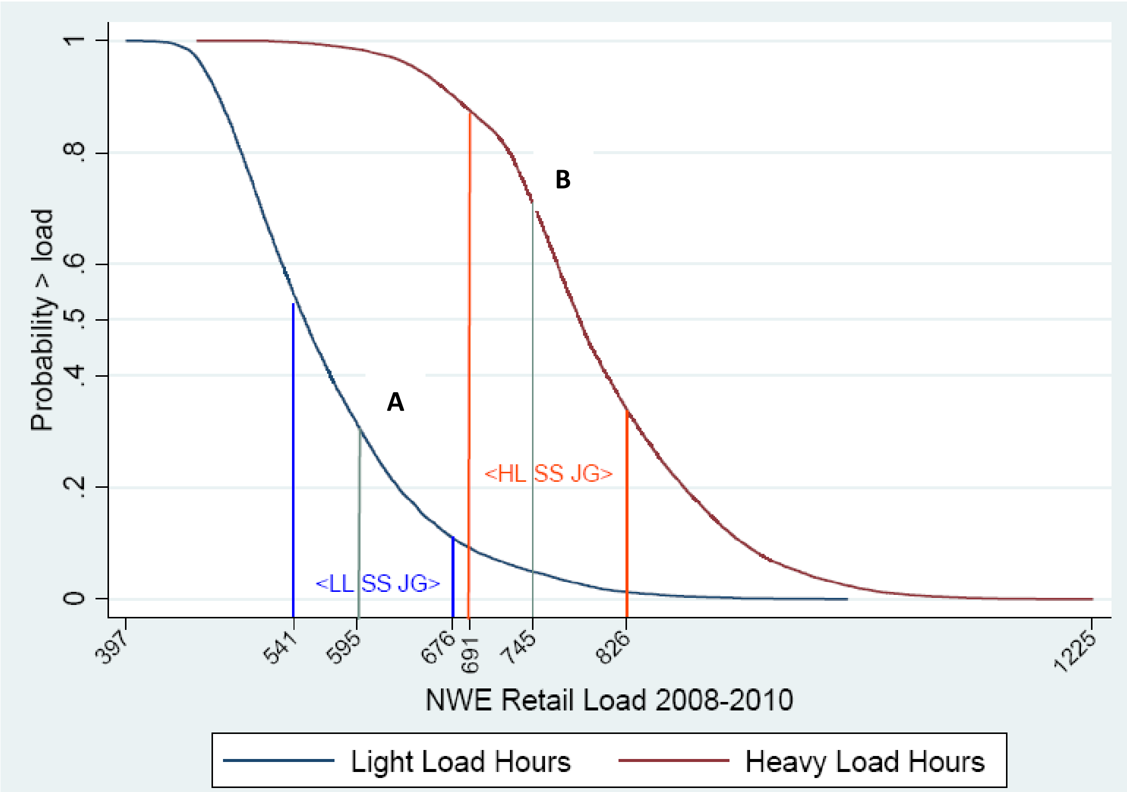


NorthWestern Energy's resource stack is composed of fixed quantity contracts. Most, if not all, of this capacity is provided under must-take contracts, providing NorthWestern Energy little or no capacity, outside the 56 MW associated with Basin Creek, to manage hour-to-hour load variability.[110] Even NorthWestern Energy's share of Colstrip Unit 4, has minimal flexibility, as the output must be coordinated with the other owners of the generation unit. Figure 2.5.5 shows NorthWestern Energy's resource stack in 2008 against its load duration curve, which describes the number of hours in that year that it was required to either to buy or sell electricity to meet its on- and off-peak retail supply obligations.[111]

[110] See NorthWestern Energy's petition in D2011.7.57, where NorthWestern Energy represents that all but one contract associated with its resource stack require it to take delivery of the contracted energy, which is presumed to be Basin Creek. See, http://psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2011-7-57IN11070855295PET.PDF

[111] These curves were calculated with the distplot add-on in Stata using NorthWestern Energy's retail load data provided by Dave Fine. The data is in Pacific prevailing time and reflect Light Load Hours of 10pm-6am, which is assumed to be the same split for NorthWestern Energy's reference on-peak/off-peak contracts. Holidays and weekends were not removed from the curves.

Figure 4.5.5 NorthWestern Energy's High-Load and Light-Load Resource Stack (2008)



NorthWestern Energy's procurement has generally met its average needs through contracts and vertical integration. NorthWestern Energy's peak wholesale demand is 1,225 MW, during heavy load hours, and its minimal load in light load hours is 397 MW. Under average conditions, NorthWestern Energy has procured 595 aMW to meet light load hours and 745 aMW to meet heavy load hours. This procurement allows NorthWestern Energy to satisfy its light-load demand approximately 70% of the time (point A, Figure 4.5.5) and 30% of their heavy-load demand (point B, Figure 4.5.5). With average production from Judith Gap, NorthWestern Energy can meet their light load energy needs 90% of the time, and heavy load energy needs 30% of the time. This implies that NorthWestern Energy will be, on average, selling energy during light-load hours, and purchasing a small amount of energy during heavy-load hours. However, load variation and Judith Gap production will be the primary drivers of purchases and sales. NorthWestern Energy must still make purchase during high demand periods or periods when Judith Gap is not producing.

4.6 Analysis, Montana Model and Lerner Index Calculation

The foundation of the economic models reviewed in section 3.3 is that they capture firm incentives and market constraints to predict price and quantity outcomes in a particular market. A similar approach can be applied to PPL in Montana. This section will develop that model, analyze the results, and also calculate Lerner Index values for PPL.

Neither the Cournot nor Supply Function Equilibrium model is appropriate given the dynamics of the Montana market and the nature of PPL's generation. PPL's capacity is generally fixed, offering it only the option of varying price. PPL is constrained in the price that it can choose by a competitive fringe. The competitive fringe captures all other possible suppliers, either importers into the NorthWestern Energy Balancing Authority Area or the other owners of the Colstrip generation units. The aggregate competitive fringe supply function within the Montana wholesale electricity market is: $P=q_{fringe}*.38 +MIDC*1.37-30$. This supply function was developed through an ordinary least squares regression of the quarterly average prices, quantities, and MID-C prices as provided in the FERC Dataset, and is provided in Appendix III. This sign on quantity implies that supply curve is upward sloping, and linear, with a constant slope of .38. Price also increases with the MID-C price level. A linear demand function may understate actual prices at high demand levels. Joskow and Kahn (2002) in developing a supply function for the California Fringe, assumed a constant elasticity of .33, which would include many of the fringe suppliers to Montana.

Assuming a model where PPL is a monopoly subject to a competitive fringe, there is only one price (p). PPL has 1,137 MW of capacity which it can sell into either Montana or MID-C. If it chooses to sell at

MID-C, PPL incurs a transportation cost of \$3.54 per MWh, Bonneville Power Administration's transmission tariff. The model has the same organization as the Cournot Duopoly defined in Section 3.2, except that PPL will choose price and wholesale demand is fixed (D), and is equal to ($q_{ppl} + q_{fringe}$). The MID-C price is assumed to be determined exogenously (MIDC). The model does not consider any capacity or transmission constraints. PPL's profit definition is π_{PPL}=P*q_{ppl} +(MIDC-3.54)*(1137-q_{ppl}) – C*1,137 , and it faces a residual demand of D - $q_{fringe.}$ The inverse supply function for the fringe is Q_{fringe}=(P+30-MIDC*1.37)/.38. Equation 4.6.1 defines PPL's integrated profit equation, and Equation 4.6.2 defines the first order conditions set equal to zero, based on PPL's selection of price.

Equation 4.6.1 PPL's Profit Equation

π_{PPL}=P*[D-(P+30-MIDC*1.37)/.38] +(MIDC-3.54){1137-[D-(P+30-MIDC*1.37)/.38]}-C*1,137

Equation 4.6.2 PPL's First Order Conditions

P=.19D+.185*MIDC + 16.77

The price is thus conditional on two factors, the MID-C price and demand. As such, the equation can be used to calculate equilibrium conditions for low and high demand levels of NorthWestern Energy, conditional on MID-C price. Table 4.6.1 presents equilibrium conditions for three demand levels, and two MID-C price levels. The conditions are in aMW. The sign and magnitude on the derivative, with respect to price, is reported in Table 4.6.2, which shows the direction, all else constant, that a change in an individual factor will influence price.

Table 4.6.1 Monopoly Model, with Competitive Fringe

MIDC/Demand		100 (aMW)	200 (aMW)	300 (aMW)	400 (aMW)
Price	$40	$43.17	$62.17	$81.17	$100.17
PPL Quantity	$40	48	98	148	198
Fringe Quantity	$40	52	102	152	202
PPL Revenue		$339,656,210	$360,737,150	$398,462,090	$452,831,030
Price	$60	$46.87	$65.87	$84.87	$103.87
PPL Quantity	$60	-14	36	86	136
Fringe Quantity	$60	114	164	214	264
PPL Revenue		$527,767,321	$552,089,461	$593,055,601	$650,665,741

Table 4.6.2 Factor Influences

Derivative	Influence
dD/dP	+.19
dMIDC/dP	+.185

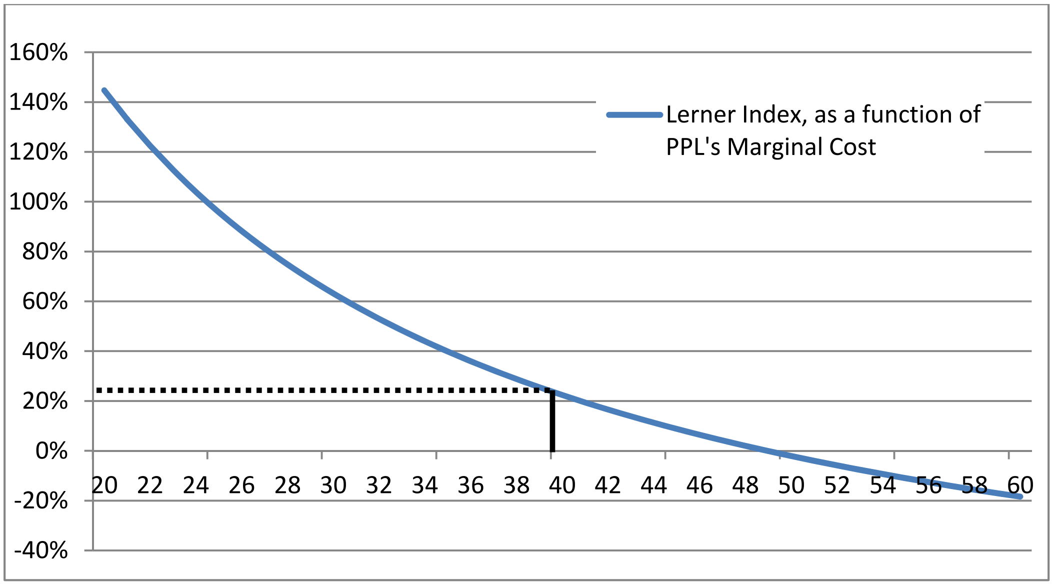
The model predicts that the price will increase, with increases in demand and the MID-C price. The model also demonstrates that even with a fringe with no capacity limits, PPL still has the capacity to set price at values which will deviate from MID-C prices. The model does benchmark well in quantities, but is inflated in price for high demand levels from the observed market data. The revenues predicted by the model are similar to those observed in the FERC Dataset. At the $5.014 billion revenue level captured by PPL's ENERGY and MWh sales, annual revenue would be $716 million, which is similar to the outcomes predicted at the $60 per MWh price level and 400 MW demand level. The model does show that the Montana price will be higher than the MID-C price, which is not observed in the data. However, this may due to the small amount of electricity that NorthWestern Energy is required to purchase with the Seven Year Contract in place.

The model does not account for several factors that may explain divergence from observed prices. First, holding prices at high levels in the long run may lead to additional firm entry in the market, which would depress long-run firm profits. Second, NorthWestern Energy may also have some monopsony power, due to limited firm export transmission capacity from Montana.   Third, there are likely independence problems with the fringe supply curve, which are derived from market observations, ex-post PPL's decisions in the market.

The factor influence on demand provides an initial benchmark to understand the acceptable premium for NorthWestern Energy to pay for vertical integration. In this context, all else constant, vertical integration that removed NorthWestern Energy's market demand by 100 MW would lower the Montana market price by $19. This finding is supported by Bushnell et al. (2006) who identify that vertical integration enhances competitive outcomes in electricity markets. Further they find that in the Pennsylvania organized market that modeled Cournot outcomes would carry a premium by as much as $950 per MWh from the observed pricing (largely determined by vertical integration).

With cost and price information, the Lerner Index can be calculated. Section 4.3 proposes an average cost value for PPL of $40 per MWh. Figure 4.6.1 provides the resulting Lerner index based on the price of the Seven Year Contract between NorthWestern Energy and PPL. At the conservative $40 per MWh average cost value, the implied Lerner Index value for PPL would be 25%, at the lower average cost of $30 per MWh the value would be 65%. There is no bright line rule for converting Lerner Index values to a degree of market power. Borenstein and Bushnell (2009) did see price mark-ups over the competitive benchmarks for Lerner Index values as low as 3%. This suggests that even the conservative Lerner Index calculation of 25% implies some degree of market-power.

Figure 4.6.1 PPL Lerner Index, Function of the Seven Year Contract



4.7 Conclusion

The Montana wholesale electrical market is dominated by PPL. Historical pricing information reveals that PPL can set prices above the Fringe price when selling to NorthWestern Energy and that it receives higher prices from NorthWestern Energy than other buyers within the NorthWestern Energy Balancing Authority Area. PPL's pricing influence has waned over the last three years due to vertical integration by NorthWestern Energy. NorthWestern Energy is now a net seller in the short-term market. The expiration of price caps under deregulation has led to a significant increase in Montana electrical rates, which have been largely absorbed by NorthWestern Energy's customers. Finally, a monopoly model with a competitive fringe explains the quantity allocation seen in Montana, though it suggests higher prices than are observed, which may be due to long-run incentives which are not accounted for in the model.

5: *Conclusion*

5.1 Deregulation was a Costly Failure

The actions by the 1997 Montana Legislature, created lasting problems in the structure and operation of Montana's electrical market. Primarily, electrical prices increased significantly. Using Idaho as a contingent baseline suggests that just between 2004 and 2009, Montanans paid a nominal premium of $722 million. PPL's profits during this period suggest that the premium could have been as high as 2.4 billion. The structure of the Montana wholesale electrical market, and not the structure of the retail market (which was the target of deregulation), is the primary cause of this premium.

The wholesale electrical market in Montana is now comprised of comparatively expensive sources of electricity. These include natural gas facilities, recently rate-based coals plants, and market purchases from outside the state that carry hoteling costs, or transmission wheels. Wholesale competition in the state, to the extent that it exists, has largely meant that the price for electricity is determined independent of the supply and demand structures in the state, and is instead set by the regional price at MID-C and the slope of the supply curve of competing capacity. Assets that used to generate electricity at a small mark-up of their average costs now provide electricity at the market clearing price. The most recent data indicates that the hemorrhaging has stopped, and that efforts by NorthWestern Energy to rebuild a vertically integrated utility are slowly decreasing the compensating Idaho premium.

5.2 Market Power Questions Linger

PPL dominates the resulting industry structure. Some portion of its supply is still necessary for NorthWestern Energy to meet its native load obligations inside its Balancing Authority Area. The FERC's approach to market power regulation is not supported in the economic literature and does not appear to have mitigated PPL's market power in the Montana electricity market. Economic modeling, compensating variation analysis, price mark-up measures, and market data suggests that PPL still has market power. While none of these factors offer conclusive evidence of market power, when coupled with an understanding of firm incentives in electricity markets, they indicate a regulatory failure to adequately mitigate the exercise of market power by PPL.

In the long run, the development of resource in the state may minimize market power concerns. Resource additions from 2006-2010 have been over four times load growth. These resources have carried varying cost structures depending on resource type. Some resources, such as Colstrip Unit 4, have exceeded the cost of the Seven Year Contract with PPL. The Seven Year Contract is also set to expire in 2014, creating a new flashpoint for these issues.

There is also growing potential for regional market structure problems that current regulations may not mitigate. Regional utilities are now depending on the wholesale electricity market to meet portions of their demand, and are using this market to balance increasing generation variability - caused by wind energy development. Unfortunately this market is disorganized, creating information asymmetries and inefficiencies. In the long run this may distort price signals and lead to inefficient transmission and generator development.

Fortunately, there are obvious solutions that are already implemented across the United States called Independent System Operators. By creating an organized market, an Independent System Operator could improve market efficiency through structured auctions that will mitigate market power and enhance reliability. An Independent System Operator can be implemented without any divestiture by regional utilities and without interrupting the long-run welfare benefits of vertical integration.

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Appendix I, FERC Dataset Import Methodology

Steps to use Stat / Transfer to import the FERC Dataset into Stata

1. Download all dataset files and header. The FERC Dataset is currently housed at: http://www.ferc.gov/docs-filing/eqr/data/database.asp.

2. Unzip into same directory, and move all files into the same file folder.

3. Make sure that the machine has Visual Fox Pro Database drivers downloaded and installed.

4. Stat Transfer will transfer by using the “ODBC” file type, pointing to the “EQR.ebc” file that was in the header, and then selecting each of the individual table (year_quarter_Al or MZ). Each table will have to be selected manually.

Appendix II, Montana Table of Generating Capacity

This table was developed from the Energy Information Administration's Project Database.[112]

COMPANY	PLANT	COUNTY	SOURCE	First Year	Nameplate Capacity	Balancing Authority Area[113]
PPL Montana	Madison	Madison	Water	1906	8.80	NWMT
PacifiCorp	Big Fork	Flathead	Water	1910	4.10	NWMT
PPL Montana	Rainbow	Cascade	Water	1910	35.60 (62 in 2011)	NWMT
PPL Montana	Hauser	Lewis-Clark	Water	1911	17.00	NWMT
PPL Montana	Ryan	Cascade	Water	1915	48.00	NWMT
PPL Montana	Thompson Falls	Sanders	Water	1915	87.50	NWMT
Northern Lights Cooperative	Lake Creek A&B	Lincoln	Water	1917	4.50	BPA
PPL Montana	Holter	Lewis-Clark	Water	1918	38.40	NWMT
PPL Montana	Mystic	Stillwater	Water	1925	12.40	NWMT
PPL Montana	Black Eagle	Cascade	Water	1927	24.00	NWMT
PPL Montana	Morony	Cascade	Water	1930	45.00	NWMT
PPL Montana	Kerr	Lake	Water	1938	211.50	NWMT
US Corps - Missouri River Division	Fort Peck	McCone	Water	1943	185.30	WAPA
US BurRec - Pacific Northwest Region	Hungry Horse	Flathead	Water	1952	428.00	BPA
US BurRec - Great Plains Region	Canyon Ferry	Lewis-Clark	Water	1953	49.80	NWMT
Montana-Dakota Utilities	Lewis & Clark	Richland	Lignite Coal/Natural Gas	1958	44.00	WAPA
PPL Montana	Cochrane	Cascade	Water	1958	48.00	NWMT
Avista	Noxon Rapids	Sanders	Water	1959	510.30	AVAT
US BurRec - Great Plains Region	Yellowtail	Big Horn	Water	1966	250.00	NWMT
PPL Montana	J. E. Corette	Yellowstone	Coal	1968	172.80	NWMT
Montana-Dakota Utilities	Miles City	Custer	Natural Gas/#2 Fuel Oil	1972	23.20	WAPA
US Corps - North Pacific Division	Libby	Lincoln	Water	1975	525.00	BPA
PPL Montana	Colstrip 1 (50%	Rosebud	Coal	1975	179.00	NWMT
Puget Sound Energy	Colstrip 1 (50%)	Rosebud	Coal	1975	179.00	NWMT

[112] See, http://www.eia.gov/electricity/data.cfm#generation.
[113] This table assigns the capacity at Colstrip to NorthWestern Energy's Balancing Authority Area.

PPL Montana	Colstrip 2 (50%)	Rosebud	Coal	1976	179.00	NWMT
Puget Sound Energy	Colstrip 2 (50%)	Rosebud	Coal	1976	179.00	NWMT
Montana-Dakota Utilities	Glendive #1	Dawson	Natural Gas/#2 Fuel Oil	1979	34.80	WAPA
Avista	Colstrip 3 (15%)	Rosebud	Coal	1984	111.00	NWMT
PacifiCorp	Colstrip 3 (10%)	Rosebud	Coal	1984	74.00	NWMT
Portland General Electric	Colstrip 3 (20%)	Rosebud	Coal	1984	148.00	NWMT
PPL Montana	Colstrip 3 (30%	Rosebud	Coal	1984	222.00	NWMT
Puget Sound Energy	Colstrip 3 (25%)	Rosebud	Coal	1984	185.00	NWMT
NorthWestern Energy, long-term (QF) - Hydrodynamics	South Dry Creek	Carbon	Water	1985	2.00	NWMT
Avista	Colstrip 4 (15%)	Rosebud	Coal	1986	111.00	NWMT
NorthWestern Energy	Colstrip 4 (30%)	Rosebud	Coal	1986	222.00	NWMT
PacifiCorp	Colstrip 4 (10%)	Rosebud	Coal	1986	74.00	NWMT
Portland General Electric	Colstrip 4 (20%)	Rosebud	Coal	1986	148.00	NWMT
Puget Sound Energy	Colstrip 4 (25%)	Rosebud	Coal	1986	185.00	NWMT
NorthWestern Energy, long-term (QF) - Montana DNRC	Broadwater	Broadwater	Water	1989	10.00	NWMT
NorthWestern Energy, long-term (QF) - Colstrip Energy Partnership	Montana One	Rosebud	Waste Coal	1990	41.50	NWMT
NorthWestern Energy, long-term (QF) - Yellowstone Partnership	Billings Generation	Yellowstone	Petroleum Coke	1995	65.00	NWMT
Montana-Dakota Utilities	Glendive #2	Dawson	Natural Gas/#2 Fuel Oil	2003	40.70	WAPA
NorthWestern Energy, long-term - Tiber Montana, LLC	Tiber Dam	Liberty	Water	2004	7.50	NWMT
Thompson River Co - gen	Thompson River	Sanders	Coal/wood	2004	16.00	NWMT
Montana-Dakota Utilities	Glendive Diesel	Dawson	Diesel	2005	1.80	WAPA
NorthWestern	Judith Gap	Wheatland	Wind	2005	135.00	NWMT

Energy, long-term - Invenergy Wind						
NorthWestern Energy, long-term - Basin Creek Power	Basin Creek	Silver Bow	Natural Gas	2006	54.90	NWMT
NorthWestern Energy, long-term (QF) - Two Dot Wind	Martinsdale Colony S.	Wheatland	Wind	2006	2.00	NWMT
PacifiCorp	Hardin	Big Horn	Coal	2006	119.00	NWMT
United Materials (Idaho QF/NWE QF)	Horseshoe Bend	Cascade	Wind	2006	9.00	NWMT
Montana-Dakota Utilities	Diamond Willow	Fallon	Wind	2007	19.50	WAPA
NaturEner	Glacier 1	Toole	Wind	2008	106.50	GLAC
NaturEner	Glacier 2	Toole	Wind	2009	103.50	GLAC
Montana-Dakota Utilities	Diamond Willow Expansion	Fallon	Wind	2010	10.50	WAPA
NorthWestern Energy	Mill Creek	Silver Bow	Natural Gas	2010	150.00	NWMT
NorthWestern Energy, long-term (QF) - other hydro	Various	Various	Water	Various	2.52	NWMT
NorthWestern Energy, long-term (QF) - other wind	Various	Various	Wind	Various	1.98	NWMT

Appendix III, Supply Curve Estimation

The data provided by the FERC Dataset does allows for a simple estimate of the supply curve of the competitive fringe, based on the average quantity of quarterly supply and the average quarterly price. Consider the model where the Fringe Price $= B_o + B_1(Q_{Fringe}) + B_2(P_{MID\text{-}C})$. The coefficients for the model are: B_o=-30.17, B_1=.38, and B_2=1.37. Regression results are provided in Figure A3.1.1.

Figure A3.1.1, Estimation Results Fringe Supply Curve

Fringe Quantity	0.38
	(1.72)
Mid-C Price	1.37**
	(7.42)
Constant	-30.17**
	(-2.83)
n	27
R-Squared	0.70
F	28.53**
p-value	0.00

t statistics in parentheses
* p<0.05, ** p<0.01