ESSAYS ON GASOLINE PRICE SPIKES, ENVIRONMENTAL REGULATION OF GASOLINE CONTENT, AND INCENTIVES FOR REFINERY OPERATION.

by

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Abstract

Since 1999, regional retail and wholesale gasoline markets in the United States have experienced significant price volatility, both intertemporally and across geographic markets. In particular, gasoline prices in California, Illinois and Wisconsin have spiked occasionally well above gasoline prices in nearby states. The three chapters of my thesis study the relationship between gasoline price spikes, environmental regulation of gasoline content, unanticipated refinery outages and other recent structural changes in the domestic oil market.

In the first chapter, I detail current regulations related to gasoline content. Implemented regionally to address local mobile-source emissions, gasoline content regulations increase costs to refiners, transporters and distributors of gasoline, as well as reduce the fungibility of gasoline across different regions. Chapter one provides a summary of the regulations and a qualitative description the costs the regulations impose on refiners, transporters and distributors of gasoline.

In chapter two, I estimate two distinct effects of gasoline content regulations in California, Illinois and Wisconsin: (i) the effect of increased production costs due to supplementary regulation, and (ii) the effect of incompatibility between these blends and gasoline meeting federal reformulated gasoline standards. Using a structural model based on the production optimization problem of refiners, I simulate wholesale prices for jet fuel, diesel and four blends of gasoline in each geographic market. I then specify a counterfactual in which gasoline in the three states met federal requirements. Using a similar methodology, I also estimate the effect of two structural changes in the domestic oil market, (i) changes in refinery ownership and (ii) limited expansion of domestic refining capacity.

I estimate the effect of increased refining costs is 4.5, 3.0 and 2.9 cents per gallon in California, Illinois and Wisconsin. The effect of incompatibility with federal RFG criteria, conditional on an in-state refinery outage, is 4.8, 6.6 and 7.1 cents per gallon in California, Illinois and Wisconsin. Controlling for the magnitude of local outages in these areas, I estimate that 72, 92 and 91 percent of price spikes created by local refinery outages could be mitigated by compatibility with federal RFG standards.

In chapter three I study the challenge faced by regulators of differentiating strategic withholding of capacity from unreliable production. If a regulator cannot verify "unplanned" outages, the regulator cannot credibly distinguish between strategic behavior by producers and unlucky realizations of facility reliability. I specify a model in which a firm's choices of production and maintenance affect facility reliability and study how incentives arising from ownership of more than one facility affect facility reliability. I then statistically test whether the pattern of incidents is consistent with the predictions of the theoretical model. I find statistically significant evidence that ownership of other local refining capacity is correlated with the probability of an outage at a given refinery. In addition, the relationship between ownership and incident likelihood is greatest for markets with special gasoline formulations, where a refinery outage has the largest effect of gasoline prices. In these markets, expected incident likelihood is 30 percent greater for a refinery affiliated with another refinery that it is for an unaffiliated refinery.

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for my family

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Chapter 1

Product Differentiation In Gasoline Markets: A Discussion of Regional Gasoline Content Regulations

1.1 Introduction

Over the past several years, prices in US retail gasoline markets have fluctuated significantly, punctuated by regional prices spikes in the Midwest and California. The first of these regional spikes to receive significant attention occurred in Spring 2000 in Chicago and Milwaukee, where prices for reformulated gasoline rose from \$1.85 and \$ 1.74 on May 30, 2000 to \$2.13 and \$2.02 a gallon on June 20, 2000 before falling to \$1.57 and \$1.48 respectively by July 24, 2000.[1] In contrast, the national average price for reformulated gasoline over a similar period moved from \$1.64 on May 29, 2000 to \$1.73 on June 19, 2000 and to \$1.66 on July 24, 2000. Similar price spikes occurred in the Midwest in Spring of 2001, and have occurred in California in 2000, 2001 and 2003.

These localized price spikes in US gasoline markets have created interest in understanding the factors underlying retail gasoline prices. In addition, interest also exists

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[1] Final Report of the Federal Trade Commission on the Midwest Price Spikes, March 21, 2001, http://www.ftc.gov/os/2001/03/mwgasrpt.htm.

in identifying factors common across regional gasoline price spikes. For instance, one cause of the high retail gasoline prices in Chicago and Milwaukee in Spring 2000 was reported to be a Citgo refinery fire which "made it difficult to supply major hubs like Chicago and Milwaukee with the special blends of reformulated gasoline that are required by law in those cities."[2] The Federal Trade Commission investigated the production difficulties associated with the Spring 2000 price spike, in an attempt to determine whether or not refineries able to produce reformulated gasoline were withholding capacity to manipulate retail prices.[3] In addition, a recent report by the Senate Subcommittee on Investigations investigates the potential effect of market structure and increasing concentration in many markets on price levels and volatility.[4]

1.1.1 What Drives Gasoline Prices

The studies responding to gasoline prices spikes identified factors that potentially contribute volatile gasoline prices. Gasoline production costs, at a very basic level, are driven by input prices (predominately crude oil prices), the cost to refine that crude oil, and the cost to transport and distribute refined products to retail customers. Moreover, short-run gasoline demand is relatively inelastic. Although consumers are responsive to price competition between retail stations, overall demand for gasoline is not strongly affected by the price of gasoline.[5] This creates the potential for significant

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[2] Barboza, D., "Gasoline Prices Jump in Midwest, Hinting of Wider Price Spike", New York Times, August 30, 2001.

[3] See Final Report of the Federal Trade Commission, Midwest Gasoline Price Investigation, March 29, 2001. http://www.ftc.gov/opa/2001/03/midwest.htm.

[4] See "Gas Prices - How Are They Really Set?", Majority Staff of the Permanent Subcommittee on Investigations, Released in Conjunction with the Permanent Subcommittee on Investigations' Hearings on April 30 and May 2, 2002.

[5] Recent estimates cited in Sipes and Mendelsohn (2001) of short-run elasticities vary from -0.35 to -0.51 and of long-run elasticities vary from -0.73 to -0.87. In addition, Dahl and Sterner (1991) perform a meta-analysis across previous studies and calculated mean short-run price elasticities of -0.26 and mean long-run price elasticities of -0.86 in studies with panel data. A more recent meta-analysis performed by Espey (2001) finds that mean and median short run elasticities of -0.26 and -0.23.

volatility in gasoline prices, either in response to fluctuations in production costs, low inventories caused by supply shocks or market power by refiners and wholesale dealers.

Over the past twenty years, three trends within the industry may have contributed towards higher gasoline prices and more frequent price spikes. One significant change has been a trend toward decreasing reserve refining capacity. In 1981, annual refinery production was 68 percent of operable refinery capacity. Over the past twenty years, the utilization rate for refining capacity increased dramatically - as old refineries were closed, no new refineries were built in response to rising demand for refined products.[6] A second trend has been the general consolidation of the industry during the late 1990's. Mergers in the petroleum industry include British Petroleum and Amoco in 1998, Exxon and Mobil in 1999 and BP/Amoco and Arco in 2000.[7] Although regulatory approval for each merger required divestiture of overlapping refining assets, changes in ownership may still affect gasoline prices. Third, state and federal regulation of gasoline content increased differentiation of gasoline products or "blends". Motivated by concerns about air pollution, the EPA and individual states have stipulated a variety of regulations aimed at reducing the emissions from gasoline-powered motor vehicles by specifying the gasoline content.

This paper focuses on the last of these trends, the trend toward greater regulation of gasoline content. Increasingly incompatible gasoline content regulations affect gasoline prices in several important ways. First, content criteria impose costs not only on refineries, but also on transporters and distributors of petroleum products. In order to meet content regulations at the retail level, not only must gasoline be sufficiently refined to meet the regulations, but it must be transported and stored without being intermixed with other "blends". Second, since some content regulations must be met though gasoline additives, gasoline supply becomes susceptible to supply shocks in additive markets. Finally, content regulation reduces the fungibility of gasoline, that

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[6] See Dazzo, N., Lidderdale, T., and N. Masterson, "U.S. Refining Capacity Utilization," Energy Information Administration, Petroleum Supply Monthly.

[7] See "Gas Prices - How Are They Really Set?", Majority Staff of the Permanent Subcommittee on Investigations, Released in Conjunction with the Permanent Subcommittee on Investigations' Hearings on April 30 and May 2, 2002 at pg 3.

is, fewer refiners produce gasoline for regions with specific regulations. Not only does this increase the potential for tacit collusion among refiners of a specific blend, but it also increases the impact of unexpected outages on the supply of particular blends. If a small set of refineries are producing a particular blend of gasoline, an outage to any refinery in that set could lead to a large change in production, so long as significant supply adjustment costs exist at the refinery level, limiting the extent to which refiners adjust in the short run. In addition, since content regulations reduce the substitutability of different "blends" of gasoline, it may be difficult to compensate for a drop in production capacity by reducing inventories. Anecdotal evidence supporting the relationship between product differentiation of gasoline and regional price volatility is that the areas experiencing the most drastic prices changes in the past several years, namely Chicago, Milwaukee and California, most strictly regulate gasoline content.

This paper first addresses, in Section II, the nature of refining, with an emphasis on the elements related to gasoline content regulation. Section III provides a summary of the history and implications of important federal and state regulations pertaining to gasoline content. In Section IV, the paper discusses the potential direct and indirect effects of content regulation, as mandated by federal and state governments, on the price levels and volatility of gasoline. Finally, Section V discusses the analyses performed to-date of the potential effect of content regulation on price levels, volatility and market power concerns. Section VI concludes.

1.2 Refining Process

To understand how gasoline content regulation affects the refining of crude oil, it is necessary to understand refinery operation. The primary task of an oil refinery is to separate crude oil into a wide variety of petroleum products, from gasoline to industrial fuel to road tar. Crude oil is a mixture of different hydrocarbons, with between 1 and 60 carbon atoms per molecule, and amounts of other compounds containing sulfur, nitrogen and other elements.[8] Hydrocarbons are classified by weight, that is, the number of carbon atoms per molecule. Generally, the weight of a molecule predisposes a hydrocarbon to a particular application. For example, gasoline contains "lighter" products, with between 4 and 12 carbon molecules, while industrial No. 6 Fuel Oil is made up of "heavier" petroleum products with more carbon atoms per molecule. The role of the refinery is threefold: (1) isolate "lighter" and "heavier" intermediate streams, (2) remove impurities, such as sulfur, and improve the quality of the intermediate streams, and (3) blend the intermediate streams together to create end-products with valuable properties.

It is important to note, though, that refiners have considerable flexibility when processing crude oil. Through choices of input crude and the method of refining, individual refiners can influence the achievable output mix. This section first discusses how the choice of crude oil affects the output mix of a refiner and then addresses how the equipment at a refinery can affect the mix of final products.

1.2.1 Choice of Crude Oil

The choice of crude oil is the first way a refiner can influence output mix. Crude oil from different locations is a heterogeneous good. Based on the chemical makeup of the crude oil, a particular refinery is limited in the blend of petroleum products it can produce. Two standard metrics for differentiating crude oil are the API gravity weight of the oil and the sulfur content.[9] The API gravity weight of oil is correlated to the relative proportion of shorter strings of hydrocarbons ("lighter" components) to long strings of hydrocarbons ("heavier" components). This relative proportion of light and heavy components dictates, at a basic level, the set of products a refinery can product through simple distillation. If a refinery distills heavy oil, it will produce a greater

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[8] An in-depth discussion of the components of crude oil and gasoline can be found at http://www.faqs.org/faqs/autos/gasoline-faq/part1/preamble.html.

[9] Alternative metrics to API gravity degrees include specific gravity and density. See http://pump.net/thebasics/equivdegrees.htm for a table translating API gravity into alternative metrics.

proportion of industrial products like fuel oil and coke than if a refinery distills light oil. Thus, depending on the desired mix of end products and the technology of the refinery (discussed in the next section), a refiner may choose to refine light or heavy crude oil based on forecasted market prices.

The characteristics of the crude oil not only affect the proportions of the products produced, but also the amount of processing that is required to transform the oil into various products. For example, sulfur content specifies how much sulfur a particular barrel of oil contains. Low-sulfur crude is termed "sweet" and high sulfur crude is termed "sour". Refining sour oil, requires additional processing to remove sulfur from end products to meet environmental or industrial standards. For example, fuel oil sold for industrial use becomes more valuable as the sulfur content decreases.

1.2.2 Refinery Technology

Technology at refineries also allows a refiner to influence the mix of end-products produced. Most refineries have several different types of equipment that allow the refiner to separate, alter and purify the various components of crude oil. The basic operating unit at any refinery is the distillation tower. The distillation unit separates crude oil into component parts by heating the oil until the crude oil evaporates. The evaporated crude oil is piped to the distillation tower where the oil begins to rise through a series of filters. The temperature of the evaporated crude oil decreases as it passes through each filter. Since "heavy" hydrocarbons condense at higher temperatures than "light" hydrocarbons, the "heavy" hydrocarbons condense more quickly than lighter components.[10] By siphoning off the condensed material at each of the different filters, the distillation tower roughly separates the crude oil into "light" components and "heavier" components.[11]

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[10] Generally, components from lightest to heaviest are butanes, naphtha, kerosene, distillate, vacuum distillate and residua.

[11] The technology of the distillation tower affects the ability of a refiner to separate crude oil. Distillation units which operate in a vacuum separate crude oil more effectively than "atmospheric" distillation units.

Although the gravity of oil determines the petroleum products created through distillation, refineries also have equipment that can adjust and improve the mix of end products after distillation. Three post-distillation units present at most large, modern refineries are the (1) catalytic, thermal and hydro crackers, (2) reformers, and (3) hydrotreaters. Cracking units adjusts the mix of outputs by "cracking" long chains of hydrocarbons into shorter ones. This changes heavier products, like fuel oil, into lighter and more valuable products like distillate and naphtha. With simple distillation, approximately forty percent of crude oil can be made into light products. The chemical properties of light products are more valuable than those of heavy products - under most circumstances, refiners crack as much heavy product into light product as possible, given the existing capital at a refinery.

Unlike the cracking unit, which alters the proportions of the output mix, the reformer and hydrotreater improve the quality of intermediate streams, which are then blended into finished products. The reformer changes the structure of naphtha molecules without changing the number of hydrocarbons. Reforming changes low-octane molecular structures into high-octane molecular structures (e.g. benzene), which can then be blended into gasoline to improve quality. Hydrotreating also improves products by removing impurities - in most cases sulfur - from a product. Since the quality of crude oil affects the processing required, many refineries were built to use local crude supplies.

Although the choice of crude oil drives what end products will be created, these technologies allow a refinery to alter the final mix of products to a degree. For example, simple distillation of a barrel of West Texas Intermediate crude oil yields about 4/10 of a barrel of gasoline and 6/10 of a barrel of other petroleum products. Cracking and reforming allow a barrel of crude to be separated into 2/3 of a barrel of gasoline and 1/3 of a barrel of heating oil.[12] In addition, depending on which components of a barrel of crude oil are cracked, reformed or hydrotreated, a refinery has considerable flexibility in adjusting the set of products in response to changes in

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[12] Refiners and marketers often refer to the 3:2:1 crack spread - three barrels of crude can be made into two barrels of gasoline and one barrel of heating oil.

expected end-product prices.

1.2.3 Production Runs

While a refinery has considerable flexibility in manipulating and improving petroleum products, planning must occur prior to refining due to the interconnected nature of refining, cracking and reforming. In addition, the logistics for transporting and purchasing crude oil and for transporting finished products require preparation. Since it is costly to adjust inputs and output mixes on a day to day basis, refineries operate around "production runs". Production runs are generally three to six weeks in length, during which refiners hold input and output mix relatively constant. Planning for a production run, begins two to three months in advance, when refiners contract for crude oil with particular properties.[13] Based on price forecasts, the refiner chooses the set of outputs which maximize expected profit. As the production run gets closer, the refiner finalizes the inputs. Just prior to the run, engineers finalize the planned output mix, based on costs of inputs and updated expected prices of refined products. After a production run begins, significant changes to production require the refinery to reduce production and reconfigure the system of distilling, cracking, reforming and hydrotreating.

1.3 Environmental Regulation of Gasoline

1.3.1 Clean Air Act Amendment of 1990

The Environmental Protection Agency (EPA) regulates the chemical content of motor fuels through Section 211 of the Clean Air Act (CAA), passed as part of the Clean Air Act Amendment of 1990 (CAAA). Specifically, Section 211 grants the EPA the power to "control or prohibit the manufacture, introduction into commerce, offering for sale, or sale of any fuel or fuel additive for use in a motor vehicle, motor vehicle engine or non-road engine or non-road vehicle" based on the emissions and health

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[13] Report of the Federal Trade Commission, Midwest Price Spike Investigation, March 29, 2001.

consequences caused by a particular fuel.[14] These regulations define both what must be removed during the refining process and what can or must be added to the fuel, prior to retail sale. Section 211 encompasses all regulations (1) specifying content of fuels, such as sulfur limits on diesel fuel, (2) prohibiting additives, such as restrictions on lead anti-knock agents in gasoline, and (3) mandating additives, such as detergent requirements.

Five regulations in Section 211 outline specific requirements for motor gasoline: (1) limitations on lead-based antiknock agents, (2) mandated detergent additives, (3) limitations on the Reid Vapor Pressure, (4) mandated oxygen content, and (5) the content of reformulated gasoline (RFG).[15] To understand the potential impact of each of these programs, Table 1.1 presents a three-part taxonomy, encompassing geographic scope, temporal scope and method of implementation. The first element is the geographic scope of the program. Like many regulations, some content regulations apply nationally, while others apply only to particular regions. Regulations (1) and (2) apply nationally, while (4) and (5) apply, by law, only to specified non-attainment areas specified by the EPA. Program (3) contains both regional and national components, placing a national requirement for all gasoline, and in addition, mandating more stringent requirements for non-compliance areas. A second classification is the temporal scope of the program. Due to the influence of temperature and sunlight in the generation and formation of air emissions, certain programs apply seasonally, while others apply year-round. Specifically, (1), (2), and (5) are year-round programs, while (3) and (4) apply only seasonally. The final categorization is the method of implementation of the regulation; that is, whether the regulation necessitates a processing change by refiners or can be met with an additive added after the standard refining process is complete. Programs (1), (2) and (4) can be met by additives alone, while (3) and (5) require refinery-level adjustment.

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[14] Clean Air Act, Section 211 (c)(1)

[15] Section 211 also mandates requirements for diesel fuel, such as sulfur limits.

1.3.2 National Programs

Prohibition on Leaded Anti-knock Agents

The first, and perhaps most well-known, national regulation of gasoline content is the prohibition on leaded anti-knock agents imposed by the EPA starting January 1, 1986.[16] Since the 1920's, lead compounds were added to gasoline to increase octane rating and to reduce the tendency of gasoline to "knock" or prematurely ignite when compressed in an engine. Citing the known health effects of lead-based anti-knock agents, the EPA began in 1973 to compel refiners to use non-leaded anti-knock additives by slowly ratcheting down the acceptable lead content limits of gasoline. The process culminated in 1986, when the EPA standard placed a nationwide limit of 0.1 gram per gallon on the amount of lead in gasoline, in contrast to the previous limit of 1.1 gram per gallon. EPA regulation eventually ended the sale of leaded gasoline in the United States.

Detergents

A second national program mandated by the CAAA of 1990 required refiners to add detergents to gasoline beginning in January 1, 1995.[17] Detergents reduce the accumulation of deposits in engines which decreases fuel efficiency and increase emissions. Although the program is a national, year-round one, states have flexibility in the choice of detergent additives, so long as they meet or exceed the emissions standards defined by the EPA.

1.3.3 Regional Programs

In addition to the national regulations focused on phasing out lead-based antiknock agents and limiting fuel system buildup in cars, the CAAA created three regional programs: Low Reid Vapor Pressure gasoline, oxygenated gasoline and reformulated

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[16] "EPA Sets New Limits on Lead in Gasoline", EPA press release, March 4, 1986. http://www.epa.gov/history/topics/lead/01.htm

[17] Clear Air Act, Section 211(l)

gasoline. The objective of the three programs was to reduce air emissions from gasoline-powered engines. The objectives of oxygenated gasoline and reformulated gasoline, in particular, were to reduce emissions in carbon monoxide or ozone non-attainment areas. Non-attainment areas fail to meet EPA guidelines for air quality based on ozone and carbon monoxide (CO) concentration. Two important allowances of the CAAA contribute to the effect of each of these regional programs. First, states and regions not required to participate in regional programs can "opt-in" to a program and voluntarily adopt the EPA requirements. This increases the geographic scope of oxygenated gasoline and reformulated gasoline significantly.[18] Second, the CAAA only mandates minimum standards gasoline must meet. This allows cities and states to impose more strict standards than the required federal standards.

Reid Vapor Pressure

The first of the regional programs, focusing on reducing ground-level ozone pollution, is a cap on the Reid vapor pressure (RVP) of gasoline.[19] Reid vapor pressure measures the propensity of gasoline to evaporate, and increases with the amount of "light" petroleum chains (eg. benzene or butane) in gasoline. In order to lower the RVP of gasoline, it is necessary for refiners to filter out the lightest components, which have the lowest boiling point and evaporate most easily. Limitations placed on gasoline RVP reduce the amount of "fueling" pollution, evaporation that occurs as a gas tank is filled. This significantly reduces the release of volatile organic compounds (VOCs) and to a smaller extent the release of nitrogen oxides (NOx), which are both precursors to ground-level ozone pollution. Since ground-level ozone formation is positively affected by both temperature and sunlight, ozone formation is only a problem during the summer. Thus, the RVP program is a seasonal program, in contrast restrictions on lead anti-knock agents and required detergent additives. In most cases, the "ozone season" begins May 1 and ends September 15. It is only over

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[18] For example, populations of opt-in areas constitute over 1/3 of the total population of all areas mandating reformulated gasoline.

[19] Clear Air Act, Section 211(h)

this period that the refiners are required to limit the vapor pressure of gasoline.

Phase I of the RVP regulations, effective Summer 1989, mandated a regional limits varying from 10.5 psi to 9.0 psi based on the region of the country. Phase II, effective Summer 1992, placed a national cap of 9.0 psi on gasoline RVP. To address the regional variation in the severity of ozone pollution, the RVP requirements for Phase II were more strict in ozone non-attainment areas. For non-attainment areas, Phase II requirements varied from 7.8 psi to 7.0 psi throughout the summer ozone season. In addition, in some locations requirements varied from month to month during the ozone season, depending on the severity of the ground-level ozone pollution. In addition, many areas tightened RVP requirements beyond the standards set by the EPA. For example, Pheonix, Arizona has a state-placed limit of 7.0 psi which runs through September 30 each year, rather than the federally-mandated September 15.[20]

The final note to make about Low RVP regulation is that reformulated gasoline regulations place a limit on the benzene content of gasoline (although not RVP). In many cases, the benzene limit is more restrictive than the RVP cap and, thus, RFG regulations currently supersede Low RVP regulations in many metropolitan areas of the country. Thus, RVP regulations currently only apply to areas which do not participate in the reformulated gasoline program.[21]

Oxygenated gasoline

The second regional program, effective November 1992, was intended to increase the oxygen content of gasoline sold to consumers.[22] Whereas reducing RVP lowers VOC and NOx emissions, oxygenating gasoline enables an engine to burn gasoline more completely, reducing Carbon Monoxide (CO) emissions. Once again, the method of implementation, the temporal scope and geographic scope provide a starting point from which to understand the potential effects of this regulation.

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[20] US Environmental Protection Agency, Guide on Federal and State RVP Standards for Conventional Gasoline Only, EPA420-B-01-003, March 2001.

[21] See US Environmental Protection Agency, Office of Mobile Sources, "Guidance on Use of Opt-in to RFG and Low RVP Requirements in Ozone SIPs," April 1, 1999.

[22] Clean Air Act, Section 211(m)

Unlike the Low RVP requirements that can only be met through processing at the refinery, refiners use additives to increase the oxygen content of gasoline. The baseline EPA requirement calls for 2.7 percent oxygenation by weight - this requirement can be met by blending in one of several additives that increase oxygen content. The two most common oxygenates are methyl tertiary butyl ether (MTBE) and ethanol. In order to achieve the 2.7 percent baseline set by the CAAA, refiners or distributors must either blend in15 percent MTBE, derived from natural gas, or 8 percent Ethanol, derived from renewable feedstocks such as corn stover or cellulose.

Like Low RVP regulation, baseline EPA requirements to oxygenate fuels have a seasonal component. Carbon monoxide emissions from mobile sources are greatest during the winter, as cold engines emit greater amounts of carbon monoxide. However, ethanol increases the RVP of gasoline, and hence is detrimental to efforts focused on reducing summer ground-level ozone pollution. While CAAA does not specify outright a seasonal schedule for oxygenation, simply mandating a minimum duration of four months per year, the EPA mandates winter oxygenation for all areas in CO non-attainment. In general, refiners and distributors must oxygenate gasoline from November through February.[23]

The geographic scope of the regulation has two important facets: (i) the areas required to participate and (ii) state-level supplementary regulation mandating oxygenation requirements. First, unlike Low RVP requirements, no national oxygenation requirements exist - only regions with in CO non-attainment must oxygenate gasoline. The CAAA initially required oxygenated gasoline for 39 areas considered to be in CO non-attainment for 1988 and 1989, as specified by the National Air Ambient Quality Standards (NAAQS). The initial 39 non-attainment areas included CMSAs containing 87.5 million people. In addition, any region that failing to attain the NAAQS standard for CO, must begin oxygenation during winter months specified by the EPA.

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[23] For a comprehensive list of temporal requirements facing particular areas, see Lidderdale, Tancred; Areas Participating in the Oxygenated Gasoline Program; Energy Information Administration, July 1999, Short-Term Energy Outlook Special Report. http://www.eia.doe.gov/emeu/steo/pub/special/oxy2.html.

Moreover, several areas in attainment, such as Portland, OR and Tuscon, AZ, voluntarily opted in through state-mandated programs. As regions reach attainment, though, oxygenated gasoline is no longer required. Of the original 39 non-attainment areas, areas containing approximately 46 million of the original 87.5 million people have since come into CO attainment and have "opted out" of the oxygenated gasoline program.

While the EPA mandates a baseline of 2.7 percent oxygen by weight and specifies a seasonal duration of the program for each area, the areas themselves may constraint refiners' choice of oxygenate and may impose more stringent requirements than those mandated by the EPA. In the case of oxygenation, additional regulation is much more pervasive than in other programs. While some areas have imposed more stringent oxygenation requirements (e.g. WA, NV, AZ all require 3.5 percent oxygen consistent with blending 10 percent ethanol with gasoline) and more stringent temporal requirements (MN requires year-round oxygenation), the greatest amount of differentiation between state programs is generated by requirements over the choice of oxygenate. Due to the need for a renewable feedstock (generally corn stover) to produce ethanol, ethanol is used as an oxygenate in the Midwest while MTBE is used primarily in the Northeast and California.[24]

Finally, several other aspects of oxygenation programs deserve mention. First, like Low RVP regulations, reformulated gasoline has somewhat supplanted oxygenated gasoline. The basic RFG formula specified by the CAAA requires 2 percent oxygen by weight, which in many areas is sufficient to meet NAAQS standards. Currently, only reformulated gasoline sold in New York City area must be oxygenated during the winter beyond RFG requirements. Also, the CAAA also grants the EPA the ability to provide a waiver from the 2.7 percent oxygen requirement for states where "the use of oxygenated gasoline would prevent or interfere with the attainment by the area

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[24] California plans to phase out MTBE by December 31, 2002 due to health concerns. California Executive Order D-5-99, March 25, 1999. http://www.energy.ca.gov/mtbe/index.html. In addition, twelve other states have passed legislation to reduce or eliminate the use of MTBE as an oxygenate. See "Gas Prices - How are they really set?" at 69.

of a national primary ambient air quality standard for any air pollutant other than carbon monoxide."[25] Due to the additional volatility of oxygenated gasoline which hampers efforts to reduce ground-level ozone, California restricts oxygen content to 1.8-2.2 percent.

Reformulated Gasoline (RFG)

The final regulation of gasoline content mandated by the CAAA is reformulated gasoline.[26] The most comprehensive legislation to control emissions through gasoline content, reformulated gasoline targets both NOx and VOC emissions (like Low RVP regulation) and CO emissions (like oxygenated gasoline). The method by which RFG reaches these goals is different from both oxygenated gasoline and Low RVP regulations. Like the low RVP and oxygenation requirements, RFG regulation stipulates explicit content criteria. The content requirements are similar to those stipulated by the Low RVP regulation and oxygenation regulation - benzene is limited to one-percent of total volume and oxygen content must be at least two percent of weight. Thus, the content requirements are essentially a combination of the Low RVP requirements and the oxygenation requirements. Unlike low RVP and oxygenation regulations, RFG regulation also specifies "performance" standards, which are emissions-based measurements that refiners have flexibility in meeting. The three "performance" standards specify reductions of VOC emissions, NOx emissions and toxic air pollutants (TAPs) emissions relative to the 1990 gasoline that must be met by gasoline sold as RFG. Performance requirements allow refiners to improve gasoline emissions in the least-cost manner. RFG regulations also contain "anti-dumping" restrictions for refiners. These prevent refiners from simply shifting gasoline components that they would like to remove from reformulated gasoline to their conventional gasoline.

Like RVP regulation, RFG standards have phased in over time, with the performance standards becoming more strict in the second Phase. Phase I, effective

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[25] Clean Air Act, Section 211(m)(3)

[26] Clean Air Act, Section 211(k)

January 1, 1995, necessitated reduce VOC and TAP emissions by fifteen percent as part of the performance standards as well as meet content standards for benzene and oxygenation. In addition, NOx emissions from reformulated gasoline could not exceed those from the baseline 1990 gasoline. Phase II, effective January 1, 2000, required twenty-five percent reductions in VOC and TAP emissions in addition to the content standards. The NOx emissions are unchanged from Phase I to Phase II. Thus, standards for reformulated gasoline became more stringent over time.

Once again, the taxonomy helps identify how the content regulation may affect refining and distribution. RFG is a regional, year-round requirement - the CAAA initially required sale of reformulated gasoline in the nine severe ozone non-attainment areas with 1980 populations in excess of 250,000. These nine areas (Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia and San Diego) constitute over 63 million people, or twenty-four percent of the total US population. In addition to these nine cities, any area reclassified as severe non-attainment is required to shift from conventional to reformulated gasoline. For example, Sacramento was reclassified as a severe ozone non-attainment area in the summer of 1995 and was required to use reformulated gasoline beginning January 1, 1996.

Like other content regulations, though, areas in attainment can "opt-in" to the reformulated gasoline program, adopting the content and performance requirements for gasoline. While opt-in slightly increased participation in oxygenated gasoline and Low RVP gasoline regulations, RFG opt-in areas greatly expanded the geographic scope of RFG regulation. Since 1995, regions containing approximately 35 million people have adopted the RFG content and performance regulations.[27]

While standards do not vary across different regions participating in the federal RFG program (California's program will be discussed in the next section), participating regions can and do stipulate the use of particular oxygenates. Consistent with the pattern of oxygenate use for oxygenated gasoline, reformulated gasoline in the

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[27] For a comprehensive list of areas subject to RFG regulation, see http://www.epa.gov/otaq/rfgarea.htm.

Midwest is usually oxygenated with ethanol, while areas on the East and West coasts traditionally oxygenate gasoline with MTBE.

CARB Gasoline

The final major regional gasoline content regulations are those promulgated by the California Air Resources Board (CARB) regulating gasoline sold year-round in California.[28] Beginning in 1992, California began a three phase state-run program regulating gasoline content. Content regulation in Phase I of the California program, effective January 1, 1992, was consistent with federal low RVP and oxygenated gasoline programs introduced at the time, with the exception that California mandated oxygen content of 1.8 - 2.2 percent by weight as opposed to the federal standard of at least 2.7 percent oxygen by weight.

Phase II CARB gasoline replaced Phase I CARB gasoline in March 1996. CARB Phase II regulations were similar to the federal regulations for reformulated gasoline introduced in 1995. Like RFG regulation, most Phase II CARB regulations were effective year-round (with the exception of the Low RVP limit). Phase II regulations lowered the RVP limit from 7.8 psi to 7.0 psi, limited benzene content to 1 percent by volume and mandated 1.8 to 2.2 percent oxygen content by volume. California regulations covered the entire state, essentially opting-in areas already in ozone and CO attainment (mainly Northern California). One significant difference, though, between the CARB requirements and EPA RFG requirements was a limitation placed on sulfur content of gasoline by CARB. CARB Phase II requirements stipulate a flat limit of 40 ppm sulfur on all gasoline. As discussed in the earlier section on refining, sulfur naturally occurs in crude oil and, when untreated, occurs generally at concentrations of approximately 250 ppm in gasoline. This sulfur limit requires either skimming off high-sulfur gasoline into the less valuable distillate pool or hydrotreating the gasoline to remove sulfur during the refining process. In addition, CARB regulations only imposed specific content requirements, unlike the relative "performance" standards of federal RFG.

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[28] Title 13, California Code of Regulations, Sections 2250-2273.

Phase III CARB, going into effect for producers December 31, 2002 and for retailers March 31, 2003, tightened limits on sulfur content to a flat limit of 20 ppm and on benzene content to 0.8 percent by volume. In addition, phase III CARB gasoline also prohibited the use of oxygenates other than ethanol to eliminate the use MTBE due to health concerns.[29] Citing fears of costly gasoline and the additional volatility of ethanol, which leads to greater evaporative emissions of VOCs and NOx, Governor Davis has appealed to EPA to waive the oxygenation requirement for California's compliance with federal "minimum" RFG standards.[30]

From Gasoline to "Boutique Blends"

In 1991, gasoline across the country met similar content standards for lead and other metals. In the past 10 years, environmental regulation has significantly changed the substitutability of gasoline across different areas. Currently, there are fifteen "boutique fuels", each satisfying content constraints for regional content requirements.[31] Increasing differentiation began in 1992, when national Phase II RVP limits lowered gasoline volatility nationwide and summer RVP limits were placed on gasoline sold in ozone nonattainment areas. In addition, in 1992, California instituted phase I CARB gasoline. That winter, oxygenation of gasoline was required in CO non-attainment areas. Like the RVP limits, required duration varied by noncompliance area. Some areas in compliance opted-in to each of these programs, increasing participation. In addition, various cities and states mandated stricter content requirements, specified the use of particular oxygenates and lengthened the period of compliance.

Starting January 1, 1995, year-round reformulated gasoline requirements supplanted seasonal RVP limits and oxygenation requirements for the nine metropolitan

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[29] California Executive Order D-5-99, March 25, 1999. http://www.energy.ca.gov/mtbe/index.html. In addition, twelve other states have passed legislation to reduce or eliminate the use of MTBE as an oxygenate. See "Gas Prices - How are they really set?" at 69.

[30] "Governor Davis Sues US EPA Over Gasoline Additive", August 13, 2001. http://www.arb.ca.gov/cbg/oxy/wav/oxywav.htm.

[31] Study of Unique Gasoline Fuel Blends, Effects on Fuel Supply and Distribution and Potential Improvements, US Environmental Protection Agency. Appendix D.

areas in severe ozone nonattainment. Once again, a significant number of areas in attainment chose to adopt reformulated gasoline requirements. With the exception of California, EPA regulations permitted regions to mandate the use of particular oxygenates. While choice of oxygenates has little effect on refining when gasoline must only meet a minimum oxygen content, different oxygenates have different properties. In order to meet "performance requirements" for NOx and VOC emissions, RFG must be refined differently if it is going to be blended with ethanol or MTBE. Thus, although the requirements for RFG are consistent across program areas with the exception of California, choice of oxygenate has an impact on refining.

Effective March 1996, the California Air Resources Board tightened EPA requirements for reformulated gasoline, introducing both a summer RVP limit (on top of the benzene limit in RFG) and a limit on sulfur content as part of the Phase II CARB gasoline requirements. In addition, to other requirements Sulfur limits required for gasoline sold in California further differentiated California gasoline from federal RFG sold in other areas.

More strict standards for reformulated gasoline (Phase II RFG) went into effect January 1, 2000. In addition, Phase III CARB gasoline further tightened requirements in California starting December 31, 2002. Thus, in a under a decade, the US gasoline market became considerably more differentiated. In summary, Table 1.2 contains a breakdown of the various content requirements imposed by the EPA and state regulations. Table 1.3 details the geographic and temporal scope of reformulated gasoline, oxygenated gasoline and CARB gasoline programs.

1.4 Costs of Gasoline Content Regulation

Adherence to gasoline content regulation increases the cost of gasoline directly. Costly additives, such as ethanol, raise the average cost of producing a gallon of gasoline. In addition, additives meant to reduce pollution dilute gasoline, lowering the energy content and reducing fuel efficiency of automobiles. Moreover, content regulations can affect costs associated with production, transportation and storage of gasoline. Low

RVP, reformulated and CARB regulations force refiners to refine gasoline more than they otherwise would, increasing production costs. Regulation of gasoline content also imposes other costs on production and distribution of gasoline due to the inflexible nature of refining, storage and transportation of gasoline.

The goal of this section is to identify how gasoline content regulation could affect the price levels and price volatility of gasoline. This section first discusses the direct costs of additives and the impacts of regulations on fuel efficiency. After addressing these primary costs, potential costs imposed on refining, transportation and storage infrastructure are summarized for the major regional content regulations: RVP limits, oxygenation, RFG and CARB gasoline.

1.4.1 Direct costs of environmental regulation

Cost of oxygenation additives (Ethanol/MTBE)

The most direct cost imposed by content regulation is the cost of additives required to meet certain fuel specifications. Oxygenation standards drive the majority of this type of cost, since either 8 percent ethanol or roughly 15 percent MTBE must be blended into gasoline to meet the 2.7 percent oxygen by weight minimum for oxygenated gasoline. Since reformulated gasoline and CARB Phase II and III also stipulate a minimum oxygen content, albeit lower than that required for oxygenated gasoline, oxygenate costs also play a role in the prices for each of these types of gasoline.[32] Historically, gasoline prices on a per gallon basis have been lower than MTBE prices which have in turn been lower than ethanol prices. Hence, requiring oxygen be added to gasoline most directly affects production costs by increasing the average cost of the components constituting a gallon of gasoline.[33]

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[32] California sued the EPA over their application for a waiver for CARB Phase III gasoline from federal RFG minimum oxygen content requirements. http://www.arb.ca.gov/cbg/oxy/wav/oxywav.htm

[33] Gasoline blended with 10 percent ethanol (gasohol) is exempt from 5.4 cents of federal gasoline tax. In addition, this exemption is prorated for gasoline containing less than 10 percent ethanol. This translates into a 54 cent per gallon subsidy of the production and use of ethanol. Even with

On top of the simple cost of oxygenates, mandating an oxygen content level also introduces an additional input subject to production disruptions. While MTBE is generally produced at petroleum refineries, ethanol plants located in the Midwest produce the vast majority of US ethanol. Depending on inventory levels of ethanol and transportation costs, unexpected outages of ethanol plants may affect the supply of ethanol and hence ethanol-blended gasoline. On top of the effect of unexpected outages, production of ethanol is even more concentrated than crude oil refining. Thus, stipulating an oxygen content level and especially stipulating a particular oxygenate could lead to higher and more volatile gasoline prices.

Lower Fuel Efficiency

A less obvious effect of content regulation is an alteration of the energy content of gasoline. By limiting certain petroleum products and requiring certain additives, content regulation changes the amount of energy contained in a volume of gasoline, thereby affecting mileage of cars. The two requirements which substantively affect energy content are RVP limits and oxygenation. The RVP cap on gasoline limits the volume of highly volatile petroleum products. These products contain relatively less energy by volume than less volatile products - as a result, RVP limits increase energy density in gasoline. In addition, since less fuel is lost through evaporation when fueling, a 1 percent decrease in benzene levels roughly corresponds to a 0.25 percent increase in engine efficiency. Adding oxygenates to gasoline, on the other hand, dilutes the gasoline by adding lower energy density oxygenate. Due to the greater percentages of oxygenates used, meeting EPA oxygenated gasoline requirements leads to a 2 to 3 percent loss in engine efficiency. Reformulated and CARB gasoline, with oxygen content and volatility limits, fall somewhere in between, with 1 to 2 percent efficiency losses.[34]

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this subsidy, though, historical ethanol prices have been higher than MTBE prices.

[34] For more information about the effect of content regulation of efficiency, see Lidderdale, T., "Environmental Regulations and Changes in Petroleum Refining Operations", Energy Information Administration, June 1998.

It is important to note, though, that both of these also affect the volume of gasoline produced. For example, if gasoline is blended with ethanol, 100 gallons of gasoline and 8 gallons of ethanol create 108 gallons of oxygenated gasoline. Thus, although oxygenation reduces the energy content for each gallon of gasoline, the reduction in energy content per gallon is compensated for by increasing the total volume. Hence, the energy content of gasoline is not lost through oxygenation, but merely spread over a greater number of gallons. Unless significant costs are associated with filling gas tanks such that a 3-4 percent energy loss, and consequently an increase of similar magnitude in the frequency of filling tanks, is significant, reductions in energy content only need only be considered when comparing price levels of conventional gasoline with price levels of various gasoline blends.

1.4.2 Refining costs

The nature of crude oil refining drives how gasoline content regulation affects the refining industry. The primary effect of gasoline content regulation (specifically Low RVP, reformulated gasoline and CARB gasoline) is the necessary increase in the refinement of gasoline. That is, content regulation forces refiners to refine gasoline more than they otherwise would in order to meet various standards.

Specifically, limits on the RVP of gasoline impose costs on refiners, since RVP can only be reduced at the refinery level. Gasoline, like any petroleum product is made up of a blend of different elements. To lower the RVP, it is necessary to isolate and remove the components of gasoline which are the most volatile and hence most prone to evaporation. This increases refiner production costs through additional refining costs to remove these components as well as processing costs of these and other components in order to maintain the volume of gasoline.

Likewise, reformulated gasoline regulation requires increased refining to remove volatile components in gasoline. Although RFG requirements do not specify a particular RVP limit, they do constrain benzene levels at a maximum of 1 percent of total volume. In addition, the VOC and TAP performance standards force refiners to remove volatile elements of gasoline. This places a constraint similar to the RVP limit, forcing refiners to separate benzene and other volatile elements from the gasoline. Furthermore, state-mandate use of ethanol as an oxygenate places additional costs of meeting the performance standards, to offset different chemical properties of ethanol and MTBE. For example, the RVP of ethanol is higher than the RBP of MTBE (18.0 psi versus 8.0 psi).[35] Although ethanol's higher oxygen content allows for it to be blended in lesser proportion to gasoline to meet oxygen content requirements, it nonetheless increases the RVP of gasoline by about 1 psi when blended to satisfy the requirements of RFG. Refiners required to use ethanol must remove more benzene and other volatile components from the gasoline so the blend satisfies the performance standards for NOx and VOCs.

CARB regulations cap the volatility of gasoline and require oxygenation, creating similar costs for refiners producing CARB gasoline to costs for refiners producing reformulated gasoline. In addition, CARB gasoline also must not exceed a set sulfur content. This forces refiners to either remove sulfur from gasoline by hydrotreating or using more expensive low-sulfur crude.

To understand the effect of refining constraints imposed by content regulation, I separate the effects into two categories: (1) those for which adjustments can be made during the next production run and (2) those which require investment by a refiner. For example, small adjustments in Reid vapor pressure can be easily made through changes in the refining process. Once a refiner has produced low RVP gasoline, no major investment is required to blend the gasoline with MTBE, and still meet RFG performance requirements. However, if the gasoline must be blended with ethanol, refiners must invest in order to produce gasoline with extremely low volatility. While these investments are not extremely costly, only refiners serving RFG markets requiring ethanol as an oxygenate made the investments prior to the start of Phase II RFG. Other refiners "have not made such facility changes because they have little reason to undertake these changes for the markets they traditionally serve."[36] Similarly, refin-

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[35] See Gomez J., T. Brasil and N. Chan, "An Overview of the Use of Oxygenates in Gasoline", California Air Resources Board, September 1998. http://www.arb.ca.gov/cbg/oxy/oxy.htm.

[36] Shore, J., "Supply of Chicago/Milwaukee Gasoline, Spring 2000", Energy Information Administration, Petroleum division

ers producing CARB gasoline must hydrotreat large quantities of gasoline to remove sulfur. While many refineries already can hydrotreat significant amounts of diesel fuel, many do not have the capacity to also hydrotreat large amounts of gasoline.

The effect of national and state-specific content regulation has been to separate the homogenous gasoline market of 1991 into smaller gasoline "islands", each of which is a small market for gasoline satisfying particular content requirements. Whether or not refiners can adjust their production process from one production run to the next determines the ability of the refining industry to adjust to production shocks in the sub-markets. In the case of ethanol blended RFG or CARB gasoline, refinery investment or substantial production costs limit the number of refiners not regularly serving those markets that can respond to supply shocks within those markets. Due to the costs involved to producing either CARB gasoline or an RFG blend to be mixed with ethanol, California and Chicago/Milwaukee are the best examples of gasoline "islands".[37]

With a greater number of markets and fewer refiners fully committed to each market, content regulation has the potential to both increase industry vulnerability to refinery outages and increase the potential for refiners in a particular sub-market to exercise market power. In fact, both of these have been proposed as contributing factors to the gasoline price spikes in the Midwest in 2000 and in California in 2001. With fewer refiners able to adjust production to meet the specifications of particular gasoline blends, unplanned outages for maintenance contributes to greater price volatility. In addition, to the extent that certain refineries are more efficient than others, necessary investment may lead a less efficient refinery (say in Chicago) to increase production in the event of a fire at a larger Midwest refinery when, but-for the content regulation, a larger refinery in the Gulf Coast might have increased production. In addition, if it is difficult for refineries to switch between the production of different blends, less competitive pressure is brought to bear on markets with relatively few

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[37] See Statement of John Cook, Director, Petroleum Division USDOE Energy Information Administration before the Committee on Energy and Commerce, Subcommittee on Energy and Air Quality, US House of Representatives, May 15, 2001.

refiners. Each of these problems only becomes more acute as reserve refinery capacity decreases over time, as it has been over the last 20 years.

In summary, content regulation has several distinct effects on refining that could increase gasoline price levels and volatility. The most direct method is from the cost of the additional refining necessary to meet to content standards of a particular blend. If adjusting refining processes to meet different criteria was costless, no additional costs would be imposed on refiners. In actuality, significant costs exist, either from investment necessary to meet content standards or from the adjustment costs associated with altering the production plan in the midst of a production run. These costs create gasoline "islands", smaller markets served by a small group of refineries. Since it is costly, in many cases, for refiners to switch from producing one blend to another, even at the end of a particular production run, content regulation also has the potential to influence price levels and volatility by magnifying the effects of an unexpected refinery outage or by reducing the competitive pressure on small groups of refiners producing a particular blend of gasoline.

1.4.3 Transportation costs

Content regulation for gasoline also has ramifications for the transportation of gasoline from refiners to wholesale terminals, after which the gasoline is distributed to retailers. Gasoline is transported to wholesale terminals either through pipeline or by barge depending on the locations of the refinery and terminal. In order to ensure that shipped fuel meets specification both before and after transportation, different blends of gasoline must not mix to a great degree. This is relatively easy to do using barges but becomes more difficult using a pipeline which must be full of product in order to operate. As is the case with different grades of gasoline, pipelines are often filled with higher quality (lower emission) product first and lower quality (higher emission) product second. With many different refineries and many different locations requiring gasoline, transportation costs may increase as a result of content regulation.

On top of additional transportation costs incurred when transporting the gasoline, RFG, CARB and oxygenation regulations also necessitate transportation of additives.

While refiners often produce and mix MTBE with gasoline at the refinery, refiners cannot do this when blending with ethanol for two reasons. Ethanol is produced through sugar fermentation and distillation, which does not happen at the refinery. Also, and more importantly, chemically ethanol is has an affinity for water.[38] If ethanol mixed with gasoline comes into contact with water, the ethanol will separate from the gasoline and combine with the water. Sufficient water exists in product pipelines such that refiners cannot mix gasoline and ethanol at the refinery and then transport the blend. Instead, the operator of the wholesale terminals must blend ethanol with gasoline at the wholesale terminal. This requires ethanol to be transported to wholesale terminals rather than refiners. This becomes more costly as the number of areas requiring ethanol to be blended with gasoline increases. For example, California's prohibition on the use of MTBE as an oxygenate went into effect December 31, 2002. Under the federal oxygen content regulations for RFG, California will need 660 million gallons of ethanol annually. With year to date US production averaging 128 thousand barrels per day, this amounts to roughly one-third of current US ethanol production.[39] Not only must this be produced, but it must also be transported to wholesale terminals in California and blended there.

1.4.4 Storage costs

The final way content regulation can affect the price level and volatility of gasoline via infrastructure is through additional storage costs. Depending on the specific regulation, several potential costs might exist. Clearly, additive-induced transportation costs imply analogous storage costs. Regardless of who blends the additives with the gasoline, storage must exist for the additives at that location as well as the machinery

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[38] See Gomez J., T. Brasil and N. Chan, "An Overview of the Use of Oxygenates in Gasoline", California Air Resources Board, September 1998 for chemical characteristics of oxygenates used in gasoline.

[39] Energy Information Administration, EIA-819M, Monthly Oxygenate Telephone Report, Table B1, August 2002.

to blend additives into gasoline.[40] In addition, as is the case with different grades of gasoline, different content blends must be stored separately. For instance, if a wholesale terminal sells several "blends", it needs separate tanks to maintain content and "performance" requirements of the gasoline. Not only does this create costs for facilities that store several types of gasoline, but it also reduces regional storage capacity for either "blend" which potentially affects market response to supply shocks. Finally, storage costs can also arise due to the seasonal nature of some content regulations, since tanks must be either drained fully or filled several times before stored gasoline will meet specifications. As a result, both retailers and wholesale distributors draw down gasoline levels in storage tanks significantly prior to seasonal changes in gasoline content requirements. While this does not impose any storage costs, in itself, it does draw down inventories, making retail prices more susceptible to shocks.

1.5 Past Literature on the Effect of Gasoline Content Regulation

In August 2001, the head of the Environmental Protection Agency (EPA), Christie Whitman, suggested that "limiting the number of 'boutique blends' to three or four formulas could increase fuel supplies and help prevent large spikes in the prices drivers see at the pump."[41] Despite recognition of the potential effects of content regulation on gasoline price levels and volatility, relatively little empirical work has assessed the effects of content regulation on prices and the ability of refiners and wholesalers to wield market power. No work was found to empirically address the effect of any form of content regulation on price volatility. Nor has any work looked at the effect of decreasing reserve refinery capacity. In addition, none of these analyses attempt to empirically identify which factors, discussed in the previous section, increase or decrease price levels. This section summarizes the work looking at the effect of content

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[40] California terminals' inability to store and blend large amounts of ethanol was noted in CARB report, "An Overview of the Use of Oxygenates in Gasoline". September 1998.

[41] "EPA mulls limiting number of special gasoline blends", The Associated Press, 8/6/01

regulation first on price levels and then looks at investigations of market power.

1.5.1 Literature on Price Levels

Papers evaluating the effect of content regulation on price level can be categorized into ex-ante estimates and ex-post analyses. Ex-ante estimates generally focus on the incremental costs to refiners from producing various blends of gasoline, and occasionally estimate the overall effect on prices. The ex-post analyses empirically quantify the actual effect of content regulation on retail or spot price levels.

Ex-ante estimates

EIA and EPA studies provide the majority of ex-ante estimates of the costs of various content regulations. Prior to the start of oxygenated gasoline regulations, EIA estimated the additional cost of oxygenates would lead to a three to five cent increase in the spot price of oxygenated gasoline relative to conventional gasoline.[42] In 1994, EIA performed a similar analysis for Phase I and Phase II reformulated gasoline. For Phase I RFG, EIA estimated up to a four cent differential between spot prices of conventional and reformulated gasoline.[43] For Phase II RFG, EIA estimated that compliance with Phase II regulations would not add to the price premium in the winter, but would add between 1 and 1.5 cents relative to Phase I RFG during the summer. This was based on the expectation that refiners would be able to comply more easily with Phase II regulations during the winter, when volatility was less of a concern. Based on these estimates and the observed wholesale price premium of 2.5 cents between Phase I RFG and conventional gasoline, EIA estimated a price premium of 2.5 cents during the winter months and 3.5 to 4 cents during the summer months.[44] The EIA estimates were roughly consistent with EPA estimates for Phase

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[42] Lidderdale, T., "Demand, Supply and Price Outlook for Oxygenated Gasoline," Energy Information Administration, Short-Term Energy Outlook, June 1992.

[43] Lidderdale, T., "Demand, Supply and Price Outlook for Reformulated Motor Gasoline 1995," Energy Information Administration, Short-Term Energy Outlook, July 1994.

[44] Bohn, A., and T. Lidderdale, "Demand and Price Outlook for Phase II Reformulated Gasoline, 2000," Energy Information Administration, Short-Term Energy Outlook Update, April 1999 to

I RFG - the EPA initially estimated Phase I reformulated gasoline would lead to additional costs of three cents per gallon. In addition, they estimated that CARB gasoline regulations would create additional costs of eight to eleven cents per gallon.[45]

Ex-post analyses

Several studies by the EPA and one academic article evaluate the ex-post effects of the first several years of content regulation. It is important to note, though, that no study attempts to isolate the effect of content regulation controlling for either increasing industry concentration or changes in refining reserve capacity. Since the time frame for each study is relatively small and prior to most significant industry consolidation, though, these issues are likely to be relatively small.

Lidderdale performs an ex-post analysis of the wholesale price premium for Low RVP gasoline, oxygenated gasoline and RFG at major supply and refining centers. Specifically, for each content regulation he averages spot or wholesale prices over the relevant season on an annual basis. He uses this average as an estimate for the price premium in the wholesale market. In addition, for seasonal programs such as Low RVP regulation and oxygenated gasoline, Lidderdale begins his averaging window one month early to account for the transportation lag between spot markets and retail markets, where content specifications must ultimately be met.[46]

Lidderdale finds that for summer seasons from 1993 through 1998, waterborne Gulf Coast spot prices for 7.8 psi RVP unleaded regular gasoline annually averaged between 0.33 cents and 0.79 cents higher that 9.0 psi RVP gasoline at the same location. Using a similar methodology, Lidderdale finds that for the three winter seasons from 1992-1993 to 1994-1995, the price premium for wholesale, oxygenated

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August 1999.

[45] US Environmental Protection Agency, "The Case for California Reformulated Gasoline - Adoption by the Northeast", Office of Policy, Planning and Evaluation, May 1993.

[46] The averaging window for Low-RVP gasoline and oxygenated gasoline is April 1 through August 31 and October 1 through February 29 respectively in contrast to EPA mandate that generally requires Low RVP gasoline from May 1 through September 15 and oxygenated gasoline from November 1 through February 29.

gasoline at New York Harbor and the Gulf Coast annually averaged between 2.9 and 7.0 cents. The annual average reformulated gasoline price premium at the same locations from 1995 through 1998 varies between 1.9 cents and 3.5 cents. The price premia are, as expected, highly correlated with the price differential between MTBE and conventional gasoline. Lidderdale performs a similar analysis of wholesale price premia for CARB gasoline and finds that from January 1997 to December 1998, the average pipeline spot premium for CARB gasoline relative to conventional gasoline was 4.2 cents in Los Angeles and 4.3 cents in San Francisco.

Vita addresses the affect of divorcement regulation, preventing integration of refiners and retailers, on gasoline prices from 1995 through 1997.[47] Using a panel of average monthly retail prices net of taxes for each state, he regresses price in a particular month for a particular state on demand variables, cost variables and regulatory variables, capturing whether or not a state had divorcement regulation. Included in his model specification as cost-shifting variables, though, are variables indicating the percentage of gasoline sold meeting oxygenated and RFG requirements. In addition, he includes a dummy variable for California after May 1, 1996, to capture the affect of CARB gasoline, and interacts it with a 1997 year-dummy to control if costs of producing CARB gasoline have fallen over time.

Depending on how his regression is specified, Vita estimates a retail price premium of 0.55 to 1.21 cents per gallon for a state required to oxygenate all of their gasoline relative to a state using strictly conventional gasoline. His estimates also imply a 1.52 to 2.18 cent retail premium for CARB gasoline, holding all else constant. Interestingly, the estimation of the effect of reformulated gasoline on price levels is the opposite of the expected effect. He estimates a state requiring reformulated gasoline pays 0.19 to 0.35 cents per gallon less than a state with conventional gasoline.

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[47] Vita, M., "Regulatory Restrictions on Vertical Integration and Control: The Competitive Impact of Gasoline Divorcement Policies", Journal of Regulatory Economics, 18:3 217-233, 2000.

1.5.2 Price Spikes and Price Volatility

The gasoline "price spikes" of the last several years prompted three investigations into the behavior of refiners and market participants, an investigation by the FTC of the price spikes in the Midwest during 2000, a similar investigation by the FTC into gasoline pricing in Western States, and an report by the US Senate Subcommittee on Investigations. In addition, the DOJ has studied antitrust concerns in the market for ethanol production. While the investigations focus on whether or not explicit collusion among participants occurred, each investigation discusses the role that content regulation may play in creating the price spikes.

FTC Midwest Price Spike Investigation

After the retail gasoline price spikes in Chicago and Milwaukee during May and June 2000, the FTC began an investigation of the behavior of market participants leading up to the price spikes.[48] The FTC found that while market participants may have unilaterally acted in their best interest, there was no evidence of explicit collusion by firms to manipulate the retail price, and hence no violation of antitrust statutes. Evidence suggested that "prices rose both because of factors beyond the industry's immediate control and because of conscious (but independent) choices by industry participants."[49] As part of the report, though, the FTC did identify three primary factors in the price spike, namely, refinery production problems, pipeline disruptions and inadequate inventories. Of the factors identified by the FTC, several can be traced to content regulation. First, content regulation complicated the production of Phase II RFG (especially that produced for Chicago and Milwaukee requiring ethanol), as refiners had difficulty meeting the new standards for Phase II. In addition, the requirement to use ethanol as an oxygenate in Chicago and Milwaukee reduced the ability of other refineries to substitute MTBE-blended Phase II RFG for the Chicago and Milwaukee blend. Finally, in order to meet the Phase II RFG standards, refiners

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[48] Final Report of the Federal Trade Commission, Midwest Gasoline Price Investigation, March 29, 2001.

[49] See Executive Summary of Final Report of the FTC.

and wholesale distributors needed to drain tanks to prevent Phase II compliant and non-phase II complaint gasoline from commingling. This led to low inventories, increasing the susceptibility of the industry to reduced pipeline availability and delays bringing refineries back from maintenance.

FTC Western Price Investigation

In addition to the FTC investigation of the Midwest price spikes, the FTC also investigated the production and distribution practices of major refiners in the Western states of Arizona, California, Nevada, Oregon and Washington.[50] Again, the FTC found no evidence of explicit collusion between refiners. Once again, though, the FTC investigation identified "unique product requirements, such as gasoline satisfying California Air Resources Board standards" as an important factor contributing to the differences in price between the gasoline market in the West and in the rest of the US.

US Senate Subcommittee Investigation

The final, and largest, investigation was a US Senate Subcommittee investigation addressing "whether the increased concentration has contributed to the price spikes and increases."[51] The goal of this investigation was not to ascertain whether or not explicit collusion had occurred, but rather to evaluate the factors underlying the retail price spikes of the last several years. The findings of the subcommittee identify both increasing concentration and declining reserve capacity as factors underlying the retail price spikes of the last several years. While they noted "the current gasoline production and distribution system is able provide adequate quantities of boutique fuels," they also remarked that "in the event of a supply disruption or shortage, it may be more difficult to bring in additional supply to an area that requires a boutique fuel rather than a conventional fuel, because fewer refiners may be readily capable of pro-

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[50] See Statement of Commissioners Anthony, Swindle and Leary Concerning Western States Gasoline Pricing Investigation. May 7, 2001.

[51] See "Gas Prices - How Are They Really Set?" at pg 17.

ducing the required gasoline."[52] In addition, the investigation specifically identifies seasonal storage transition issues as a contributor to the Midwestern price spikes of 2000 and 2001. Thus, although the investigations of the FTC and Senate Subcommittee do not attempt to quantify the effect of content regulation, they do acknowledge that content regulation has played a role in recent price spikes.

1.6 Conclusion

To address the increased volatility of gasoline prices over the past several years, three important industry trends must be incorporated into any analysis. First, over the past ten years, the industry has significantly consolidated. While consolidation was conditional on divestiture of overlapping refining and retailing assets, significant refining resources have been purchased and sold. While apriori the effect of consolidation with divestiture is ambiguous, this must be nonetheless incorporated into any analysis. Second, since the early 80's, refining capacity has not increased at the same rate as demand. As in the case of the electricity industry, reserve refining capacity provides backup refining in the case of unexpected refinery outages. Depending on the degree to which inventories and the transportation system are able to compensate for unexpected outages, this may or may not play a role in the high gasoline prices of the past several years. Thus, declining reserve refining capacity also must be taken into account in any analysis of gasoline pricing. Finally, federal and state regulations now mandate distinct blends of gasoline for different regions of the country. These regulations have the potential to impose significant costs on refineries, pipelines and storage terminals. Moreover, content regulations reduce the fungibility of gasoline across different, but often nearby, areas. This reduces the ability of refiners and marketers to substitute gasoline between locations in response to unforeseen supply and demand shocks. It is these regulations which at least at first glance, are the most directly related to price volatility since over the past several years, the two regions with the most volatile gasoline prices have both had a unique blend of gasoline.

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[52] See "Gas Prices - How Are They Really Set?" at pg 74-75.

The effects of each of these trends have clear policy implications. Almost 130 billion gallons of gasoline were sold at the wholesale level in the United States during 2000.[53] To the extent that any of these trends creates a cost that is avoidable (e.g., through standardization of content regulation), large potential savings exist. In addition, if the goal of content regulation is to reduce air pollution in particular areas, it is also informative to determine whether content regulation represents a relatively efficient or inefficient way of reaching that goal. A number of existing and potential policy tools, including fuel-economy regulation, vehicle emissions standards, emission-based registration fees, and premature vehicle retirement, could substitute as a policy tool for reducing air emissions. An important question, given the potential costs of content regulation, is whether alternative policies provide a more cost-effective method of reducing local emissions.[54] Alternatively, if significant effects are traced to declining reserve capacity, other policy tools could potentially address those costs. The quantification of the effects and evaluation of the relative efficiencies of the policies provides a question and focus for future research.

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[53] EIA Petroleum Marketing Annual, 2000, Table 48.

[54] See Harrington, Walls and McConnell (1994) for estimates of the cost-effectiveness of various policies to reduce motor vehicle emissions.

Table 1.1: Regulations Pertaining to Gasoline Additives

Regulation	Geographic Scope	Seasonality	Method of Compliance	Notes
Lead Anti-knock Agents	National	Full Year	Use of Other Antiknock Additives	
Detergents	National	Full Year	Additives	
Phase II Reid Vapor Pressure	National	Summer Ozone Season	Refining	National Component: 9.0 psi limit
Phase II Reid Vapor Pressure	Regional	Summer Ozone Season	Refining	Regional Component: 7.0 - 7.8 psi limit generally
Oxygenation	Regional	Winter	Additives	Period and Additives vary by location
Reformulated Gasoline	Regional	Full Year	Additives and Refining	
CARB Gasoline	California Only	Full Year	Additives and Refining	

Table 1.2: General Specifications of Gasoline Blends*

Specification	National RVP Limit	Low RVP Limit	Oxygenated Gasoline	RFG Phase I	RFG Phase II	CARB Phase I	CARB Phase II	CARB Phase III
Scope								
Retail Implementation Date	1-May-92	1-May-92	1-Nov-92	1-Jan-95	1-Jan-00	1-Jan-92	1-Mar-96	31-Mar-03
Temporal	May 1 - Sept 1	May 1 - Sept 15	Nov 1 - Feb 29	Year-Round	Year-Round	Summer/Winter**	Year-Round	Year-Round
Geographic	National	Regional	Regional	Regional	Regional	Parts of California	California	California
Content Regulation								
RVP	9.0	7.8	-	-	-	7.8	7.0	7.0
Oxygen Content (% weight)	-	-	2.7 % min	2.0 % min	2.0 % min	1.8 % - 2.2 %	1.8 % - 2.2 %	1.8 % - 2.2 %
Benzene Content (% volume)	-	-	-	1.0 % max	1.0 % max	-	1.0 % max	0.8 % max
Sulfur Content (ppm)	-	-	-	-	-	-	40.0	20.0
Performance Standards								
NOx Reduction	-	-	-	0.0%	0.0%	-	-	-
VOC Reduction	-	-	-	15.0%	25.0%	-	-	-
TAP Reduction	-	-	-	15.0%	25.0%	-	-	-

*Note: Some regional programs have more strict regulations or slightly different control periods.

** Oxygenation requirement must be met during the winter while RVP requirement must be met during the summer.

Table 1.3: Regional Gasoline Content Regulations*

				Annual Control Period		
Area	Content Regulation	Date Effective	Redesignation/ Opt-out Date	Seasonal Start Date	Seasonal End Date	Area Specific Notes
Albuquerque, NM	Oxygenated	1-Nov-92	13-Jun-96	Nov. 1	Feb. 29	
Albuquerque, NM	Oxygenated	13-Jun-96		Nov. 1	Feb. 29	State Mandated Program, currently requires ethanol oxygenation
Anchorage, AK	Oxygenated	1-Nov-92		Nov. 1	Feb. 29	Anchorage program suspended until 1999/2000 winter season, currently requires ethanol oxygenation
Baltimore, MD	Oxygenated	1-Nov-92	31-Oct-95	Nov. 1	Feb. 29	
Boston-Lawrence-Salem, MA	Oxygenated	1-Nov-92	30-Jan-96	Nov. 1	Feb. 29	
Chico, CA	Oxygenated	1-Nov-92	31-Mar-98	Oct. 1	Jan. 31	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
Cleveland-Akron-Lorain, OH	Oxygenated	1-Nov-92	4-Feb-94	Nov. 1	Feb. 29	
Colorado Springs, CO	Oxygenated	1-Nov-92	10-Mar-97	Nov. 1	Feb. 29	
Colorado Springs, CO	Oxygenated	10-Mar-97	1-Jun-98	Nov. 1	Feb. 14	
Colorado Springs, CO	Oxygenated	1-Jun-98	22-Dec-00	Nov. 1	Feb. 7	oxygenation made a contingency measure by SIP revision.
Denver-Boulder, CO	Oxygenated	1-Nov-92	10-Mar-97	Nov. 1	Feb. 29	
Denver-Boulder, CO	Oxygenated	10-Mar-97	1-Jun-98	Nov. 1	Feb. 14	Average 3.1% weight oxygen
Denver-Boulder, CO	Oxygenated	1-Jun-98		Nov. 1	Feb. 7	Currently requires ethanol oxygenation
Duluth, MN	Oxygenated	1-Nov-92	14-Apr-94	Oct. 1	Jan. 31	Minnesota currently implements a year-round state program
El Paso, TX	Oxygenated	1-Nov-92	12-Sep-94	Nov. 1	Feb. 29	
El Paso, TX	Oxygenated	12-Sep-94		Oct. 1	Mar. 31	Currently requires ethanol oxygenation
Fairbanks, AK	Oxygenated	1-Nov-92		Nov. 1	Feb. 29	note: Fairbanks program suspended; 10% volume ethanol
Fort Collins-Loveland, CO	Oxygenated	1-Nov-92	10-Mar-97	Nov. 1	Feb. 29	
Fort Collins-Loveland, CO	Oxygenated	10-Mar-97	1-Jun-98	Nov. 1	Feb. 14	
Fort Collins-Loveland, CO	Oxygenated	1-Jun-98		Nov. 1	Feb. 7	Average 3.1% weight oxygen, currently requires ethanol oxygenation
Fresno, CA	Oxygenated	1-Nov-92	31-Mar-98	Oct. 1	Jan. 31	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
Grants Pass, OR	Oxygenated	1-Nov-92		Nov. 1	Feb. 29	
Greensboro-Winston-Salem-High Point, NC	Oxygenated	1-Nov-92	21-Sep-94	Nov. 1	Feb. 29	
Hartford, CT	Oxygenated	1-Nov-92	31-Oct-95	Nov. 1	Feb. 29	
Klamath County, OR	Oxygenated	1-Nov-92		Nov. 1	Feb. 29	Currently requires ethanol oxygenation
Las Vegas, NV	Oxygenated	1-Nov-92	11-Dec-98	Oct. 1	Feb. 29	
Las Vegas, NV	Oxygenated	11-Dec-98		Oct. 1	Mar. 31	3.5% weight oxygen, currently requires ethanol oxygenation
Los Angeles-Anaheim-Riverside, CA	Oxygenated	1-Nov-92		Oct. 1	Feb. 29	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
Medford, OR	Oxygenated	1-Nov-92		Nov. 1	Feb. 29	Currently requires ethanol oxygenation
Memphis, TN	Oxygenated	1-Nov-92	26-Jul-94	Nov. 1	Feb. 29	
Minneapolis-St. Paul, MN	Oxygenated	1-Nov-92	21-Feb-96	Oct. 1	Jan. 31	Minnesota currenly implements a year-round state program
Minnesota	Oxygenated	21-Feb-96		Jan. 1	Dec. 31	State Mandated Program
Missoula, MT	Oxygenated	1-Nov-92		Nov. 1	Feb. 29	
Modesto, CA	Oxygenated	1-Nov-92	31-Mar-98	Oct. 1	Jan. 31	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
New York City, CT	Oxygenated	1-Nov-92	25-Jul-96	Oct. 1	Apr. 30	
New York City, CT	Oxygenated	25-Jul-96	1-Dec-99	Nov. 1	Feb. 29	SIP revisions removed oxygenation as control measure
New York City, NJ	Oxygenated	1-Nov-92	25-Jul-96	Oct. 1	Apr. 30	
New York City, NJ	Oxygenated	25-Jul-96	22-Nov-99	Nov. 1	Feb. 29	SIP revisions removed oxygenation as control measure
New York City, NY	Oxygenated	1-Nov-92	12-Feb-96	Oct. 1	Apr. 30	
New York City, NY	Oxygenated	12-Feb-96	19-Apr-00	Nov. 1	Feb. 29	SIP revisions removed oxygenation as control measure
Ogden, UT	Oxygenated	8-Nov-94	9-Mar-01	Nov. 1	Feb. 29	Oxygenation made a contingency measure by SIP revision.
Philadelphia-Wilmington-Trenton, NJ	Oxygenated	1-Nov-92	30-Jan-96	Nov. 1	Feb. 29	
Philadelphia-Wilmington-Trenton, PA	Oxygenated	1-Nov-92	30-Jan-96	Nov. 1	Feb. 29	
Phoenix, AZ	Oxygenated	1-Nov-92		Oct. 1	Feb. 29	3.5% weight oxygen, currently requires ethanol oxygenation
Portland, OR	Oxygenated	1-Nov-92	2-Sep-97	Nov. 1	Feb. 29	
Portland, OR	Oxygenated	2-Sep-97		Nov. 1	Feb. 29	State Mandated Program
Provo-Orem, UT	Oxygenated	1-Nov-92		Nov. 1	Feb. 29	3.1% weight oxygen content, requested revision to 2.7%, currently requires ethanol oxygenation
Raleigh-Durham, NC	Oxygenated	1-Nov-92	2-Aug-95	Nov. 1	Feb. 29	
Reno, NV	Oxygenated	1-Nov-92		Oct. 1	Jan. 31	Currently requires ethanol oxygenation
Sacramento, CA	Oxygenated	1-Nov-92	31-Mar-98	Oct. 1	Jan. 31	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
Salt Lake City, UT	Oxygenated	8-Nov-94	21-Jan-99	Nov. 1	Feb. 29	
San Diego, CA	Oxygenated	1-Nov-92	31-Mar-98	Nov. 1	Feb. 29	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
San Francisco, CA	Oxygenated	1-Nov-92	31-Mar-98	Oct. 1	Jan. 31	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
Seattle-Tacoma, WA	Oxygenated	1-Nov-92	11-Oct-96	Nov. 1	Feb. 29	Oxygenation made a contingency measure by SIP revision.
Spokane, WA	Oxygenated	1-Nov-92		Sep. 1	Feb. 29	3.5% oxygen, currently requires 100% ethanol
Stockton, CA	Oxygenated	1-Nov-92	31-Mar-98	Oct. 1	Jan. 31	1.8%-2.2% weight oxygen consistent with CARB Phase I, II, III
Syracuse, NY	Oxygenated	1-Nov-92	29-Sep-93	Nov. 1	Feb. 29	
Tuscon, AZ	Oxygenated	1-Jan-96		Oct. 1	Mar. 31	State Mandated Program, 1.8% Weight Oxygen
Vancouver, WA	Oxygenated	1-Nov-92	21-Oct-96	Nov. 1	Feb. 29	
Washington, DC-MD-VA	Oxygenated	1-Nov-92	30-Jan-96	Nov. 1	Feb. 29	
Albany, NY	RFG	1-Jan-95	7-Aug-96	Jan. 1	Dec. 31	Opt-In to Federal RFG, Stay of RFG program granted 1/11/95

Table 1.3: Regional Gasoline Content Regulations*

Area	Content Regulation	Date Effective	Redesignation/ Opt-out Date	Annual Control Period Seasonal Start Date	Seasonal End Date	Area Specific Notes
Allentown-Bethlehem-Easton,NJ	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Atlantic City, NJ	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Baltimore, MD	RFG	1-Jan-95		Jan. 1	Dec. 31	
Boston-Lawrence-Worcester MSA, NH	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Buffalo, NY	RFG	1-Jan-95	7-Aug-96	Jan. 1	Dec. 31	Opt-In to Federal RFG, Stay of RFG program granted 1/11/95
Chicago-Gary-Lake County, IL-IN-WI	RFG	1-Jan-95		Jan. 1	Dec. 31	
Cincinnati-Hamilton, KY	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Dallas-Fort Worth, TX	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Essex, NY	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Hancock & Waldo Co., ME	RFG	1-Jan-95	7-Aug-96	Jan. 1	Dec. 31	Opt-In to Federal RFG, Stay of RFG program granted 1/11/95
Hartford, CT	RFG	1-Jan-95		Jan. 1	Dec. 31	
Houston-Galveston-Brazoria, TX	RFG	1-Jan-95		Jan. 1	Dec. 31	
Jefferson Co., NY	RFG	1-Jan-95	7-Aug-96	Jan. 1	Dec. 31	Opt-In to Federal RFG, Stay of RFG program granted 1/11/95
Kent & Queen Anne's Co., MD	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Knox-Lincoln, ME	RFG	1-Jan-95	10-Mar-99	Jan. 1	Dec. 31	Opt-In to Federal RFG
Lewiston-Auburn, ME	RFG	1-Jan-95	10-Mar-99	Jan. 1	Dec. 31	Opt-In to Federal RFG
Los Angeles-Anaheim-Riverside, CA	RFG	1-Jan-95	1-Mar-96	Jan. 1	Dec. 31	Supplemented by CARB gasoline program beginning 3/1/96
Louisville, KY	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Massachusetts	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Milwaukee-Racine, WI	RFG	1-Jan-95		Jan. 1	Dec. 31	
New York City, NY-NJ-CT	RFG	1-Jan-95		Jan. 1	Dec. 31	
Norfolk, VA	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Philadelphia, PA-NJ-DE-MD	RFG	1-Jan-95		Jan. 1	Dec. 31	
Phoenix, AZ	RFG	10-Jun-98		Jan. 1	Dec. 31	State Mandated Program, Gasoline Must Meet RFG or CARB Phase II standards
Phoenix, AZ	RFG	3-Jul-97	10-Jun-98	Jan. 1	Dec. 31	Opt-In to Federal RFG
Portland, ME	RFG	1-Jan-95	10-Mar-99	Jan. 1	Dec. 31	Opt-In to Federal RFG
Rest of CT	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Rhode Island	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Richmond, VA	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Sacramento, CA	RFG	1-Jun-96	1-Mar-96	Jan. 1	Dec. 31	Supplemented by CARB gasoline program beginning 3/1/96
San Diego, CA	RFG	1-Jan-95	1-Mar-96	Jan. 1	Dec. 31	Supplemented by CARB gasoline program beginning 3/1/96
St. Louis, MO	RFG	1-Jun-99		Jan. 1	Dec. 31	Opt-In to Federal RFG
Sussex Co, DE	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Warren Co, NJ	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Washington, DC	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Washington, MD	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Washington, VA	RFG	1-Jan-95		Jan. 1	Dec. 31	Opt-In to Federal RFG
Western Pennsylvania	RFG	1-Jan-95	7-Aug-96	Jan. 1	Dec. 31	Opt-In to Federal RFG, Stay of RFG program granted 1/11/95
California	RFG/Carb Phase II	1-Mar-96		Jan. 1	Dec. 31	State Mandated Program

* For sake of brevity, this table omits regional low-RVP regulations. For a list of Low-RVP regional regulations updated as of April 2002, see http://www.epa.gov/otaq/volatility.htm.

Chapter 2

Gasoline Price Spikes and Regional Gasoline Content Regulations: A Structural Approach

2.1 Introduction

Much recent interest in gasoline prices has focused on regional gasoline price spikes. These price spikes are limited in geographic scope from the city-level to the size of several states. That is, gasoline prices might rise and then fall dramatically in a particular city or state, while the prices in nearby areas do not change. One such price spike occured in Chicago and Milwaukee in May and June, 2000. From May 30 to June 20, average prices of reformulated gasoline in Chicago and Milwaukee rose from \$1.85 and \$1.74 a gallon to \$2.13 and \$2.02 a gallon. By July 24, gasoline prices dropped to \$1.57 and \$1.48 respectively.[1] In contrast, the national average price for reformulated gasoline during the same period varied less, rising from \$1.64 on May 29, 2000 to \$1.73 on June 19, 2000 and finally dropping back to \$1.66 on July 24, 2000.[2] Similar price spikes can be identified in Figures 2.1 and 2.2. Figure 2.1 shows the monthly average wholesale price for gasoline sold in the Chicago MSA and in California. In

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[1] Final Report of the Federal Trade Commission on the Midwest Price Spikes, March 21, 2001

[2] EIA Motor Gasoline Watch; May 29, 2000; June 19, 2000; July 24, 2000.

addition, Figure 2.1 also plots the price of reformulated gasoline in Texas as well as the most closely tracked domestic spot price for crude oil, West Texas Intermediate (WTI) delivered to Cushing, OK. Figure 2.2 displays the differential between the two gasoline price series and the WTI crude spot price.

In Figure 2.2, price spikes in California and Illinois are apparent. Prior to 1999, wholesale gasoline prices in California and Illinois were, with a few exceptions, ten to thirty cents per gallon more expensive that the WTI crude spot price. Beginning in early 1999, though, wholesale prices in California and Illinois began to increase periodically above this established range. From January 1999 to December 2003, wholesale gasoline prices in Illinois spiked to more than forty cents per gallon above the WTI crude spot price on four occasions, with the largest spike, in Spring 2000, when gasoline prices spiked to over 70 cents per gallon above the WTI crude spot price. Over a similar period, California wholesale gasoline prices spiked over forty cents per gallon above the WTI spot price on nine occasions.

In response to volatile gasoline prices, several academic papers along with research by the FTC, EPA, Senate Subcommittee on Investigations and state commissions qualitatively analyzed structural changes in regional gasoline markets contributing to these spikes.[3] These studies identify three structural changes in the gasoline markets that increase the frequency and magnitude of regional price spikes: (1) inconsistent gasoline content regulations across different geographic regions, (2) declining reserve refining capacity, and (3) industry consolidation within the oil industry. In addition, these studies often identify incident-specific factors, including refinery outages, transportation constraints, reductions in product inventories, or transition costs associated with meeting new environmental regulations.

All studies identify the first factor, regional content regulations, as an important structural change in gasoline markets related to regional price spikes. Over the past ten years, state and local regulations defining local gasoline content have reduced the fungibility of the domestic gasoline supply. In 1990, domestic gasoline met a single

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[3] See for instance, Bulow, Creswell, Fischer and Taylor (2003) and "Gasoline Prices - How Are They Really Set?" (2002)

set of content standards. Ten years later, over fifteen different, and in some cases, mutually exclusive, blends of gasoline are mandated in different geographic areas. A simple model of quantity competition suggests content regulation likely has three distinct effects on gasoline prices. First, blends of gasoline meeting content regulations are more costly to refine than conventional gasoline. Second, additional refining costs associated with state-specific content regulations might influence which geographic regions refiners choose to serve. Finally, incompatible blends of gasoline may reduce the ability of refiners and marketers to move gasoline between geographic regions in response to supply and demand shocks. The first two are persistent effects and would increase average gasoline prices, but would have little effect on price volatility. The third, on the other hand, only affects prices in the event of an unexpected supply or demand shock. The effect of the third, though, depends crucially on the degree of geographic differentiation across regions sharing compatible fuel standards. For example, little gasoline meeting federal reformulated gasoline (RFG) standards is sold in the Midwest. Even if gasoline in Illinois and Milwaukee were compatible with federal RFG, transportation costs from locations producing federal RFG might be sufficient to limit shipments from other RFG producing areas in response to a local shock in the Chicago gasoline market. In this case, transportation cost between geographic markets rather than the product heterogeneity contributes to price spikes resulting from a local shock.

While previous government and academic studies identify factors which contribute to regional price spikes, no study quantifies the effect of the various factors. This paper answers this question by providing a structural method which allows me to distinguish the effect of product heterogeneity due to incompatible content regulations from the effect of geographic differentiation created by transportation costs. In particular, I focus on the effects on price levels and price spikes of the two most stringent regional blends of gasoline, ethanol-blended RFG sold in Chicago and Milwaukee and California Air Resources Board (CARB) gasoline sold throughout California. In addition to analyzing the effect of these regional gasoline content regulations, I simulate counterfactuals controlling for refinery consolidation and declining reserve refining capacity. These simulations estimate the role changes in refinery ownership and the slow growth of refining capacity have on wholesale gasoline prices.

To quantify each of these effects, I specify a structural model of the refining industry based on the production optimization problem faced by individual refineries, allowing for unobservable cost, conduct and elasticity parameters. Although the likelihood function for the structural model cannot be expressed in closed form, I numerically search for values of the unobservable parameters in the model that minimize the squared error between the solution to the optimization problem and actual market-level production. Using values for parameters from the NLLS search algorithm, I then simulate prices of wholesale gasoline in Illinois, Wisconsin and California as if the states sold federal RFG instead of ethanol-blended RFG and CARB gasoline. This approach controls for transportation costs, refinery capacity constraints, changes in refinery ownership and gasoline compatibility. In order to distinguish the effects of content regulations on price levels and price volatility, I build a dataset of unexpected refinery outages. The set of refinery outages allows me to identify months with and without unanticipated local supply shocks and hence months in which local gasoline content regulations affect prices in Illinois, Wisconsin and California through only increased production costs. Comparing simulated prices in months with and without local refinery outages separately identifies the effects of additional production costs of CARB gasoline and ethanol-blended RFG from the effects of incompatibility with federal RFG.

Section 2 discusses the relevant economic literature. Section 3 provides a background on content regulations and the refining industry, focusing in particular on why regulation of gasoline content and refinery outages effect wholesale gasoline prices and the relationship between the effects. Section 4 details the data used and section 5 presents reduced-form estimates of the effect of content regulations on price levels. In section 6, I propose a model of gasoline refining which allows me to estimate the effect of content regulations on regional price spikes and then estimate unobservable parameters of the model in section 7. In Section 8, I specify my primary counterfactual and simulate the effect of the content regulations on regional wholesale gasoline price volatility. In addition, I also simulate alterative counterfactuals and test the robustness of the results to both modelling assumptions and the coefficients of the estimated structural parameters. Section 9 concludes.

2.2 Previous Literature

This paper addresses two aspects of regional gasoline prices: (i) regional price volatility, changes in prices over time and (ii) price dispersion, differences in prices across state or regional markets. Several strands of literature relate to the topic and approach in this paper.

A considerable number of papers study gasoline price adjustment in response to shocks. These studies identify two empirical regularities observed in gasoline markets: prices are sticky, and prices adjust asymmetrically upwards and downwards. Explanations for the former include supply adjustment costs (Borenstein and Shepard, 2000), or menu-cost adjustment (Davis and Hamilton NBER 2003). The literature on asymmetric price adjustment focuses on crude oil price shocks (Borenstein, Cameron and Gilbert, 1997, and Bacon, 1991), but also addresses differences in search costs associated with different petroleum products (Johnson, 2002).

A second strand of literature estimates reduced-form effects of state-level regulatory policies, including divorcement regulation (Vita, 2000), self-service bans (Vandegrift and Bisti, 2001 and Johnson and Romeo, 2000), and sales-below-cost laws (Anderson and Johnson, 1999). These studies exploit cross-state variation in regulation or within-state changes in regulation over time, to estimate the effect of regulations on price levels.

This paper departs from a strictly reduced-form approach used in previous studies in favor of a structural approach like that used in Considine (2001) and Considine and Heo (2002), specifying a structural model based on the production optimization problem faced by individual domestic refineries. These studies incorporate a multi-product optimal production problem of refiners into a structural model, considering refinery production of not only gasoline, but also jet fuel, distillate and other products. Unlike Considine and Considine and Heo, which aggregate individual refiner behavior up to national prices and inventories, this paper optimizes the production decisions for individual refineries choosing quantities of products at the state-product level. I also model the production choice of individual refineries incorporating refinery supply adjustment costs associated with rapid changes in refinery production identified in Borenstein and Shepard (2000). This approach allows me to control for factors that affect regional price levels and volatility, but are difficult to incorporate in a reduced-form approach, including refinery production constraints, changes in refinery ownership, transportation costs and substitutability of different refined products.

In addition to estimating the effect of regulations on price levels and spikes, this paper also identifies the extent to which product heterogeneity and geographic differentiation contribute to product differentiation of wholesale gasoline markets in California, Illinois and Wisconsin. Although different in approach, Pinske, Slade and Brett (2002) assess a similar question. Pinske, Slade and Brett use a semiparametric model to identify the geographic limits of domestic wholesale gasoline markets. While their approach does not rely on industry-specific structural assumptions, the structure I impose on my model allows for the simulation of several counterfactuals.

2.3 Industry Overview

2.3.1 Petroleum Basics

Industry Structure

In this section, I provide background information on the petroleum industry that I use to inform my structural model in Section 6. I first discuss the general technology and spatial organization of the industry and then discuss how the specific industry characteristics contribute to wholesale price volatility spikes.

Production and sale of petroleum products consists several vertically organized steps: (i) Refining of crude oil, (ii) Transportation of refined products by pipeline or barge to regional terminals, (iii) Storage and wholesale sale at regional terminals, (iv)

Transportation by truck to retail stations and (v) Retail sale. The fundamental task of refineries is to heat crude oil in the distillation tower and separate the crude oil into different parts or "streams". The refiner then blends the streams together into end products such as gasoline, jet fuel and diesel.[4] To improve the quality or mix of end products produced, some refiners have additional processing units which alter the chemical properties of the petroleum streams. End products are classified into light products, including gasoline, jet fuel, kerosene and diesel fuel, and heavier products, which include industrial products such as fuel oil and coke. The chemical properties of light products make them more valuable than heavier products, and thus are sold at higher prices. Due to the relative price premium associated with light products, the refiners maximize production of light products subject to capacity constraints of refinery production units. Although refiners maximize light product production, refiners trade off production between light products in response to relative prices. In total, domestic refineries produce the vast majority of domestically-consumed light products, accounting for approximately ninety percent of gasoline, jet fuel and diesel consumption in 2001.[5]

Most domestic refineries are located near crude oil supplies in Texas, Louisiana and California, with over fifty percent of national distillation capacity located in the three states.[6] Remaining domestic refining capacity is sited near specific end markets (e.g. New Jersey and Illinois) or other sources of crude oil (e.g. Wyoming). As

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[4] End-products include everything from propane, gasoline and diesel fuel to industrial fuel oil and residuum for road tar. These products vary along many dimensions, including boiling point, energy content, and octane number. Depending on the use of the end-product, the product must meet criteria along the various dimension. This, in turn, dictates which intermediate streams a refiner can combine to create the product.

[5] Although international imports vary significantly by region, even in the area with the greatest product imports, the East Coast, imports accounted for 22, 21 and 23 percent of gasoline, jet fuel and diesel consumption.

[6] Distillation is the first step in the refining process, where the refinery heats and separates crude oil based on boiling point. As of January 1, 2002, total domestic atmospheric distillation capacity was 17.6 million barrels per day - 25, 16 and 12 percent of this capacity was located in Texas, Louisiana and California respectively.

a result of the geographic concentration of refining assets, the East Coast, upper Midwest and occasionally the West Coast import gasoline from the Gulf Coast to meet regional demand. To supply these markets, refiners ship petroleum products by barge or pipeline to regional wholesale terminals located near most metropolitan areas.

Wholesale terminals serve as a point of sale for industrial and wholesale customers and as a short-term storage point. From the terminal, gasoline is sold to retail stations either at the Dealer Tank Wagon (DTW) price or the Rack price, depending on whether or not the terminal operator provides truck transportation from the terminal to the retail station. Since transportation by truck is substantially more expensive than transportation by barge or pipeline, wholesale terminals are located near most metropolitan areas.

I focus on two crucial aspects of refinery operation which contribute to price volatility and inform my structural model introduced in section 6. First, substantial supply adjustment costs exist due to both specifics of refinery operation and the spatial organization of the industry. Second, refiners must occasionally stop production unexpectedly due to fires, explosions or other accidents. Slow response by unaffected refiners to localized supply outages creates regional price volatility, which regional content criteria exacerbate.

Refinery Operation and Price Volatility

Two aspects of domestic refining affect the speed at which refiners respond to local shocks, (i) supply adjustment costs and (ii) transportation lags between geographic markets. Supply adjustment costs exist since it is costly for a refinery to deviate from a pre-planned production schedule. Supply adjustment costs arise since refiners must contract in advance for crude oil and optimize refinery operation based on the crude properties. Refiners contract for crude oil, several months prior to production, based on the properties of the crude, expected demand for end-products and existing refinery capital. The properties of the chosen crude oil and the processing units at a particular refinery in turn define the set of end-products a particular refinery can produce. Just prior to production, a refiner re-optimizes refinery production based on updated prices and the characteristics of the crude oil.

While refiners can adjust the mix of end-products they produce in the long run, by purchasing different crude oils and changing the operation of the refinery, significant production adjustment costs exist in the short run when the crude oil choice is fixed. Once the production run begins, a refiner must either alter the operation of production units or blend intermediate streams in a different way to achieve a different mix of end-products. A refinery can often only increase the quantity of one high-value end-product, such as gasoline, by blending a greater proportion of high quality intermediate streams.[7] This leaves the refinery with more lower value petroleum streams it either must blend into an end-product, reducing its quality, or sell at a low price on the market. Thus, a refinery incurs significant costs when altering the production mix after a production run begins. In addition, adjustment costs are greatest for end-products meeting the highest specifications, such as gasoline. These products require a refiner to make large changes in blending to continue to meet content requirements for different fuels. As a result of supply adjustment costs, refiners plan production runs several months in advance, beginning when they contract for the crude oil and plan initial refinery operation. During the production runs, which generally last three to six weeks, the refiner generally makes only small changes to the mix of end-products and to the operation of particular units. Since refiners often finish production runs prior to adjusting production mix, supply adjustment costs slow refinery response to supply or demand shocks.[8]

Transportation lags also slow industry response to localized shocks. As mentioned above, domestic refineries are relatively concentrated. Geographic concentration of

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[7] Like refined end-products, the properties of intermediate streams from individual processing units differ significantly. For example, straight run gasoline, extracted directly from the distillation tower, has low octane value (70-75) and high Reid vapor pressure, while alkylate has higher octane (90-95) and lower Reid vapor pressure. In order to produce gasoline meeting RVP limits and minimum octane content, these two streams, along with others, must be blended together.

[8] See Chapter 1 and Borenstein and Shepard (2001) for a discussion of supply adjustment costs in crude oil refining.

refineries implies that areas with excess demand (e.g. Midwest and East Coast) must import petroleum products from areas with excess supply (e.g. Gulf Coast).[9] Figure 2.3 maps the location of large refineries as well as product movements by barge or pipeline between areas. Even if refineries could adjust production immediately in response to shocks, the time to transport gasoline by barge or pipeline also slows the response of the market to a shock. It takes ten to fourteen days to pipe gasoline from the Gulf Coast to Chicago and fourteen to twenty-two days to pipe gasoline from the Gulf Coast to Newark. A similar three week lag exists to barge gasoline from the Gulf Coast to California.

The presence of supply adjustment costs and transportation delays do not necessarily imply a market with regional price spikes. In addition to these two factors, a source of unexpected regional supply or demand shocks must exist and regional inventories must be insufficient to mitigate the supply or demand shocks. Although wholesale terminals do carry inventories, inventories held constitute only two to three weeks of supply. In addition, although inventories exist, operational constraints of storage limit the degree to which storage can mitigate a supply shock caused by a large refinery outage.

2.3.2 Gasoline Content Regulations

An additional industry feature, which increases the effect of refinery outages on domestic gasoline prices, is that gasoline is a differentiated product, due to state-level regulation of gasoline content.[10] In 1990, the Amendments to the Clean Air Act initially mandated federal content criteria for gasoline in regions failing to meet EPA limits for ozone and carbon monoxide pollution. Since mobile-source air pollution depends on both emissions and climate, the 1990 Amendments mandated three broad regional classes of gasoline, conventional, oxygenated and reformulated gasoline (RFG), designing oxygenated gasoline to reduce carbon emissions and RFG to

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[9] Gulf Coast refineries produced roughly 57 and 16 percent of wholesale gasoline consumed in PADD 1 (East Coast) and PADD 2 (Midwest), respectively, in 2001.

[10] See Chapter 1 for a summary of state and federal gasoline content regulations.

limit ground-level ozone pollution. For each of these blends of gasoline, the federal regulations specify standards for two general gasoline characteristics: oxygen content and volatility. Increasing the amount of oxygen in gasoline improves the combustion of gasoline when the weather is cold and reduces carbon monoxide emissions. Decreasing volatility reduces the propensity of gasoline to evaporate and reduces ozone emissions.[11] The EPA requirements mandate minimum standards - subsequent to the federal regulation, many states chose to enact supplementary regulations, either by voluntarily adopting the federal requirements or by mandating more strict regulations.[12] As a result of state-level regulation, fifteen distinct gasoline blends were sold domestically in 2001. Figure 2.4 maps geographic boundaries of federal RFG and oxygenated programs as well as the geographic scope of state and local content regulations supplementing both federal programs.

California, Illinois and Wisconsin impose the most strict supplementary standards for gasoline relative to the standards of federal RFG.[13] Standards for California Air Resource Board (CARB) gasoline limit the proportion of gasoline derived from particular intermediate streams and require gasoline to meet a sulfur cap. RFG sold in Illinois and Wisconsin must meet identical volatility and oxygen content standard to federal RFG, but Illinois and Wisconsin enacted tax incentives such that local refiners meet the oxygen content requirement with ethanol. Ethanol's volatility is high relative to other oxygenates, such as MTBE, and as a result, refiners must create a very low volatility gasoline to blend with ethanol to meet the volatility requirement of federal RFG. Although firms could opt to sell federal RFG in Chicago, they would forfeit tax benefits for MTBE-RFG, as well as for other gasoline mixed with the

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[11] Ground-level ozone increase with temperature, as evaporative emissions increase, and also increases as a function of sunlight. Hence, ozone emissions rise in summer, in warm climates. Alternatively, carbon emissions increase with incomplete combustion associated with starting a cold engine, and are more of a problem in cold climates during the winter.

[12] Opt-in to the federal RFG program accounts for approximately one-third of RFG consumption.

[13] Although the focus of this paper, Illinois, Wisconsin and California are not alone in mandating special blends of gasoline. Currently, 15 different blends of gasoline exist across the country. For an in-depth discussion of "boutique fuels" and the potential effects, Chapter 1.

MTBE-RFG at the wholesale terminal. As a result, gasoline meeting federal RFG requirements is not sold in areas requiring CARB gasoline or ethanol-blended RFG. It is also important to note that not only does federal RFG fail to meet the content specifications of these two blends of gasoline, but CARB gasoline and ethanol-blended RFG are mutually incompatible.

In this paper, I focus specifically on the effects of CARB and ethanol-blended RFG since, unlike oxygenated gasoline, these blends require refinery-level production adjustments to meet content specification. These are in contrast to oxygenated gasoline, which only requires refiners to supplement the oxygen content of conventional gasoline. Increasing production of either CARB gasoline or Ethanol-blended RFG requires a refinery to alter the blending of intermediate streams and potentially entails supplementary processing (eg. the removal of sulfur for CARB gasoline). Thus, these fuels are the ones most likely to entail substantial supply adjustment costs, and the ones most likely to be affected by unexpected supply shocks.

Other Structural Changes

Complicating an analysis of price spikes are structural changes in the industry concurrent with changing content regulations. Substantial industry consolidation occurred during the late 1990's.[14] Although required asset divestitures limited increases in refinery concentration, changes in ownership still may affect competition between refineries. In addition to industry consolidation, there has also been a trend toward decreasing reserve refining capacity over the past twenty years. In 1981, annual refinery production was 68 percent of refinery capacity.[15] Due to closure of old refineries, increasing demand and only incremental changes to refining capacity at existing sites over the past twenty years, current utilization of refining capacity exceeds 95 percent. As a result, unexpected refinery outages could increase local wholesale prices simply

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[14] Large horizontal mergers in the petroleum industry include British Petroleum and Amoco in 1998, Exxon and Mobil in 1999 and BP/Amoco and Arco in 2000.

[15] See Dazzo, N., Lidderdale, T., and N. Masterson, "U.S. Refining Capacity Utilization," Energy Information Administration, Petroleum Supply Monthly

by virtue of little spare production capacity existing in the current industry.

2.3.3 Regional Price Volatility and Refinery Outages

This paper examines the extent to which content regulations in Illinois, Wisconsin and California contribute to gasoline price volatility resulting from unexpected refinery outages.[16] For purposes of the analysis, these supply shocks have two important properties. First, fires and explosions at refineries are unpredictable events. Second, these events are localized supply shocks, and, in many cases, necessitate maintenance of a significant portion of the local refining capacity. An example of such an event is the fire that damaged the Lemont, IL distillation unit on August 14, 2001, closing the refinery for six weeks and reducing production for several months thereafter. While not the largest refinery in Illinois, Lemont accounts for 16 percent of Illinois' distillation capacity. Refinery outages are significantly larger than other types of local shocks in markets, and importantly, are often large relative to local wholesale inventories.

The geographic nature of refining and transportation, local content regulation and supply adjustment costs have the potential to contribute to regional price volatility. In the event of an outage of a plant producing either ethanol-blended reformulated gasoline or California Air Resources Board gasoline, such as the Lemont refinery, incompatible standards prevent nearby refiners producing other gasoline blends from selling them in these areas. In addition to transportation lags and supply adjustment costs, which slow the speed at which refineries respond to shocks, incompatible content regulations might additionally constrain refinery response to supply shocks. Thus, these regulations have the potential to compound the effects of an unexpected refinery outage, especially in the case of gasoline formulations with no substitutes such as ethanol-blended RFG or CARB gasoline.

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[16] Pipeline outages, which are not explicitly modelled in this paper, can act in a similar manner to supply shocks. As an example, a pipeline outage contributed to high gasoline prices in Phoenix, AZ in September 2003.

2.4 Data

I collect two sets of data with which I estimate reduced-form and structural models: (i) market-level prices and quantities, and (ii) refinery-level data influencing production decisions, such as oil prices, transportation costs and refinery outages.

The price and quantity data, from the Energy Information Administration (EIA) Petroleum Marketing Monthly, consist of monthly observations of wholesale price and quantity for the three major light petroleum products, gasoline, No.2 distillate (home heating oil and diesel fuel) and jet fuel. I use seven years of observations, beginning Jan 1995 and ending with Dec 2001, after the Midwest and California price spikes of 2000 and 2001. For gasoline, the EIA separately tracks prices and volumes monthly by state and federal formulation standard.[17] An example observation would be the wholesale price and quantity of federal RFG sold in Massachusetts in August 2000. Since wholesale gasoline prices vary depending on whether or not the wholesaler provides transportation to the retail station, in both the reduced-form regressions and the structural model, I use average monthly "rack" price net of taxes for each state-formulation combination. The "rack" price is the wholesale price paid at the terminal and does not include any transportation costs from the terminal to the individual stations.[18] For diesel and jet fuel, I use regional average monthly prices net of taxes of product sold for resale in each of eight petroleum area defense districts PADDs.[19] Volumes for all products are prime supplier volumes defined as sales by wholesale marketers to retailers. This classification represents the closest analogy to wholesale volumes. To verify that prime supplier volumes are representative of wholesale gaso-

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[17] Ideally, the relevant market for wholesale gasoline would be at the terminal-formulation level. While state-level data does not bias the estimate of persistent effects of content regulation, it would lead to a conservative estimate of the effect of content regulation on price spikes if within-state transportation costs are sufficient to limit arbitrage between terminals within the same state, in the event on a local refinery outage and spike within a particular area.

[18] A shortcoming of the EIA data is that it does not differentiate between branded rack sales (eg. sales of Chevron gasoline) and unbranded rack sales.

[19] Roughly corresponding to the Northeast (1a), Mid-atlantic (1b), South-east (1c), Midwest (2), Gulf Coast (3), Rocky Mountains (4) and West Coast (5).

line volumes, I compare the EIA prime supplier gasoline volumes to state-reported monthly wholesale gasoline sales reported to the Federal Highway Administration.[20]

The EIA Petroleum Marketing Monthly only tracks gasoline sales by federal-formulation standard, and does not specifically track regional blends exceeding federal requirements. Although sales of CARB gasoline or ethanol-blended reformulated gasoline are not identified in the EIA data, both gasoline blends meet federal-RFG standards and are reported as such in the dataset. In addition, no other gasoline blends in California, Illinois and Wisconsin meet federal RFG standards. Thus, I attribute all reported RFG sales in these states as either a sale of CARB gasoline or ethanol-blended RFG depending on the state. For the structural model, I aggregate conventional and oxygenated gasoline, since oxygenated gasoline is only differentiated from conventional gasoline by the addition of oxygenate at the refinery or terminal and does not require incremental refinery-level processing. Therefore, the structural model focuses on six light petroleum products, four of which are distinct blends of gasoline: (i) conventional gasoline, (ii) federal-mandate reformulated gasoline, (iii) ethanol-blended RFG, (iv) CARB gasoline, (v) jet fuel or kerosene, and (vi) diesel fuel or number two distillate fuel. As a result, my panel of market-level data consists of 84 monthly observations for each of 62 markets for gasoline, defined by state and federal formulation standards, eight regional markets for jet fuel and eight regional markets for diesel fuel.[21]

To simulate refinery production, I construct several refinery-specific variables covering (i) ownership and capacity of refineries, (ii) crude oil and transportation costs,

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[20] Although FHA data only report wholesale gasoline sales aggregated across federal formulation standards, I similarly aggregated EIA data for purposes of comparison. Aside from several instances of reporting or recording error in the FHA data, same-state same-month observations from the EIA data and the FHA data were, on average, within three percent of each other.

[21] Sixty two gasoline markets are the result of some states having multiple formulations over the study period. For example, outside of the Milwaukee area, Wisconsin stations sell conventional gasoline. From January 1, 1995 until December 31, 1995, Milwaukee stations sold federal RFG while from January 1, 1996 on, Milwaukee stations sold ethanol-oxygenated RFG. For purposes of this paper, each of these is treated as a separate market for gasoline.

(iii) refinery outage information, and (iv) petroleum product imports. I construct a comprehensive dataset of refinery ownership, closures and capacity over the study period from the EIA Petroleum Supply Annual and annual surveys conducted by the EIA of petroleum capacity at domestic refineries. While the annual surveys include the capacity of various production units at refineries, they do not explicitly define production capacity of gasoline, diesel and jet fuel at these refineries. I use a function of distillation and cracking capacity to calculate the production limit of light products at these refineries, based on crude oil assays which specify the mix of light products derivable from West Texas Intermediate at a simple (distillation only) refinery.[22] Of the 173 domestic refineries operating at some point during the study period, I consider the subset of 117 refineries located in the contiguous US with light product production capacity exceeding eight hundred thousand gallons per day. This subset of refiners contains over ninety-five percent of estimated domestic light product capacity.[23]

Crude oil costs for refineries are monthly average purchase prices of crude oil tracked by the EIA, adjusted for transportation. For refineries located in the Midwest or East Coast, I use the spot price of West Texas Intermediate at Cushing, OK, adjusted for pipeline transportation costs from Cushing to the refinery location. For refineries in Wyoming, Montana and Utah, I use a crude spot price for Wyoming Sour, and for refineries on the West Coast, I use an average spot price for Alaskan North Shore crude and California Offshore crude, all of which I adjust for transportation costs.[24]

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[22] Specifically, my calculation of light-product production capacity at these refineries is equal to forty percent of atmospheric distillation capacity added to the sum of thermal cracking capacity, catalytic cracking capacity and hydrocracking capacity. Although this is a rough measure of capacity, as crude choice affects production limits, individuals knowledgeable about refining consider this a reasonable approximation of light product capacity.

[23] Many smaller refineries produce specialized petroleum products for industrial use and do not actively produce gasoline, jet fuel and distillate. As a result, although these refineries account for approximately five percent of light-product capacity, they account for a smaller proportion of light product production.

[24] Although different spot prices are used, crude spot prices in California, Alaska and Wyoming

Transportation costs for petroleum products by pipelines, barges and trucks are estimates presented before the Federal Trade Commission of 2, 4.5 and 30 cents per gallon per thousand miles of transportation.[25] I identify each refinery's ability to serve each of the 78 markets described above using several sources. Maps of refineries and petroleum product pipelines determine pipeline access of each refinery. In addition, since pipelines are unidirectional, I use these maps to determine the markets each refinery is able to serve by pipeline. Access to barge transportation is determined either by proximity to water or access to pipelines serving water-proximate storage terminals. Transportation costs for each refinery-state combination are then calculated as the least cost method of serving the state from the refinery. For example, a refinery in Texas with access to barges is assumed to serve Nevada markets by barging product from Texas to California and then shipping that product by pipeline from California to Nevada. While I do not explicitly model pipeline constraints in this paper, omitting pipeline constraints would lead to a conservative estimate of the effect of content regulation on price volatility.

Imports of petroleum products are small relative to domestic production - hence, in the structural model, I take imports to be exogenous.[26] The EIA tracks monthly imports by petroleum district of a variety of finished petroleum products, including gasoline by federal-formulation standard. Conventional gasoline imports are assumed to be the sum of oxygenated imports and other gasoline imports. Jet fuel imports are assumed to be sum of jet fuel and aviation gasoline imports. Reformulated gasoline and distillate fuel oil are taken as reported. Since the imports of motor gasoline are reported by PADD and not by state, I proportionately distribute imports to states within each PADD based on same-month consumption of either conventional or reformulated gasoline.

The supply shocks I exploit are unexpected refinery outages due to fires, explo-

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closely correlate with the WTI spot price at Cushing, OK.

[25] See Colonial Pipeline presentation to the FTC. These values are consistent with estimates of transportation costs from the EIA's 2003 California Gasoline Price Study.

[26] Imports of gasoline, jet fuel and diesel fuel were 10, 10 and 9 percent of domestic consumption in 2001.

sions, lightning or other unexpected events at refineries. I identify unexpected outages by searching news, government and industry sources reporting events in the petroleum refining industry. Sources for information on outages include regional and national newspapers, SEC filings made by publicly-traded refiners, and incident reports by the US Chemical Safety Board, EPA and OSHA. I identify a total of 121 incidents, forty-five of which necessitated the shutdown of one or more processing units at the 117 refineries in my subsample from January 1995 to December 2001. For each of these incidents, I identify the processing unit or units involved, the duration of the outage, and estimate the effect of the outage on light-product production. Table 2.1 lists the unexpected outages I identify through news, regulatory and industry sources, along with the outage date, repair date and outage severity.

2.5 Reduced-Form Regression

2.5.1 Data and Estimation

I initially use a reduced-form model to estimate the effect of gasoline content regulations on wholesale price levels. The general specification for the panel regression I use is given by

$$P_{ijt} = f(Q_{ijt}, W_{ijt}, Reg_{ijt})$$

$$Q_{ijt} = g(P_{ijt}, Z_{ijt})$$

where i denotes state, j denotes blend, t denotes time, P_{ijt} is the real rack price of gasoline, Q_{ijt} is the volume of gasoline sold for resale, W_{ijt} is a vector of production input costs, Reg_{ijt} is a vector of content regulation variables and Z_{ijt} is a vector of income and other demographic variables. To consistently estimate the coefficients of the first equation, I use the vector of demand factors exogenous to price, Z_{ijt}, to instrument for quantity in the first equation. Table 2.2 lists descriptive statistics for the variables used in the reduced-form model. This approach implicitly treats content regulation as exogenous to price. Regulation is exogenous to price for areas required to adopt either RFG or oxygenated gasoline due to non-compliance with Clean Air

Act standards. For areas opting into the federal programs, if a state decision is endogenous to gasoline price, states for which content regulations are more costly would be less likely to opt-in. Thus, treating regulation as purely exogenous provides a conservative estimate of the mean price effect.

In order to estimate coefficients for content regulation, consider the fixed-effects panel regression corrected for AR(1) errors

$$P_{ijt} = \alpha + \beta_0 Q^Z_{ijt} + \beta_1 WTI_t + \gamma Reg_{ijt} + \nu_i + \phi_{ijt}$$

$$\phi_{ijt} = \epsilon_{ijt} + \rho\epsilon_{ijt-1}$$

$$\epsilon_{ijt} \sim N(0, \sigma^2_{ij})$$

where ν_i denote state fixed-effects, Q^Z_{ijt} instrumented quantity, WTI_{ijt} West Texas Intermediate crude oil spot price delivered to Cushing, OK, instrumented by the Brent North Sea crude spot price, and Reg_{ijt} content regulation dummy variables identifying blends meeting oxygenated gasoline, RFG, ethanol-blended RFG and CARB gasoline requirements.[27] In subsequent specifications, I also include month-year fixed effects and month-region fixed effects. In each of these specifications, states entering and leaving the programs and states with more than one specification of gasoline identify of the effect of regional content regulations. Table 2.3 presents the coefficients and standard errors for three model specifications. Errors are assumed to follow an AR(1) process within state-blend panels with a common autocorrelation coefficient ρ, and are heteroscedastic across state-blend pairs.

I also run fixed-effects regressions for several alternative specifications. Specification 2 uses WTI crude spot price with a vector of month-year fixed effects, and specification 3 allows for month fixed effects which vary by PADD. The second specification allows for a more flexible common time-trend than the specification including WTI crude spot price. The third specification allows for different monthly trends for each region. In each regression, ethanol-blended RFG and CARB gasoline dummy

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[27] A Hausman specification test of the random effects model indicates that $E[\epsilon, \nu] \neq 0$, necessitating the use of a fixed-effects specification.

variables are additive with respect to the RFG dummy. Thus, the coefficients for either the ethanol-blended RFG or CARB dummies represent the effect on price levels from more strict regulation, relative to federal reformulated gasoline.

Looking at the first specification, the coefficients on content regulation dummies are positive and sign-consistent with ex-ante predictions of increased production costs of CARB gasoline, RFG and oxygenated gasoline relative to conventional gasoline. The coefficients of the content regulations dummies are statistically significant at the one percent level. Relative to conventional gasoline over 1995 to 2001, oxygenated gasoline and reformulated gasoline rack prices are 3.5 and 3.8 cents per gallon higher than conventional gasoline. In addition, ethanol-blended RFG and CARB gasoline rack prices are 1.8 and 3.2 cents per gallon higher than federal RFG, although each point estimate is imprecisely estimated.[28] Allowing for state-specific monthly trends in specification 3, the estimated price effect of the regulations are 4.9 cpg and 4.2 cpg for oxygenated gasoline and federal RFG relative to conventional gasoline, and 1.7 cpg and 5.1 cpg for ethanol-blended RFG and CARB gasoline relative to federal RFG. These estimates are consistent both with EPA estimates of the incremental cost of federal RFG over conventional gasoline of four to eight cents per gallon, historical Chicago/Dallas RFG price differentials of six to eleven cents per gallon, and California Air Resource Board estimates of incremental costs of CARB gasoline standards of five to fifteen cents per gallon.[29]

2.5.2 Structural Model Justification

The reduced-form model provides a consistent estimate of the effect on wholesale price levels of federal and regional gasoline content regulations. In order to iden-

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[28] It is important to note that oxygenated and reformulated gasoline also have lower energy content than conventional gasoline due to the addition of oxygenates. These blends reduce mileage per gallon in cars by 2-3 and 1-2 percent respectively. This effect is not incorporated into these regression, but would increase the price level effect of these regulations.

[29] See Testimony of R. Perciasepe and Testimony of C. Browner before US House of Representatives, Commerce Committee, July 2000 (http://www.epa.gov/ocir/hearings/testimony/) and Bulow et al. at page 146

tify the effect of content regulations on regional price spikes, though, I formulate a structural model of refinery production decisions. The structural model allows me to simulate counterfactuals in which California, Illinois and Wisconsin mandate gasoline blends meeting only federal RFG requirements. Such a counterfactual is difficult to formulate in the reduced-form model. A counterfactual in which California gasoline meeting only federal-RFG standards must control for transportation costs from other sources of federal-RFG. If transportation costs are sufficiently high, compatibility with federal-RFG standard may not mitigate the effect of an unexpected refinery outage. A structural model allows me to control for this, by simulating the production decisions of refiners which incorporate transportation costs and changes in refinery ownership.

2.6 Structural Model of Supply Shocks

To simulate an accurate counterfactual, I specify a structural model based on the production optimization problem of refineries, which allows me to identify the effect of incompatible regulations coming from production costs, changes in competition due to incremental production costs and changes in the response of refineries to unexpected outages.

I consider a three step game in which refiners choose quantities of light petroleum products to maximize an objective function subject to changing information about refinery outages. Consistent with refinery planning prior to production runs, refineries make production decisions in the first step without knowing outages. Outages are then realized and observed by refineries. Finally, since refineries can reallocate production, but supply adjustment costs exist, refineries re-optimize production in the final step in response to the outage, under the constraint that the product mix chosen in the first step is unchanged. Thus, a refinery choosing to produce federal RFG, but not CARB gasoline, can redistribute federal RFG from one market to another in response to an outage, but cannot, in the short term, produce CARB gasoline instead.

In the first step, I assume that refineries have knowledge of all supply and demand variables with the exception of unexpected outages occurring in the current period. That is, prior to choosing initial production at time t, refineries know the inverse residual demand curve accounting for imports, $p_{jt}(.)$, in each geographic and product market $j \in \{1, 2, \ldots, J\}$ in addition to input costs for all refineries. For each domestic refinery, $i \in \{1, 2, \ldots, I\}$, let q_{ijt} be the initial choice of quantity in market j at time t, $\overline{q}_{it}$ denote the total production capacity of all light petroleum products, $c(q_{i1}, q_{i2}, \ldots, q_{iJ})$ be the refinery production cost function and t_{ij} denote the transportation costs from refinery i to market j.

In the second step, refinery outages and severity are realized and fully observed by all refineries.

In the third step, refiners re-optimize their production decisions in response to the realization of outages $\omega \in \Omega$. Refineries are allowed redistribute their production from step 1 across geographic markets, but not across petroleum products. Thus, I denote $\{J_1, J_2, \ldots, J_n\}$ a proper partition of markets $\{1, 2, \ldots, J\}$, where all markets sharing a given set of content regulations belong to one element of $\{J_1, J_2, \ldots, J_n\}$.[30] Given a partition of the markets based on product characteristics, in the third step, a refiner owning a set of refineries $\tilde{I} \subset \{1, 2, \ldots, I\}$ chooses a vector of Nash quantities $\{\tilde{q}_{ijt}\}$ for $i \in \tilde{I}$ to maximize an objective function consisting of own-refinery profits plus a portion of non-own refinery profits, captured by the coefficient of competition, α.[31] That is, the objective function of a particular refiner is given by

$$U = \sum_{i \in \tilde{I}} \Pi_{it} + \alpha \sum_{i' \notin \tilde{I}} \Pi_{i't}$$

where Π_{it} is given by

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[30] For example, J_1 could denote conventional gasoline markets, J_2 reformulated gasoline markets, J_3 jet fuel markets, and J_4 CARB gasoline.

[31] See Cyert and DeGroot (1973). In this formulation, the interpretation of α is the weight an individual refiner places on the profits of refineries it does not own. A value of $\alpha = 1$ is consistent with joint profit maximization by all refiners while a value of $\alpha = 0$ implies entirely own-profit maximization.

$$\Pi_{it} = \sum_j \tilde{q}_{ijt}(p_j(.)) - \sum_j \tilde{q}_{ijt}t_{ij} - c(\tilde{q}_{i1t}, \tilde{q}_{i2t}, \ldots, \tilde{q}_{iJt}).$$

subject to non-negativity constraints and binding product-level capacity constraints

$$\begin{aligned} \tilde{q}_{ij} &\geq 0 \text{ for all j} \in \text{J} \\ \sum_{j \in J_1} \tilde{q}_{ij} &= \sum_{j \in J_1} q_{ij} \\ \sum_{j \in J_2} \tilde{q}_{ij} &= \sum_{j \in J_2} q_{ij} \\ &\ldots \\ \sum_{j \in J_n} \tilde{q}_{ij} &= \sum_{j \in J_n} q_{ij} \end{aligned}$$

Note that in this specification, a value of $\alpha = 1$ implies joint profit maximization by all refineries and $\alpha = 0$ implies a single-period game in quantities. For refineries affected by an outage at time t and with initial production exceeding post-outage refinery capacity, production is scaled back evenly across all products.

Prior to the realization of outages, the refinery chooses a binding production mix, which it is then able to allocate in response to outages. Once the refinery commits to a production mix in the first step of the optimization, it is constrained to that mix after the realization of outages, consistent with substantial industry supply adjustment costs within, but not between, production runs. Thus, in the first step, refiners choose pre-planned production quantities of each petroleum product to maximize the expectation, with respect to all possible refinery outages $\omega \in \Omega$, of own-refinery profits plus a portion of other refinery profits, α. The objective function for a refiner owning refineries $\tilde{I} \subset \{1, 2, \ldots, I\}$ is given by

$$U = E(\sum_{i \in \tilde{I}} \Pi_{it}) + \alpha E(\sum_{i' \notin \tilde{I}} \Pi_{i't}),$$

subject to refinery capacity and non-negativity constraints

$$\begin{aligned} q_{i1} + q_{i2} + \ldots + q_{iJ} &\leq \overline{q}_i \\ q_{ij} &\geq 0 \end{aligned}$$

for all $i \in \tilde{I}$ and all j where Π_{it} is again

$$\Pi_{it} = \sum_j \tilde{q}_{ijt}(p_j(.)) - \sum_j \tilde{q}_{ijt}t_{ij} - c(\tilde{q}_{i1t}, \tilde{q}_{i2t}, \ldots, \tilde{q}_{iJt}).$$

In the first step, the expectation is taken with respect to the continuous state space of all possible refinery outages. In order to numerically solve for the equilibrium, I initially assume refiners place a zero prior probability on unexpected refinery outages.

Treating the optimization in this way induces refineries to produce less CARB and ethanol-blended RFG than they otherwise would if they assumed an outage at a plant in California or Illinois were likely. As part of my sensitivity analyses, I verify the robustness of my simulations to this assumption by allowing for refineries to place a positive prior probability on a discrete subspace of the continuum of all possible refinery outages. I find that this assumption does not change my conclusions. Although outages have a large local effect, the probability of an outage is low.[32] When choosing production, refiners weigh the benefits of additional CARB or ethanol-RFG production in states of the world in which a local outage occurs in California, Illinois or Wisconsin, against the incremental production costs associated with manufacturing CARB or ethanol-RFG as well as the shadow-cost of capacity if the refinery is capacity constrained. As a result, assuming refiners place a zero probability prior on unexpected outages does not change refinery choice of production significantly. When simulated, the magnitude of the effect is over an order of magnitude less than the effect of the content regulations.

Given the specification of the game above and suppressing the time subscript, initial choice of production for market j by refinery i satisfies the first order condition

$$q_{ij}\frac{\partial p_j}{\partial q_{ij}} + \sum_{k \in \tilde{I}/i} q_{kj}\frac{\partial p_j}{\partial q_{ij}} + \alpha \sum_{k \notin \tilde{I}} q_{kj}\frac{\partial p_j}{\partial q_{ij}} + p_j - t_{ij} - \frac{\partial c_i}{\partial q_{ij}} + \lambda_i + \mu_{ij} = 0$$

where λ_i denotes the shadow cost of production capacity at refinery i and μ_{ij} denotes the non-negativity constraint. In the event of an refinery outage, the final choice of

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[32] Recall that over the seven year period, news, industry and government sources document only forty-five production-lowering outages. Over the seven year period, the expected monthly percentage of total refinery capacity down due to an unexpected outage is 0.2 percent.

production satisfies

$$q_{ij}\frac{\partial p_j}{\partial q_{ij}} + \sum_{k \in \tilde{I}/i} q_{kj}\frac{\partial p_j}{\partial q_{ij}} + \alpha \sum_{k \notin \tilde{I}} q_{kj}\frac{\partial p_j}{\partial q_{ij}} + p_j - t_{ij} - \frac{\partial c_i}{\partial q_{ij}} + \hat{\lambda}_{ij} + \mu_{ij} = 0,$$

where $\hat{\lambda}_{ij}$ denotes the shadow cost of the production constraint of refinery i to increase production of a petroleum product compatible with product j. Alternatively, expressing the FOC as a lerner-style index, the quantities of all I refineries must jointly satisfy the set of I first order conditions for market j, given by

$$\frac{p_j - t_{ij} - \frac{\partial c_i}{\partial q_{ij}} + \lambda_i + \mu_{ij}}{p_j} = \frac{1}{\epsilon_{ij}} + \sum_{k \in \tilde{I}/i} \frac{1}{\epsilon_{kj}} + \alpha \sum_{k \notin \tilde{I}} \frac{1}{\epsilon_{kj}},$$

where ϵ_{ij} denotes elasticity of the residual demand curve faced by refinery i in market j at quantity q_{ij}.

To complete the model, I make functional form assumptions for the cost and demand functions, $c(q_{i1}, q_{i2}, \ldots, q_{iJ})$ and $p_{jt}(.)$. Let the refinery production cost function be additively separable and let the marginal cost of refinery i to produce a fuel for market j at time t be

$$\begin{aligned} MC_{ijt} &= \beta_0 + \beta_1 * OilPrice_{it} + \beta_2 * Log(DC_{it}) + \\ &\quad \beta_3 * RFG_j + \beta_4 * ERFG_j + \beta_5 * CARB_j + \beta_6 * JF_j + \beta_7 * DIST_j \end{aligned}$$

where $OilPrice_{it}$ is the delivered oil price at refinery i, $Log(DC_{it})$ is the log of atmospheric distillation capacity of refinery i, and RFG_j, $ERFG_j$,$CARB_j$, JF_j and $DIST_j$ are dummy variables corresponding to reformulated gasoline, ethanol-blended RFG, CARB gasoline, jet fuel and distillate.[33] This choice of functional form for the cost function captures both the differential production costs for various products, as well as economies of scale in refinery production, as the coefficient on the log of distillation capacity. Moreover, it allows for region-specific crude prices, incorporating both the price of local crude streams and transportation to the refinery.

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[33] Although other products exist, including residuum, residual oil and other light products, gasoline, distillate and jet fuel constitute the vast majority of light products produced at refineries. In addition, the properties of each are similar enough that similar intermediate streams are used for each.

I take $p_{jt}(.)$, the inverse demand function for market j at time t, to be linear given by the functional form

$$p_{jt}(q_{jt}) = p^A_{jt} + (\frac{-p^A_{jt}}{\epsilon q^A_{jt}})(q_{jt} - q^A_{jt}).$$

where p^A_{jt} and q^A_{jt} are the observed price and quantity in market j at time t. This specification is equivalent to a first-order taylor approximation of a isoelastic demand curve, $q_{jt}(p_{jt}) = \frac{\gamma}{\epsilon}p^{\epsilon}_{jt}$, taken at the observed price and quantity in market j at time t.

2.7 Structural Estimation

2.7.1 Assumptions and Estimation

Absent the functional form specifications for the cost and demand functions, the three-step model in the previous section defines a deterministic correspondence, which I denote $f : (X, \theta) \rightarrow Y$, between factors influencing refinery supply decisions, such as content regulations, input and transportation costs collectively denoted (X), and the vector of unobserved parameters (θ), which includes unobserved cost, conduct and elasticity parameters, and market-level prices and quantities (Y).[34] That is, f maps a given state space and values for unobservable parameters to all market equilibria that are solutions to the refinery optimization problem. Given the linear functional forms assumed for supply and demand, the set of FOCs for the model simplifies to a full-rank linear problem. Thus, the functional form assumptions provide a sufficient condition for f to be a function, implying a unique solution to the optimization problem.

Since the model contains unobservable parameters for refinery conduct and production cost, prior to simulating the effect of the content regulations, I first estimate the vector of unobservable cost, conduct and elasticity parameters, θ. In order to estimate the unobserved parameters, I introduce a stochastic error term into the demand curve of each market, that is common to all refiners, and realized after refiners

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[34] The set of unobservables, denoted θ, consists of the eight cost parameters $\{\beta_1, \beta_2, \ldots, \beta_8\}$, the conduct parameter α and demand elasticity parameter ϵ.

choose quantities in each market. I take $\delta_{jt} \sim N(0, \sigma^2)$ to be an additive stochastic shock to the inverse demand curve for market j from the previous section,

$$p_{jt}(q) = p_{jt}^A + (\frac{-p_{jt}^A}{\epsilon q_{jt}^A})(q_{jt} - q_{jt}^A) + \delta_{jt}.$$

I assume that δ_{jt} is independent and identically distributed across geographic areas. Intuitively, this source of error is akin to a common market shock to a population's propensity to drive, unobservable to refiners. For example, unexpectedly good or poor weather might constitute a shock to demand, common yet unpredictable to all refiners serving a particular market. Linearity of the refiner FOC's implies a structural functional form given by the non-linear regression

$$Y_{jt} = f(X_t, \theta) + \delta_{jt}, \delta_{jt} \sim N(0, \sigma^2).$$

Due to the three-step nature of the model, the associated likelihood function cannot be expressed as a closed function of the vector of unobserved parameters.

Thus, I numerically search for the NLLS set of parameters, that is, $\hat{\theta} = argmin_\theta((f(X,\theta) - Y)'(f(X,\theta) - Y))$. I estimate $\hat{\theta}$ numerically, finding the vector of values for θ minimizing the squared error between $f(X, \theta)$ and Y via a steepest ascent search algorithm.[35] As part of my robustness checks, I test the sensitivity of my simulation results to variations in the NLLS parameter point estimates.

2.7.2 Estimated Parameters and Interpretation

Table 2.4 lists the NLLS estimates for $\hat{\theta}$. The point estimates are generally consistent with expectations. The coefficient on log distillation capacity, β_1, is less than 0 and consistent with increasing returns to distillation capacity. The coefficient on crude cost, β_2 is below the ex ante prediction of 1. This suggests that the spot

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[35] In this case, the steepest ascent search algorithm is computationally efficient relative to a method requiring computation of the second derivatives, such as Gauss-Newton. The seed point for the steepest ascent algorithm, $\alpha = .15, \beta_0 = 5, \beta_1 = 1, \beta_2 = -1, \beta_3 = 5, \beta_4 = 8, \beta_5 = 10, \beta_6 = -2, \beta_7 = -4$, is based on an initial simulation of PADD 5 only and ex-ante government estimates for production costs of different gasoline blends.

price overstates the price of crude oil processed at refineries, possibly due to long term contracts whose prices vary less than domestic spot prices. Cost parameters corresponding to differential production costs for different product blends are similar to government and industry estimates. The incremental production costs for federal RFG and CARB gasoline are within EPA and CARB estimates of four to eight cents and five to fifteen cents respectively.

The competition coefficient and elasticity estimates are similar to expectations as well. Although it is possible to reject the null hypothesis that the coefficient of competition is 0, the estimated value of α is 0.03, consistent with almost complete own-profit maximization by refiners. Repeated interaction could enable tacit collusion amongst refiners - in such a world, tacit collusion would reduce production below the levels which maximize own-refiner profit in the static game. In other words, refiners place positive weight on the profits of other refiners. The small point estimate for α suggests persistent tacit collusion is not prevalent, consistent with the conclusions of academic and non-academic studies.[36]

The estimate of short-run gasoline demand elasticity is consistent with both the meta-analysis presented in Espey(1998) and recent estimates in Considine (2001). Espey finds the mean and median of 363 estimates of short run gasoline demand to be -0.26 and -0.23, respectively. My estimate of the short run elasticity, -0.337, is slightly more elastic than the median and mean of the sample collected in Espey, but is well within the range of sample estimates of 0 to -1.36.[37] In addition to other robustness checks, I verify my conclusions are unchanged by using a demand elasticity of -0.23.

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[36] See, in particular, Bulow et al. (2003) and FTC Midwest Price Spike Investigation (2001). This approach, though, cannot rule out infrequent collusion by refiners.

[37] As part of my robustness checks, I perform specific sensitivity tests to verify that my simulations estimates are robust to the assumption of more inelastic demand.

2.7.3 Model Fit

As important as reasonable estimates of the parameters is the degree to which the structural model accurately simulates prices across the different product and geographic markets. It is also important that the model predict price spikes resulting from unexpected refinery outages. I use two metrics to measure the fit of the simulated and actual prices. By product and geographic market, I compare the first and second moments of the simulated and actual prices, to assess whether, in aggregate, the simulation accurately models factors which lead to differences in wholesale prices across products and geographic markets. Table 2.5 and 2.6 list descriptive statistics for actual and estimated prices across different petroleum products and different PADD regions. For comparison, I include the estimated price from both the structural model and the reduced-form model. The reduced-form and structural models draw from identical samples, with the exception that the reduced-form model does not estimate prices for jet fuel and diesel.

Both the mean and standard deviations for the simulated wholesale prices are similar across blends and regions to mean and standard deviations of actual prices. Across geographic regions, all estimates from the structural and reduced-form models are within four percent of the actual means. The structural model overpredicts mean product price in PADD 3 (Gulf Coast) and PADD 1a (New England) by 2.8 cpg and 1.6 cpg, and underpredicts prices in PADD 4 (Rocky Mountains) and PADD 1b (Mid-Atlantic) by 1.5 and 1.2 cpg. Mean estimates for the PADD 2 (Midwest) and PADD 5 (West Coast) are within 0.5 cpg of the actual means. Mean prices, by formulation, estimated by the structural and reduced-form models are near actual estimates as well. The largest over- or under-estimation of mean price is that of CARB gasoline, overestimated by six percent.

Maximum simulated prices are lower than the maximum actual wholesale prices from 1995 through 2001. The largest deviation exists for ethanol-blended RFG where the difference between estimated and actual maximum prices is 30 and 27 cpg for the structural and reduced-form models, respectively. The underestimation is the result of the simulation not fully predicting the Spring 2000 price spike for ethanol-blended RFG. While several refinery outages occurred in Spring 2000, these do not sufficiently explain the large change in the price ethanol-blended RFG.[38] During this period , ethanol-blended RFG was first required to meet more strict federal Phase II guidelines. Initially, refiners had difficult meeting Phase II emission guidelines while continuing to use ethanol as an oxygenate. This transition contributed to high prices of ethanol-blended RFG in Spring 2000, and as an initial but not persistent difficulty with producing ethanol-blended RFG is not accounted for by the simulation model. Hence, simulated prices are substantially below actual prices for ethanol-blended RFG during May 2000.

To assess the degree to which the model accurately captures the effect of outages, I first-difference the simulated and actual wholesale prices in months with unexpected local outages. Although the model does not predict the Spring 2000 price spike in the Midwest, the model does predict wholesale price responses to local outages well. The simulated mean change in wholesale ethanol-blended RFG prices in months with a local unexpected outage is 9.91 and 9.90 cents per gallon in Illinois and Wisconsin, which is close to the actual mean change of 10.08 and 9.71 cents per gallon respectively. For CARB gasoline, simulated mean change in wholesale prices in months with unexpected outages of California refineries is 5.91 cents per gallon, relative to an actual mean change of 6.65 cents per gallon.

2.8 Simulation Results

Using the NLLS estimates of the cost, conduct and elasticity parameters, I simulate wholesale prices under several counterfactuals to estimate the degree to which content regulations, industry consolidation and declining reserve capacity affect price levels and price spikes. I also test the sensitivity of the simulation results to variations in the NLLS estimated parameters and modelling assumptions.

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[38] Contributing factors to the Spring 2000 price spike are qualitatively discussed in Bulow et al (2003) and FTC (2001).

2.8.1 Effects of Gasoline Content Regulation

I estimate the effect of CARB gasoline and ethanol-blended RFG on regional price levels and the extent to these local content regulations contribute to price spikes caused by refinery outages. To quantify the effect of these regulations, I simulate counterfactual prices for each of my 78 markets as if the content regulations in California, Illinois and Wisconsin simply met federal RFG standards. For the counterfactual, I keep all outages, changes in ownership, capacity additions, and input costs identical to those in the base case. Thus, the only difference between the base case and initial counterfactuals is the change in gasoline content regulation in the three states.

Treating gasoline standards in California, Illinois and Wisconsin as compatible with federal RFG standards has three effects. First, production costs for federal RFG are lower than those for either CARB gasoline or ethanol-blended RFG. A second related effect is that if production costs change, refineries make different production choices under non-outage conditions. Finally, in the event of a local refinery outages, regional standards prevent reallocation of output across geographic markets, which would occur but for incompatible content regulations. NLLS estimates for cost parameters identify the first effect, the incremental production costs associated with CARB or ethanol-blended RFG. I distinguish the second and third effects by identifying months in which unexpected local refinery outages occurred in California, Illinois and Wisconsin. For months without outages, the first two effects alter prices while for months with unexpected outages, all three have an effect on the market price.[39] Thus, the average price differential between the base case and counterfactual in months without local outages identify the persistent effects of additional production costs. The difference in the average price differential in months with local outages and months without outages identify the effect of incompatible content regulations. For outages exceeding a month in duration, I only consider the first month of the outage, since refiners subsequently adjust production mix after the first month to account for the outage.

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[39] Note this makes an implicit assumption, supported both by the simulation results and actual data, that local refinery produce the vast majority of CARB gasoline or ethanol-blended RFG.

I calculate the average differential between the simulated price in the base case, with existing content regulations in CA, IL and WI, and the simulated price in the counterfactual, where regulations in CA, IL and WI are compatible with federal-RFG. In particular, I calculate the average differential conditional on whether or not an unexpected local outage occurred, as well as unconditional on outage. I list the average price differentials in Table 2.10. The differential in months without outages (column 3 in Table 2.10) identifies the persistent effect of increased production costs. The average price differential in months with local outages (column 1) identifies the effects of both increased production costs and content regulations incompatible with federal RFG criteria.

The point estimates of price effects of additional production costs associated with content regulations in California, Chicago and Milwaukee are 4.5, 3.0 and 2.9 cents per gallon. That is, conditional on outage-free operation of all domestic refineries, average wholesale price in California, Chicago and Milwaukee would be 4.5, 3.0 and 2.9 cents per gallon lower if areas required federal RFG instead of CARB and ethanol-blended RFG respectively. Conditional on a local outage in California, Illinois and Wisconsin, content regulations inconsistent with federal RFG standards raise wholesale gasoline prices in California, Chicago and Milwaukee 9.3, 9.6 and 9.9 cents on average.[40] Since months with local outages provide a point estimate of the combined effect of increased production costs and incompatible regulations, removing the portion of the price changes attributable to additional production costs provides an estimate of the portion of the price spikes attributable solely to incompatible fuel regulations. Taking the difference between the differential contingent on a local outage and the differential contingent on outage-free operation (ie. the difference between Column 1 and Column 3 in Table 2.10), I find that incompatible content regulations raise prices 4.8, 6.6 and 7.0 cents per gallon in California, Illinois and Wisconsin.

Since actual refinery outages vary in severity and duration, the larger effect of fuel

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[40] Substantial variation exists across specific local outages - in months with the largest outages in California, Illinois and Wisconsin, simulated prices with local content regulations are 20 cents per gallon higher than simulated prices in the counterfactual.

incompatibility in Chicago and Milwaukee could be simply a result of the magnitude of local refinery outages experienced in Illinois and Wisconsin. That is, if refinery outages in Illinois and Wisconsin were of greater magnitude or of longer duration than outages in California, the effect of content regulations would appear greater due entirely to differences in local outages. As a way to control for the severity and duration of local shocks, I simulate market prices under another counterfactual, in which local content regulations exist but no refinery outages occur. Comparing simulated prices in this counterfactual to those in the base case provides an estimate of the magnitude of the outages in California, Illinois and Wisconsin. For example, to estimate the effect of local refinery outages on California, I simulate gasoline prices in California without outages and compare simulated prices with the simulated prices from the base case (which include the outages). I then calculated the average differential between the two across all periods in which an unexpected outage occurred at a California refinery. Table 2.9 lists estimates equivalent to those in Table 2.10, with the exception that the counterfactual removes all outages as opposed to changing fuel compatibility. The value in the upper left corner of Table 2.9 is the average price differential in California between months in which a local outage occurred and those same months but-for the outage. The point estimates for the effect of local refinery outages are 6.7, 7.3 and 7.7 cents per gallon for California, Chicago and Milwaukee respectively. This suggests that indeed, local refinery outages in Illinois and Wisconsin over 1995 to 2001 were of greater magnitude than local outages in California.

The estimates in Table 2.9 provide a way to normalize the estimates of the effect of fuel compatibility across states. Using the calculated magnitude of local outages in California, Illinois and Wisconsin, I normalize the effect of incompatible content regulations from Table 2.10 by the magnitude of the outage in Table 2.9. Calculating the ratio of the effect of fuel incompatibility to the effect of the refinery outages gives an estimate of the proportion of the effect of local outages which could be mitigated if local content regulations met less stringent federal RFG standards. The proportion mitigated by compatibility with federal RFG in California, Illinois and Wisconsin is 72, 91 and 92 percent respectively. That is, in California, of the 6.7 cent per gallon average simulated increase in price due to local outages, 4.8 cents of the increase (72 percent) would be avoided if CARB regulations were compatible with federal-RFG standards. Thus, although refinery outages were of greater magnitude in Chicago and Milwaukee than in California, fuel compatibility still has a larger effect on prices contingent on a local refinery outage, even after controlling for outage magnitude. Regardless, these results imply that price volatility from local refinery outages could be substantially mitigated by content regulation compatible with federal RFG standards, especially in the case of Illinois and Wisconsin.

The greater degree to which gasoline compatibility mitigates price spikes in Chicago and Milwaukee is consistent with product differentiation arising from both product heterogeneity(ie. different content regulations) and geographic differentiation(ie. transportation costs). Conceptually, the counterfactual simulates prices in California, Illinois and Wisconsin removing product heterogeneity, but not geographic differentiation. Whether compatibility mitigates the effect of supply shocks depends on the extent to which California, Illinois and Wisconsin are geographically differentiated from refineries producing federal RFG. Fuel compatibility only mitigates a supply shocks if transportation costs from refiners producing RFG in other regions are sufficiently low. If gasoline sold in Chicago and Milwaukee met federal RFG standards, Gulf Coast refineries producing federal RFG for the East Coast could shift shipments to Chicago and Milwaukee via low cost pipelines in response to a refinery outage in Illinois. In contrast, these refineries, also the lowest cost non-local source of RFG for California, ship by barge to California, incurring higher transportation costs. The price differential between California and Texas must be greater to induce the same amount of reallocation of RFG in response to a supply shock. Thus, higher transporation costs imply less mitigation of an outage-based price spike of similar magnitude. This result indicates that virtually all of the product differentiation for Chicago and Milwaukee ethanol-blended RFG is due to product heterogeneity. In constrast, both product heterogeneity and geographic differentiation contribute to price spikes in California.

2.8.2 Additional Counterfactuals

In addition to simulating the effect of incompatible content regulations, I also simulate two other counterfactuals. First, I estimate the effect of changes in refinery ownership over the 1995-2001 period on wholesale gasoline prices. Second, I simulate a counterfactual in which I increase the production capacity of all refineries, to estimate the effect of declining reserve refining capacity.

Changes in Refinery Concentration

To simulate the effect of changes in refinery ownership, I simulate prices, holding refinery ownership from January 1995 constant throughout the period. That is, I simulate prices as if no changes in refinery ownership occurred. All refinery retirements or capacity additions are kept identical to those actually observed. I first calculate the average simulated prices under the counterfactual by PADD region (Table 2.7) and product formulation (Table 2.8). Comparing the simulated prices for the counterfactual to the simulated prices for the base case estimates the effect of refinery consolidation on wholesale prices. Comparing the prices in Tables 2.7 and 2.8, mean wholesale prices by region are between 0.9 (PADD 3) cents and 1.3 cents (PADD 4) higher with actual refinery consolidation. Consolidation increases wholesale prices on average from 0.7 cpg (CARB gasoline) to 1.5 cpg (Ethanol blended RFG). Thus, the simulation results imply that even with refinery divestitures required as part of mergers, changes in refinery ownership over this period increased prices.

I also estimate the effect of refinery ownership on gasoline price spikes caused by local refinery outages. In Table 2.11, I present the average price differential between the counterfactual and base case for CARB gasoline, Illinois RFG and Wisconsin RFG contingent and uncontingent on refinery outages. Contingent on a local outage, industry consolidation has a much larger effect on ethanol-blended RFG (4.6 cpg in Illinois) than on CARB gasoline (0.9 cpg in California). This suggests that refinery ownership consolidation leads to a greater concentration of ethanol-blended RFG production locally, relative to CARB gasoline production.

Declining Reserve Refining Capacity

I also simulate a counterfactual testing the effect of declining reserve refining capacity. That is, I estimate the price effect of capacity constraints on many of the largest domestic refineries. I specify three counterfactuals, increasing light product production capacity of all domestic refineries by 2.5%, 5% and 7.5%.[41] Allowing capacity to increase has two effects - it relaxes the binding capacity constraint at the most efficient refineries and relaxes the binding capacity constraint in gasoline-importing regions. Increasing refining capacity should reduce prices in all areas as production is shifted to more efficient refineries but should also reduce prices relatively more in gasoline-importing regions. As above, Tables 2.7 and 2.8 present the descriptive statistics for the simulated counterfactual prices by geographic and product market and Table 2.12 presents the simulated price differential between the counterfactual and the base case, conditional and unconditional on refinery outages.

The results in Tables 2.7 and 2.8 are consistent with ex ante predictions. Increasing refinery capacity by five percent lowers prices in all geographic markets between 3.9 and 4.5 cents per gallon. In addition, the districts experiencing the largest price reductions are the Rocky Mountain states (PADD 4 - 4.5 cpg) and New England (PADD 1a - 4.3 cpg). Capacity-constrained geographic regions benefit from both reallocation of production to the most efficient refineries and the relaxation of the binding capacity constraint on local refineries. Areas with excess refining capacity only benefit from the former.

Increasing production capacity of all refineries by five percent does not effect substantively which refineries produce CARB or ethanol-blended RFG gasoline. Thus, the average price differentials reported in Table 2.12 contingent on a local outage and contingent on no outages are statistically indistinguishable.

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[41] In the simulation, refinery cost functions are held constant, to control only for the effect of relaxing the capacity constraint on refineries. Outages are scaled proportionately with increases in capacity.

2.8.3 Sensitivity Analyses

To test the robustness of the estimates in Section 8.1, I test the sensitivity of the simulated prices to the assumption that refiners place a zero probability prior on refinery outages and to changes in the estimated cost, conduct and elasticity parameters.

Forward-Looking Refinery Optimization

To test sensitivity of the results to the assumption that refiners place a zero prior probability on unexpected outages, I simulate a counterfactual in which each risk-neutral refiner places a common, positive prior on outages at each refinery.[42] Each refiner incorporates these priors into her production choice in the first step of the optimization problem. I constrain the continuum of all possible outages to a discrete subset: single, refinery-wide outages. Given the production choices for each element of the state space (each outage contingency), I identify the initial production choice for each market which maximizes each refiner's expected profits. I then simulate prices in each market assuming this initial choice is binding, but allow the refiners to reallocate production in response to the actual refinery outages.

Table 2.13 and 2.14 compare descriptive statistics for simulated prices under base case and forward-looking refinery optimization. Simulated mean prices for ethanol-blended RFG and CARB gasoline are 0.45 cpg and 0.34 cpg lower when refinery optimization decisions incorporate outages than when they do not. Conventional, RFG, jet fuel and distillate mean prices are 0.11 cpg lower to 0.07 cpg higher with expected profit maximization than with profit maximization. This is consistent with ex ante expectations - since outages have the greatest effect on CARB and ethanol-blended RFG, incorporating the possibility of outages will increase production of CARB and ethanol-blended RFG more than other products.

When compared to the magnitude of the effect of incompatible regulations, though, the modelling assumption I make has an effect an order of magnitude less that then

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[42] The common ex ante outage probability is consistent in expectation with the actual outages observed over the study period. Numerically, the probability of a refinery-wide outages at each refinery in each period is 0.0021.

the effect of incompatible regulations. Several explanations exist for the relatively small magnitude of the effect. First, while each refiner's priors of a refinery-wide outage somewhere in the system in a given month is approximately twenty-five percent, each refiner's priors of an outage at a specific refinery is much lower. Since the prior probability of a local refinery outage in Illinois, Wisconsin or California is relatively low, refiners rarely benefit from increasing production of CARB or ethanol-blended RFG above the level of production modelled in the base case.[43] Furthermore, capacity constraints prevent many refiners from increasing production of CARB or ethanol-blended RFG without decreasing production of another product. In choosing to produce more CARB or ethanol-blended RFG, capacity-constrained refineries weigh the benefits of incremental production in the event of a relevant local refinery outage against the incremental production cost of the special gasoline blend and the shadow cost of additional refining capacity.

Estimated Structural Parameters

In addition to testing the sensitivity of the simulation results to the assumption of profit maximization, I also test the sensitivity of the results to variation in the structural parameter estimates. I focus on the six unobserved parameters which have the largest effect on simulated CARB and ethanol-blended RFG prices: demand elasticity (ϵ), the competition coefficient (α), the coefficient on crude oil price (β_2), RFG production costs (β_3), ethanol-blended RFG production costs (β_4) and CARB production costs (β_5). For each of the sensitivity tests, I bound the coefficients at two standard deviations above and below the NLLS estimate reported in Table 2.4. Table 2.15 reports the differential price effect from gasoline content regulations contingent on a local outage. The differentials reported in Table 2.15 are equivalent to the first column in Table 2.10. Table 2.16 reports the percentage of local price volatility mitigated if CARB and ethanol-blended RFG regulations were compatible with federal RFG.

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[43] Common refinery priors for an outage in Illinois or Wisconsin is 0.015 and for an outage in California is 0.05.

The first sensitivity analyses test the robustness of the estimates to changes in the demand elasticity. The effect of content regulations contingent on a local outage is positively correlated with demand elasticity. If demand curves are less elastic, a supply shock of similar magnitude has a greater effect on prices. This is consistent with the results in Table 2.15, in which the estimated effect of content regulations contingent on a local outage decrease as demand becomes more elastic. In either case, though, the estimated proportion of volatility from local outages mitigated by fuel compatibility is relatively close to the results from the NLLS minimizing parameter vector, 69 and 73 percent for California, 90 to 95 percent for Illinois and 89 to 94 percent for Wisconsin. In addition to the testing the sensitivity of the simulation results to demand elasticities two standard errors above and below the NLLS point estimate, I also test the robustness of the simulation results to demand elasticity of -0.23, the median short-run gasoline demand elasticity estimate across the 363 estimates used for meta-analysis by Espey(1998). Again, the results are consistent with the intuition that refinery outages will have a larger effect on prices as demand becomes less elastic.

In general, the other sensitivity results presented in Table 2.15 are consistent with the ex ante predictions. Two components drive how variations in the estimated parameters affect estimates in Table 2.15: the incremental production costs associated with the regional content regulations and the degree to which production of the special blend is concentrated at local refineries. As a result, parameters affecting these two factors have the greatest effect on the price differential between the base case and counterfactual simulations. For example, cost coefficients on ethanol-blended RFG and CARB should be positively correlated with the differentials reported in Table 2.15, since each represents the incremental production costs to refiners. Across the sensitivity tests, the effect of compatibility contingent on local outages varies from 8.5 to 11.0 for California, 7.8 to 11.7 for Illinois and 8.2 to 12.3 for Wisconsin.

While the point estimates of the effect of content regulations contingent on a local outage vary by twenty percent in some sensitivity tests, the percent of the price volatility from a local outage mitigated by content regulations, reported in Table

2.16, seems fairly robust to changes in the parameters. Across the sensitivity tests, mitigation of local outages varies from 67 to 74 percent for California, 88 to 98 percent for Illinois and 90 to 99 percent for Wisconsin. This suggests that, although the magnitude of the effect of content regulation does vary to a degree, the basic conclusion is robust, that compatibility with federal RFG has the potential to mitigate a significant proportion of the effect of local refinery outages, especially in Illinois and Wisconsin.

2.9 Conclusion

In this paper, I use a structural model of refinery production to estimate two effects of regional gasoline content regulations on gasoline prices in California, Illinois and Wisconsin. Using a constructed dataset of refinery outages, I am able to separate the effect of the regulations on prices through increased production costs and the effect of the regulations on prices through fuel incompatibility. Point estimates for the effect of the former are 4.5, 3.0 and 2.9 cents per gallon in California, Illinois and Wisconsin. The effect of the latter, contingent on a local refinery outage, is estimated as 4.8, 6.6 and 7.1 cents in California, Illinois and Wisconsin. Controlling for the magnitude of local outages in these areas, I estimate that 72, 91 and 92 percent of price spike created by a local refinery outage could be mitigated by compatibility with federal reformulated gasoline. The sensitivity results in section 8 suggest that the conclusions are robust to changes in parameter estimates and to the assumptions of refiner's priors regarding the probability of unexpected outages. In particular, is seems that across the sensitivity tests, in all cases gasoline compatibility with federal RFG may play an important role in moderating price spikes from refinery outages in California, Illinois and Wisconsin.

In addition, I simulate several counterfactuals to estimate the effects on wholesale prices of changing refinery ownership over 1995 through 2001 and limited additions to domestic refining capacity. I find that changes in refinery ownership increase prices by 1.4 to 1.5 cpg in Illinois and Wisconsin and by 0.73 cents per gallon in California.

A five-percent increase in domestic refining capacity reduces prices 3.7 to 3.8 cents per gallon in Illinois and Wisconsin and 4.3 cents per gallon in California. Looking across PADD districts, I find that increasing refining capacity lowers prices most in regions which currently import petroleum products from other regions, namely the Rocky Mountain states (PADD 4) and the East Coast (PADD 1).

This study raises clear public policy implications. Back of the envelope calculations estimate the cost, through 2001, of content regulations incompatible with federal RFG standards in California, Illinois and Wisconsin at \$4.3 billion, \$670 million and \$160 million respectively relative to federal RFG. Since the motivation for these regulations is to reduce air pollution, it is important to assess whether CARB gasoline and ethanol-blended RFG constitute cost-effective methods for achieving this goal. To the extent that supplementary content regulations imposed by these states have little effect on mobile emissions, lower cost strategies may exist to reduce emissions in these states.

Table 2.1: Unexpected Refinery Outages Affecting Production of Light Products.

State	Refinery	Refiner	Outage Nature	Outage Date	Repair Date	Outage Severity (000s/gals/day)	Sources
TEXAS	Pasadena	Crown Central Petro Group	Explosion prior to maintenance of distillation tower	23-Nov-01	21-Dec-01	4,200	c
LOUISIANA	Lake Charles	Citgo	Explosion and fire at hydrocracker unit	21-Sep-01	17-Oct-01	1,537	a, c
DELAWARE	Delaware City	Motiva	Maintenace at crude unit due to acid spill	20-Sep-01	10-Oct-01	7,014	c
OKLAHOMA	Ponca City	Conoco	Removal of 54kbbl/day cat cracker from service	16-Aug-01	8-Sep-01	2,268	a
ILLINOIS	Lemont	PDV America/Citgo	Fire at Lemont Refinery crude distillation unit	14-Aug-01	25-Sep-01	7,014	a, b
TEXAS	Deer Park	deer park ltd	Fire closes facility for several days	8-Aug-01	11-Aug-01	13,461	a
DELAWARE	Delaware City	Motiva	Fire and acid spill	17-Jul-01	20-Sep-01	2,338	c
TEXAS	Three Rivers	Ultramar Diamond Shamrock	Fire and Explosion in alkylation unit	9-Jul-01	23-Jul-01	3,755	a, c
TEXAS	Port Arthur	Blackstone Group	Lightning strike necessitates maintenance of distillation tower	1-May-01	7/6/2001	840	a
UTAH	Woods Cross	Inland	Fire prompts water upgrade	4-Jul-01	4-Aug-01	437	a
LOUISIANA	Norco	Orion	Lightning strikes gasoline storage tank	7-Jun-01	10-Jun-01	3,255	a, b, c
CALIFORNIA	Los Angeles	BP	Fire at catalytic cracking unit	26-May-01	10-Jun-01	4,032	b
ALABAMA	Tuscoloosa	Hunt Refining	Major fire at refinery	13-May-01	15-May-01	1,092	a, b
ILLINOIS	Wood River	Tosco	Fire in pump of distillation unit.	28-Apr-01	22-May-01	5,282	a, b
CALIFORNIA	Benicia	ExxonMobil	Delayed restart to Benecia	1-Mar-01	1-Apr-01	5,670	a
ILLINOIS	Blue Island	Clark	Refinery upgrades.	1-Jan-01	1-Oct-01	3,041	a
PENNSYLVANIA	Philadelphia	Sunoco	Fire at distillation tower.	7-Sep-00	28-Sep-00	5,460	c, d
ILLINOIS	Robinson	Marathon Ashland	Fire at reformer and hydrocracker.	5-Aug-00	5-Sep-00	1,050	c
PENNSYLVANIA	Philadelphia	Sunoco	Catalyst release shuts down catalytic cracking unit	21-Jun-00	5-Jul-00	4,767	c
LOUISIANA	Norco	Orion	Explosion of diesel fuel.	10-Jun-00	24-Jun-00	3,612	a
TEXAS	Port Arthur	Blackstone Group	Unscheduled outage of distillation unit.	25-May-00	5-Jun-00	8,337	d
LOUISIANA	Shreveport	Pennzoil	Naphtha explosion.	18-Jan-00	2-Feb-00	1,281	a, b, d
OHIO	Toledo	Sunoco	Fire and small explosion near distillation tower.	28-Aug-99	11-Sep-99	3,028	b, d
ALABAMA	Tuscoloosa	Hunt Refining	Fire in processing facility.	18-Aug-99	31-Aug-99	1,092	a
CALIFORNIA	Richmond	Chevron	Fire at refinery.	10-Jul-99	15-Aug-99	5,040	a, d
TENNESSEE	Memphis	Williams	Fire at catalytic cracking unit	16-Jun-99	21-Jun-99	2,688	a
TEXAS	Corpus Christi	Coastal Corp	Fire at reformer.	14-May-99	14-Jun-99	630	a
INDIANA	Whiting	BP	Explosion from leaking jet fuel at catalytic cracker.	20-Apr-99	15-May-99	6,586	a
CALIFORNIA	Los Angeles	Arco	Failure of cogeneration plant halts operation.	27-Mar-99	29-Mar-99	10,731	a
CALIFORNIA	Richmond	Chevron	Fire and explosion in hydrocracking unit.	26-Mar-99	1-Mar-00	1,722	a, d
CALIFORNIA	Avon	Tosco	Fire and explosion at distillation tower.	23-Feb-99	1-Aug-99	6,897	a, c
ILLINOIS	Lemont	Citgo	Fire at distillation unit.	23-Feb-99	6-Mar-99	7,014	a
ARKANSAS	Smackover	Cross Petrol	Explosion at Naphtha tank.	13-Jan-99	10-Feb-99	235	a
LOUISIANA	Belle Chasse	BP	Fire at refinery.	2-Oct-98	5-Oct-98	9,862	a
OKLAHOMA	Ardmore	Ultramar Diamond Shamrock	Fire and power failure at distillation tower.	13-Jul-98	18-Sep-98	2,856	b, d
PENNSYLVANIA	Philadelphia	Sunoco	Power outage necessitates maintenance of catalytic cracker.	26-Jun-98	25-Jul-98	3,066	d
CALIFORNIA	Avon	Tosco	Explosion at hydrocracker.	22-Jan-97	24-Jan-97	2,688	a, d
NEW JERSEY	Bayway	Tosco	Unscheduled maintenance of catalytic cracker.	1-Jan-97	22-Jan-97	5,796	d
ILLINOIS	Blue Island	clark oil	Propane fire spurs damages electrical systems.	19-Oct-96	8-Nov-96	1,303	a, d
OHIO	toledo	BP	Fire at refinery.	15-Oct-96	23-Oct-96	5,880	a
MINNESOTA	Pine Bend	Koch	Lightning necessitates shutdown of distillation unit.	21-May-96	31-May-96	10,080	a
CALIFORNIA	Martinez	Shell	Explosion at hydrotreater.	1-Apr-96	22-Apr-96	3,173	a
COLORADO	Commerce City	TPI	Fire at refinery.	5-Feb-96	19-Feb-96	1,806	a
TEXAS	Texas City	Amoco	Explosion and fire at catalytic cracker at largest US refinery.	25-Jul-95	25-Aug-95	4,070	a

Sources:
(a) Local News Sources
(b) US Chemical Safety Board, Chemical Incident Report Center
(c) Monthly Incident Reports from www.acusafe.com
(d) SEC filings.

Table 2.2: Reduced Form Descriptive Statistics

Variables	Mean	Std. Dev	Min	Max
Gasoline Prices				
DTW Price	79.31	17.81	37.90	151.80
Rack Price	71.99	17.73	34.40	147.90
Retail Price	87.83	18.23	47.40	159.70
Gasoline Volumes				
Conventional Volume	5,319.3	4,640.1	97.4	21,916.1
Oxygenated Volume	2,053.5	2,539.6	0.6	15,720.7
Reformulated Volume	4,746.8	4,996.7	0.9	40,564.6
Content Regulations				
RFG Dummy	0.31	0.46	0.00	1.00
Oxygenated Dummy	0.22	0.41	0.00	1.00
Ethanol Blended RFG Dummy	0.02	0.13	0.00	1.00
Federal Phase 2 RFG Dummy	0.05	0.22	0.00	1.00
Federal Phase 1 RFG Dummy	0.25	0.43	0.00	1.00
CARB Dummy	0.01	0.09	0.00	1.00
Mandatory Ethanol Dummy	0.04	0.19	0.00	1.00
Mandatory Oxygenation Percentage	0.45	0.88	0.00	3.50
Demand Instruments				
State Population (millions)	7.28	7.50	0.63	33.90
Population Density	190.6	252.2	1.1	1,143.7
Per Capita Income (000s)	23.82	4.56	15.22	40.64
Total Licensed Drivers (millions)	3.87	4.03	0.34	22.40
Registered Autos Per Person	0.70	0.10	0.43	0.96
Registered Buses Per Person	0.00	0.00	0.00	0.01
Registered Motorcycles Per Person	0.03	0.01	0.01	0.07
State Tax	19.83	4.99	7.50	39.00
Federal Gasoline Tax	18.36	0.05	18.30	18.40
Cents Per Gallon Tax	38.19	4.99	25.80	57.30
Crude Spot Prices				
Cushing WTI Spot Price	50.50	11.22	26.99	81.95
Brent North Shore Spot Price	46.91	11.23	23.39	78.57

Table 2.3: Reduced-Form Regressions Results
Dependent Variable: Monthly Average Real Rack Price Net of State and Federal Taxes (cents/gallon)

		Specification	
Variable	Model 1	Model 2	Model 3
CONSTANT	12.550**	61.237**	6.617**
	1.377	0.721	1.428
QUANTITY	0.00047**	-0.00058**	-0.00037*
	0.00015	0.00009	0.00013
WTI MONTHLY CRUDE PRICE	1.159**		1.177**
	0.013		0.009
OXYDUMMY	3.495**	4.696**	4.947**
	0.754	0.437**	0.513
RFGDUMMY	3.839**	4.065**	4.238**
	0.552	0.261	0.354
RFGETHDUMMY^	1.836	1.855*	1.675
	1.793	0.833	1.118
CARBDUMMY^	3.184	5.646**	5.050*
	2.036	1.677	1.974
Geographic Dummy Variables	State	State	State
Temporal Dummy Variables	-	Month-Year	State-Month
Autocorrelation Coefficient	Common	Common	Common
Errors	Heteroskedastic	Heteroskedastic	Heteroskedastic
R-Squared	0.7902	0.9390	0.8722
Estimated Rho	0.615	0.534	0.471

Notes:

* denotes significance at 5% level
** denotes significance at 1% level
^ Both Ethanol requirements for gasoline and CARB gasoline requirements are treated additively to the RFGDUMM
(e.g. Holding all else equal, CARB gasoline prices are greater than conventional gasoline prices by the sum of the coefficients on RFGDUMMY and CARBDUMMY.)

Table 2.4: NLLS Parameter Estimates

Variable	Parameter	Coefficient	Standard Error
Demand Elasticity	epsilon	0.337	0.004
Competition Coefficient	alpha	0.031	0.003
Cost Function Parameters			
Marginal Cost Parameter	beta0	0.436	0.028
Log(Distillation Capacity)	beta1	-0.867	0.023
WTI Crude Price	beta2	0.765	0.008
RFG Dummy	beta3	5.009	0.383
Ethanol-blended RFG Dummy	beta4	8.210	0.737
CARB Dummy	beta5	10.517	0.374
Jet Fuel Dummy	beta6	-1.758	0.209
No. 2 Distillate Dummy	beta7	-3.996	0.179
R-squared (quantities)		0.998	
R-squared (prices)		0.926	

Note: Coefficients jointly minimize NLLS. Solution based on gradient of steepest ascent numerical search algorithm.

Table 2.5: Descriptive Statistics by PADD and Estimation Technique

	PADD Region						
	1a	1b	1c	2	3	4	5
Actual Prices							
Mean	69.56	68.82	66.74	70.35	66.12	74.84	74.91
Standard Deviation	16.67	16.95	16.36	18.28	16.61	17.26	18.82
Max	121.00	119.30	116.20	147.90	114.20	124.20	130.80
Min	34.50	33.40	34.00	34.70	31.60	38.40	40.20
Estimated Prices - Structural Model							
Mean	71.17	67.62	67.35	69.92	68.99	73.29	75.14
Standard Deviation	14.73	14.74	14.67	16.64	15.56	17.39	16.99
Max	108.45	104.37	104.16	117.02	108.55	117.57	128.56
Min	35.06	32.50	32.60	33.63	32.52	33.33	33.20
Estimated Prices - Reduced Form Model 1							
Mean	70.82	70.42	67.93	70.89	68.48	75.52	76.94
Standard Deviation	16.50	16.89	16.75	17.13	16.71	16.20	16.69
Max	118.94	117.73	116.01	120.73	117.94	123.52	125.96
Min	38.05	36.02	35.55	36.04	34.85	39.86	43.00

Table 2.6: Descriptive Statistics by Formulation and Estimation Technique

	Formulation					
	Conventional	RFG	Ethanol-Blended RFG	CARB Gasoline	Jet Fuel	Distillate
Actual Prices						
Mean	70.24	72.54	75.85	81.81	65.72	64.35
Standard Deviation	17.25	17.75	19.69	20.81	16.96	17.13
Max	129.20	139.30	147.90	130.80	115.80	120.30
Min	34.40	38.50	43.00	49.40	31.60	31.70
Estimated Prices - Structural Model						
Mean	69.88	73.28	76.83	87.49	66.98	65.12
Standard Deviation	15.94	15.30	17.19	16.50	15.42	15.61
Max	117.57	118.64	117.02	128.56	111.61	109.41
Min	34.48	39.04	45.37	49.59	32.93	32.50
Estimated Prices - Reduced Form Model 1						
Mean	70.52	72.69	75.75	82.59		
Standard Deviation	16.87	17.03	17.32	17.85		
Max	124.94	125.96	120.73	125.76		
Min	34.85	39.31	43.36	49.39		

Table 2.7: Counterfactual Results - Mean Wholesale Price by PADD

Simulation Run	PADD Region 1a	1b	1c	2	3	4	5
Base Case	71.17	67.62	67.35	69.92	68.99	73.29	75.14
Counterfactuals							
CARB Compatibility	71.45	67.92	67.49	70.03	69.12	73.36	74.87
Ethanol-Blended RFG Compatibility	71.16	67.93	67.15	69.72	68.53	73.75	75.21
Constant Refinery Ownership	70.22	66.52	66.35	68.68	68.06	72.04	73.98
2.5% Additional Refining Capacity	68.90	65.42	65.08	67.86	66.74	70.84	73.08
5.0% Additional Refining Capacity	66.93	63.49	63.07	66.02	64.72	68.76	71.29
7.5% Additional Refining Capacity	65.17	61.75	61.26	64.38	62.92	67.13	69.94

Table 2.8: Counterfactual Results - Mean Wholesale Price by Formulation

Simulation Run	Formulation Conventional	RFG	Ethanol-Blended RFG	CARB Gasoline	Jet Fuel	Distillate
Base Case	69.88	73.28	76.83	87.49	66.98	65.12
Counterfactuals						
CARB Compatibility	69.99	73.75	76.78	82.13	67.11	65.25
Ethanol-Blended RFG Compatibility	69.94	73.15	72.88	87.52	67.34	65.27
Constant Refinery Ownership	68.75	72.26	75.36	86.76	65.87	64.01
2.5% Additional Refining Capacity	67.73	71.08	74.88	85.21	64.65	62.80
5.0% Additional Refining Capacity	65.83	69.15	73.06	83.22	62.62	60.77
7.5% Additional Refining Capacity	64.18	67.42	71.61	81.51	60.89	59.05

Table 2.9: Simulated Wholesale Price Differential Due to Unexpected Refinery Outages
(cents per gallon, standard errors in parenthses)

	Conditional on Outage Type			
State	Local Outage	Regional Outage	No Refinery Outage	Unconditional
California	**6.68**		**0.07**	**0.85**
	(0.08)		(0.001)	(0.02)
Illinois	**7.28**	**2.38**	**-0.02**	**0.88**
	(0.27)	(0.04)	(0.08)	(0.13)
Wisconsin	**7.72**	**3.47**	**0.00**	**1.46**
	(0.28)	(0.07)	(0.10)	(0.16)

Table 2.10: Simulated Wholesale Price Differential Due to Fuel Compatibility
(cents per gallon, standard errors in parenthses)

	Conditional on Outage Type			
State	Local Outage	Regional Outage	No Refinery Outage	Unconditional
California	**9.26**		**4.46**	**5.36**
	(0.47)		(0.40)	(0.43)
Illinois	**9.57**	**4.71**	**2.97**	**3.76**
	(0.72)	(0.76)	(0.83)	(0.70)
Wisconsin	**9.92**	**5.01**	**2.86**	**4.17**
	(0.71)	(0.79)	(0.84)	(0.68)

Table 2.11: Simulated Wholesale Price Differential Due to Refinery Consolidation
(cents per gallon, standard errors in parenthses)

	Conditional on Outage Type			
State	Local Outage	Regional Outage	No Refinery Outage	Unconditional
California	**1.41**		**0.54**	**0.73**
	(0.11)		(0.07)	(0.08)
Illinois	**6.02**	**1.30**	**0.39**	**1.40**
	(0.58)	(0.21)	(0.08)	(0.17)
Wisconsin	**5.45**	**1.11**	**0.65**	**1.54**
	(0.56)	(0.21)	(0.10)	(0.19)

Table 2.12: Simulated Wholesale Price Differential Due from Five Percent Increase in Refining Capacity
(cents per gallon, standard errors in parenthses)

	Conditional on Outage Type			
State	Local Outage	Regional Outage	No Refinery Outage	Unconditional
California	**3.90**		**4.47**	**4.27**
	(0.51)		(0.29)	(0.32)
Illinois	**3.85**	**4.31**	**3.86**	**3.78**
	(1.27)	(1.08)	(0.18)	(0.18)
Wisconsin	**3.91**	**4.39**	**3.85**	**3.75**
	(1.21)	(1.08)	(0.22)	(0.22)

Note: Local outages for California are defined as in-state outages. Local outages for Illinois and Wisconsin are defined as outages in either Illinois or Wisconsin. Regional outages for Illinois and Wisconsin are non-local outages occurring within PADD 2 (IL, WI).

Table 2.13: Descriptive Statistics For Simulations Based on Profit and Expected Profit Maximization, by PADD

	PADD Region						
	1a	1b	1c	2	3	4	5
Simulated Prices Based on Refinery Profit Maximization							
Mean	71.17	67.62	67.35	69.92	68.99	73.29	75.14
Standard Deviation	14.73	14.74	14.67	16.64	15.56	17.39	16.99
Max	108.45	104.37	104.16	117.02	108.55	117.57	128.56
Min	35.06	32.50	32.60	33.63	32.52	33.33	33.20
Simulated Prices Based on Refinery Expected Profit Maximization							
Mean	71.44	67.50	66.77	70.01	68.56	73.85	74.82
Standard Deviation	14.61	14.73	14.62	16.46	15.57	17.08	16.96
Max	108.24	104.16	103.96	116.76	108.36	117.32	128.16
Min	35.03	32.47	32.57	33.60	32.48	33.96	33.20

Table 2.14: Descriptive Statistics For Simulations Based on Profit and Expected Profit Maximization, by Formulation

	Formulation					
	Conventional	RFG	Ethanol-Blended RFG	CARB Gasoline	Jet Fuel	Distillate
Simulated Prices Based on Refinery Profit Maximization						
Mean	69.88	73.28	76.83	87.49	66.98	65.12
Standard Deviation	15.94	15.30	17.19	16.50	15.42	15.61
Max	117.57	118.64	117.02	128.56	111.61	109.41
Min	34.48	39.04	45.37	49.59	32.93	32.50
Simulated Prices Based on Refinery Expected Profit Maximization						
Mean	69.77	73.35	76.38	87.15	67.03	65.12
Standard Deviation	15.89	15.19	17.10	16.41	15.28	15.44
Max	117.32	118.52	116.76	128.16	111.45	107.81
Min	34.74	39.12	45.91	49.59	32.92	32.47

Table 2.15: Simulated Wholesale Price Effect Due to Fuel Compatibility Contingent on Local Outage

			Wholesale Price Differential Due to Fuel Compatibility Contingent on Local Outage		
Parameter	Initial Value	Adjusted Value	California	Illinois	Wisconsin
Base Case			9.3	9.6	9.9
Demand Elasticity	-0.337	-0.230	11.0	11.7	12.3
Demand Elasticity	-0.337	-0.329	9.2	9.9	10.2
Demand Elasticity	-0.337	-0.346	9.2	9.3	9.5
Competition Coefficient	0.031	0.0359	9.4	7.8	8.2
Competition Coefficient	0.031	0.0251	9.2	9.3	9.7
WTI Crude Price	0.765	0.780	9.4	9.6	9.8
WTI Crude Price	0.765	0.749	9.3	9.6	9.9
Federal RFG MC Dummy	5.009	5.7753	8.5	8.9	9.2
Federal RFG MC Dummy	5.009	4.2429	9.9	10.3	10.7
Ethanol RFG MC Dummy	8.210	9.685	9.1	10.9	11.3
Ethanol RFG MC Dummy	8.210	6.735	9.3	8.3	8.6
CARB MC Dummy	10.517	11.264	10.0	9.7	9.9
CARB MC Dummy	10.517	9.770	8.7	9.7	10.0

Note: Sensitivity results based on simulations deviating from structural model parameter estimates.

Table 2.16: Simulated Price Volatility From Local Outage Mitigated By Compatible Regulations

Parameter	Initial Value	Adjusted Value	Percent of Outage Price Volatility Mitigated By Federal-RFG Compatibility		
			California	Illinois	Wisconsin
Base Case			72%	91%	92%
Demand Elasticity	-0.337	0.230	67%	98%	99%
Demand Elasticity	-0.337	-0.329	69%	95%	94%
Demand Elasticity	-0.337	-0.346	73%	90%	89%
Competition Coefficient	0.031	0.0359	74%	88%	90%
Competition Coefficient	0.031	0.0251	70%	92%	92%
WTI Crude Price	0.765	0.780	74%	94%	93%
WTI Crude Price	0.765	0.749	72%	93%	92%
Federal RFG MC Dummy	5.009	5.7753	70%	91%	92%
Federal RFG MC Dummy	5.009	4.2429	72%	92%	93%
Ethanol RFG MC Dummy	8.210	9.685	70%	91%	92%
Ethanol RFG MC Dummy	8.210	6.735	73%	92%	92%
CARB MC Dummy	10.517	11.264	73%	93%	93%
CARB MC Dummy	10.517	9.770	72%	92%	92%

Note: Sensitivity results based on simulations deviating from structural model parameter estimates.

Figure 2.1: Average Monthly Prices for Crude Oil, CARB gasoline, Illinois Ethanol-Blended RFG and Texas RFG Jan 1995 - Dec 2003

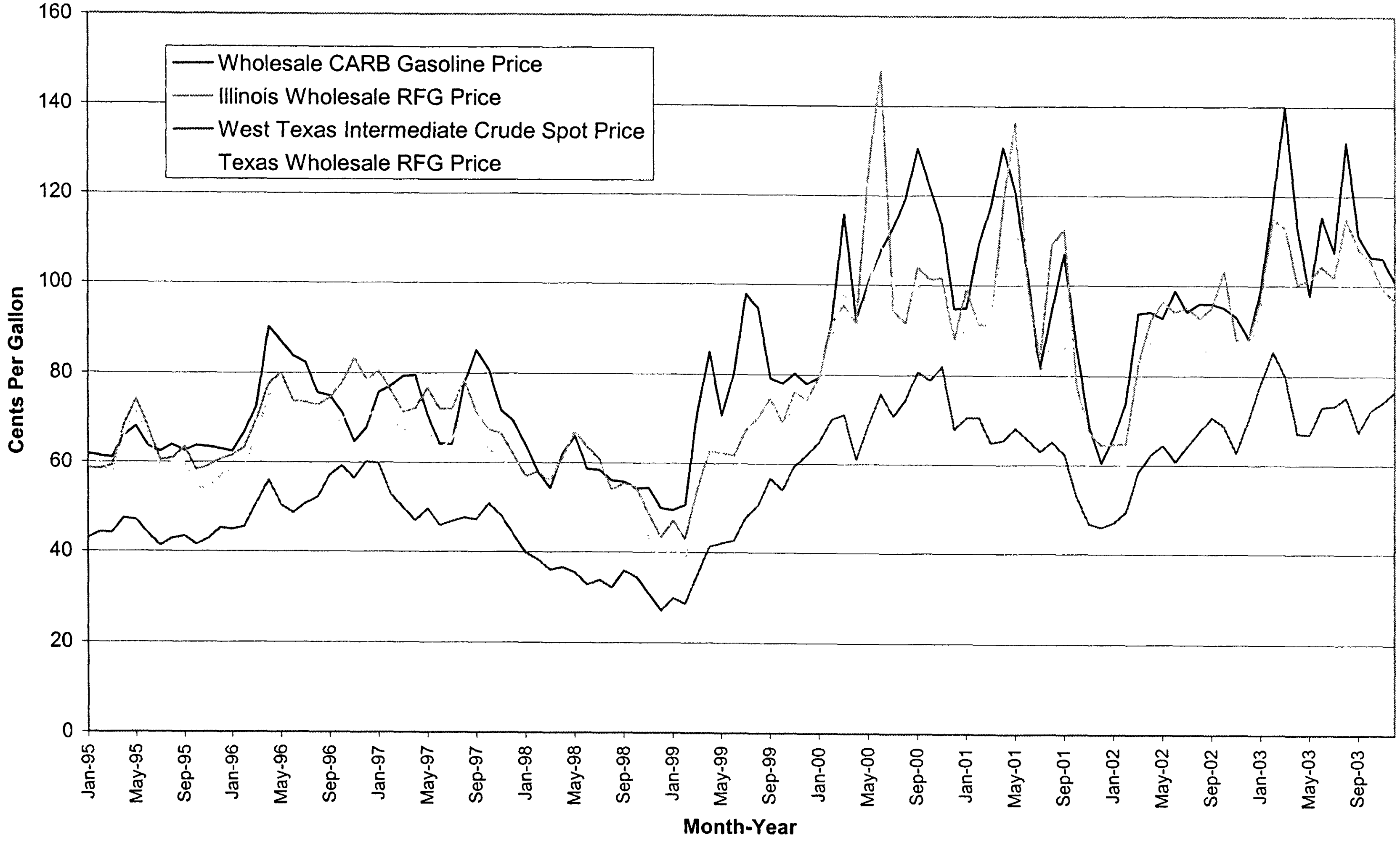


Figure 2.2: CARB/WTI Spot and IL RFG/WTI Spot Differentials
Jan 1995 - Dec 2001

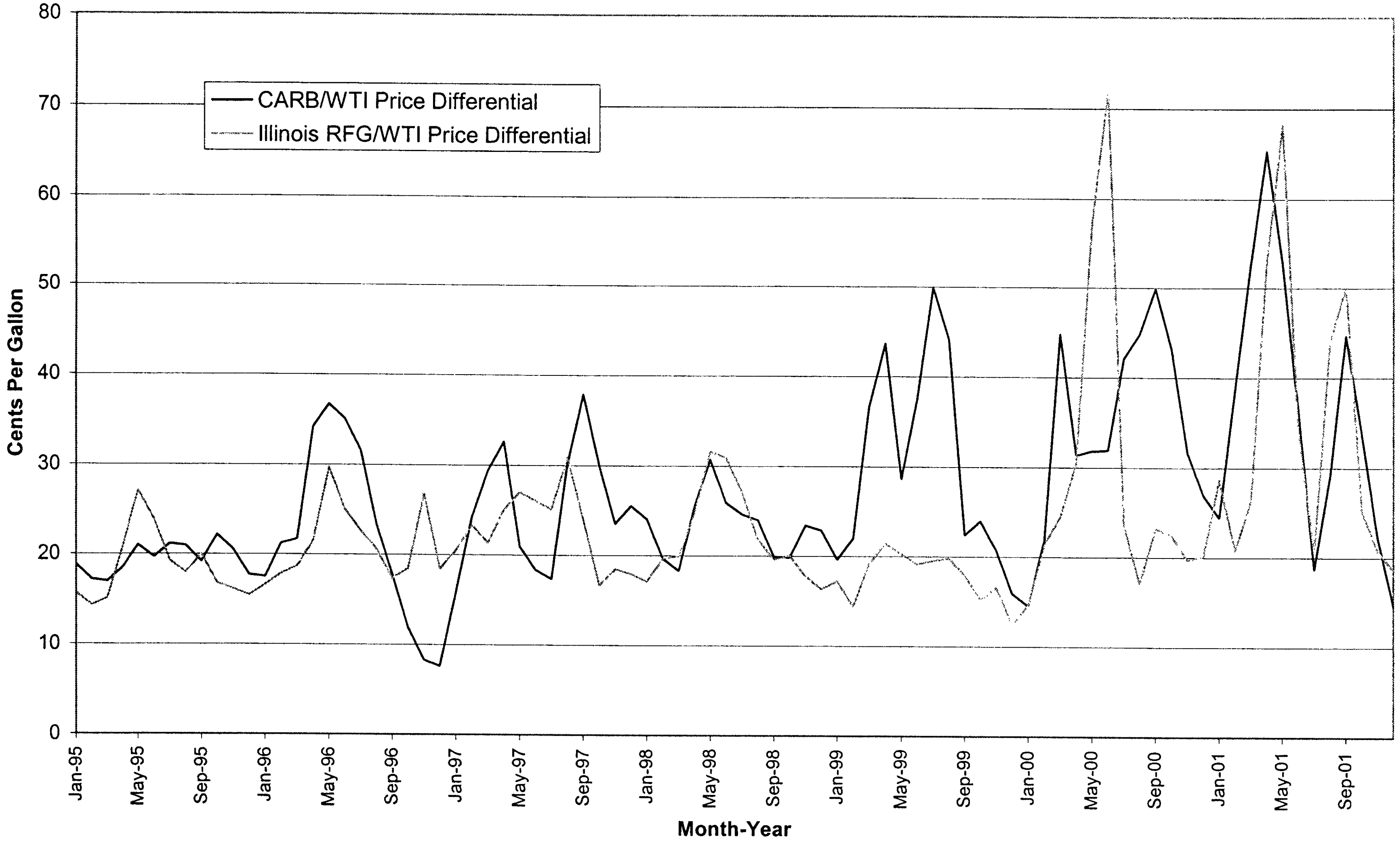


Figure 2.3: Oil Refineries and Refined Product Movements

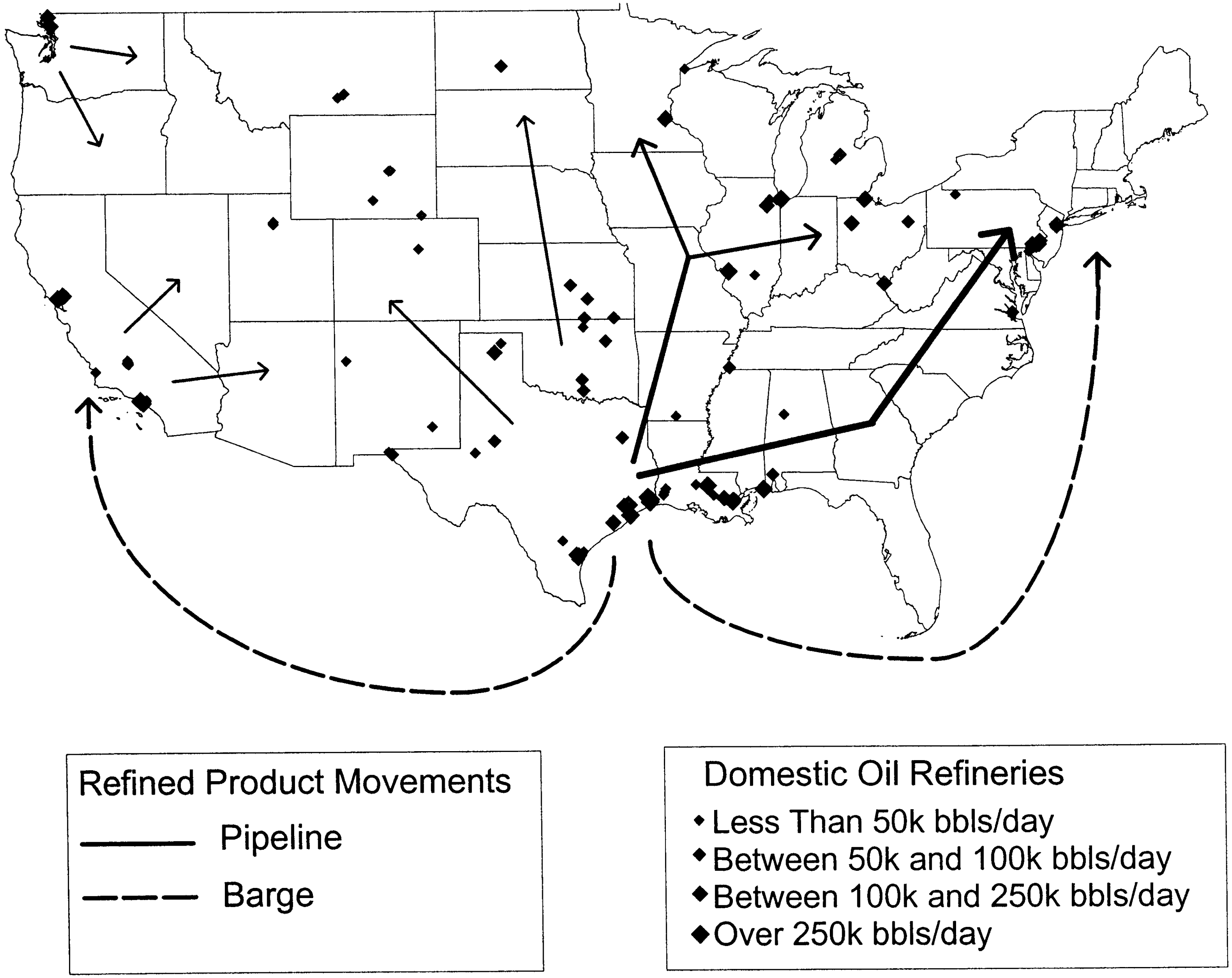
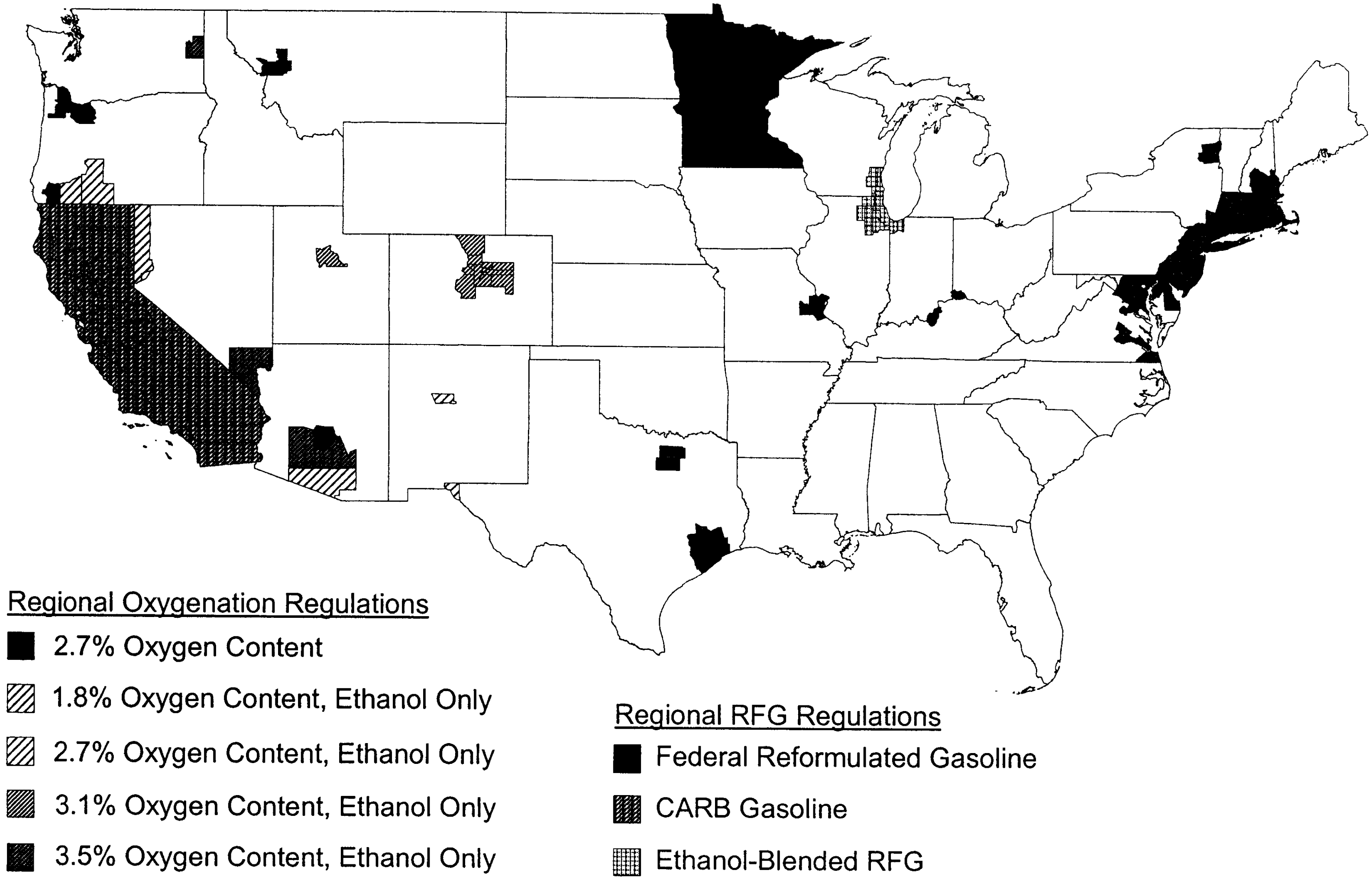


Figure 2.4: Regional Gasoline Content Regulations



Note: Minnesota mandates year-round oxygenation. Other oxygenation mandates only affect winter gasoline content.

Chapter 3

Endogenous Facility Reliability: Evidence From Oil Refinery Fires

3.1 Introduction

Regulatory agencies are often directed to conduct informal studies or formal investigations of unregulated markets in which prices fluctuate dramatically. Recent examples include a Federal Trade Commission (FTC) study of the Midwest Gasoline Price Spikes in the Spring of 2000 and a Federal Energy Regulatory Commission (FERC) study of the California electricity market during the summer of 2000. The primary objective of each of the studies is to identify factors which led to high prices in each market - as part of this analysis, both the FTC and FERC studies discuss whether or not evidence exists that producers in each market withheld output in order to raise prices.

One of the challenges of identifying evidence of explicit withholding by producers in markets is identifying whether or not reductions in supply are strategic or simply the result of unanticipated shocks which affect production. In the California electricity market during the summer of 2000, for example, a number of generating plants were unavailable for production at times when prices were high. The FERC report discusses this as am important factor, while recognizing difficulties with determining whether or not this unavailability was strategic in nature.

> An increased level of unplanned outages at generating plants is another key factor limiting available generation supply in 2000... There are several potential explanations for the increased level of outages... One possibility is that fewer resources are being devoted to planned maintenance... A final possibility is just the opposite: owners could be withholding by taking plants out of service at critical times to drive up prices.[1]

The inability of regulators to verify whether or not "unplanned" outages announced by producers are actually voluntarily withheld production presents a significant problem for policy makers assessing the competitiveness of these markets. Joskow and Kahn(2002) and Borenstein, Bushnell and Wolak(2002) study high electricity prices in California during the summer of 2000. Both studies simulate competitive prices for electricity and then compare simulated and actual prices to quantify the proportion of the high electricity prices attributable to market power. Although neither study is able distinguish if "the units were suffering from unusual operation problems or they were being withheld from the market to increase prices,"[2] both investigate whether outage patterns are consistent with a model of strategic withholding. Joskow and Kahn find evidence of below capacity production at all suppliers in California, with the exception of the generator which signed long-term forward contracts with distribution companies and, consequently, had the least incentive to withhold production from the spot electricity market.

Harvey, Hogan and Schatzki(2004) study outages at Mirant's generating plants in California during 2000 and similarly test whether the production during this period is consistent with strategic withholding. Estimates from their hazard model suggest that, although the level of unplanned outages was higher during this period, the increase was due to extended periods of operation without maintenance prior to and during the summer of 2000. They conclude that, although anecdotal evidence may suggest that some strategic withholding occurred in California, after controlling for

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[1] Source: FERC Staff Report on Western Markets and the Causes of the Summer 2000 Price Abnormalities - Part I, Section 2, November 1, 2000.

[2] See Joskow and Kahn at 3

maintenance schedules, Mirant's actual production during this period was higher than the hazard model predicts.

In this paper, I propose an alternative explanation for why a correlation may exist between the incentives for withholding and facility reliability, absent strategic withholding by producers. I specify a model in which a firm's choice of output and maintenance affect the likelihood that a facility will be available for operation. Allowing for endogenous outage probability, I study the effect of ownership of more than one facility in a geographic market on facility operation, and hence outages. Intuitively, even if it is not unilaterally profitable for a firm to strategically withhold production from the market, if unanticipated outages increase prices, the incentives to operate and maintain facilities will differ for firms that own more than one facility.

In order to study the effect of incentives on unplanned outages, I study fires, explosions and other unanticipated incidents at domestic oil refineries. Importantly, unlike outages at power plants, these incidents are also verifiable, and thus, it is reasonable to think of them as unrelated to explicit strategic withholding by refiners. I construct a dataset of characteristics and ownership of domestic oil refineries and collect data on unanticipated incidents at the refineries. I then estimate the probability of an unanticipated incident occurring as a function of the amount of additional local refining capacity owned by the refinery owner. I find evidence consistent with the predictions of the theoretical model - that a positive correlation exists between ownership of more than one refinery in an area and the probability of unanticipated events. Moreover, the relationship between expected incident probability and ownership is greatest in markets with special gasoline formulations, which are the markets in which a refinery outage has the largest effect of gasoline prices. In these markets, I estimate that the expected probability of an unplanned incident is 30 percent greater for an affiliated refinery than it is for an unaffiliated refinery. My analysis, though, cannot identify a causal relationship between the two - I am unable to rule out the possibility that the correlation I identify arises from refiner selection of a portfolio of assets based on facility-specific incident probability observable by the refiner.

This paper also provides descriptive statistics regarding refinery fires and explosions. To the extent that refinery incidents affect prices of refined petroleum products, this information provides the descriptive statistics regarding facility supply shocks affecting domestic refining of crude oil, useful to policy makers projecting refinery availability.

Section 2 discusses the previous academic literature related to facility reliability. In Section 3, I present a model in which ownership of more than one facility affects the facility reliability and present several testable implications of the model. In Section 4, I describe my dataset as well as provide descriptive statistics about the refinery outages I identify. Section 5 presents my econometric approach, results and sensitivity tests of my model. Section 6 summarizes the findings and discusses policy implications.

3.2 Relevant Literature

A number of related papers study markets or models in which production availability is uncertain. The literature focuses primarily on the electricity industry and is broadly organized into papers studying the effects of exogenously uncertain production on prices and welfare[3], and papers considering either market-level or firm-level factors affecting the availability or reliability of supply. Papers studying market-level incentives include theoretical papers (e.g., Fraser(1994)) and empirical paper (e.g., Sturm(1995)). Fraser derives optimal monopolist production and reliability provision under price-caps which do or do not incorporate incentives for service reliability. Sturm specifies a structural model of nuclear power plant failure and repair. Sturm uses panel data on European nuclear power plant operation and maintenance to explain differences in availability and reliability across different countries. Sturm estimates costs of planned refueling outages and unplanned outages and interprets

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[3] For example, Saving and DeVany(1981) identify optimal peak-load prices in a market with exogenous supply shocks. Kleindorfer and Fernando(1993) derive the welfare effect exogenous supply shocks in a market in which demand is a function of both price and reliability. Tishler(1993) derives and estimates costs from uncertain electricity supply on a sample of industries which use electricity as an input to production.

differences in costs across countries as different national incentive schemes for performance. Sturm then simulates production under different cost parameters to identify the effect of cost incentives on performance.

Unlike studies of market-level incentives, this paper focuses on facility-level incentives for operation and reliability, arising from ownership of more than one refinery in a geographic market. In estimating facility-level reliability from variation in facility-level incentives, the most closely related literature is Joskow and Rozanski(1979), Joskow and Schmalensee(1988) and Rothwell(1996), all of which study the facility-level operation and reliability of electric generating plants. Joskow and Rozanski test for evidence of learning-by-doing in both the operation and construction of nuclear power plants. While Joskow and Rozanski look at output rather than plant outages, they do identify improving availability rates for nuclear power plants consistent with learning. In addition, after controlling for plant vintage and learning, they find lower availability rates for large power plants relative to small power plants. Joskow and Schmalensee focus on efficiency and availability of coal-fired power plants, and estimate vintage and age effects, as well as generator-specific effects for generators with internal construction and engineering groups. Rothwell studies the effect of changes in organizational hierarchy at a set of domestic nuclear power plants. Rothwell estimates separate hazard functions for both operation and repair and finds some evidence that horizontal as opposed to vertical hierarchy improves the duration of operation at nuclear plants.

This paper approaches facility reliability from an incentive perspective - that is, if the operation of a refinery has an effect on the likelihood of unplanned outages, changes in ownership that affect the operation of refineries will also impact outage probability. This relationship, between ownership incentives and unanticipated outages, is not addressed by the previous literature. Covering a period with a number of horizontal mergers within the petroleum industry, many of which involved regulatory-driven divestitures, I exploit variation arising from changes in ownership to identify the effect on the probability of refinery fires or explosions.

3.3 A Model of Endogenous Reliability

I model a static game in which firms choose strategic variables that affect facility reliability. Applied to the refining industry, I consider refiners choosing output and maintenance, both of which might affect the probability of a fire or explosion. I then consider the incentives for the choice of output and maintenance, as a function of whether or not a firm owns more than one facility in a geographic market.

Consider N symmetric risk-neutral facilities, indexed by $i \in \{1, 2, \ldots, N\}$. Initially, I consider the case in which each facility is owned by a different firm. Firms play a single period static game in which they simultaneously choose two strategic variables: output of a homogenous good denoted q_i and the extent of maintenance m_i.[4] I assume the costs of output and maintenance are separable, where $c(q_i, m_i) = c_p(q_i) + c_m(m_i)$ and $c'_p, c''_p, c'_m, c''_m > 0$.[5] Let $q = [q_1, q_2, \ldots, q_n]$ and $m = [m_1, m_2, \ldots, m_n]$ denote the vectors of the choices of output and maintenance of all N firms.

To incorporate facility reliability, I assume that firm choice of q_i and m_i affect the probability that facility i is available for operation. Letting x_i denote a random Bernoulli variable identifying whether a facility is available for operation,

$$\begin{aligned} x_i &= 1 \text{ with probability } \lambda_\mathrm{i}(\mathrm{q_i}, \mathrm{m_i}) \\ &= 0 \text{ with probability } 1 - \lambda_\mathrm{i}(\mathrm{q_i}, \mathrm{m_i}). \end{aligned}$$

where $\frac{\partial \lambda_i}{\partial q_i}, \frac{\partial^2 \lambda_i}{\partial {q_i}^2} \geq 0$ and $\frac{\partial \lambda_i}{\partial m_i}, \frac{\partial^2 \lambda_i}{\partial {m_i}^2} \leq 0$. Letting $X = [x_1, x_2, \ldots, x_N]$ be the vector created by independent realizations of the N Bernoulli variables, let the inverse demand curve faced by firm i, given by

$$P_i(q, X) = P_i(q_1 x_1, q_2 x_2, \ldots, q_N x_N),$$

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[4] A two-step game consisting of sequential choice of maintenance followed by output is analogous to the entry game studied in Fudenberg and Tirole (1984), in which refiners follow a "Top Dog" strategy, initially overinvesting in maintenance to improve their competitive position at the beginning of the second stage of the game.

[5] I assume cost-separability for expositional convenience. Allowing for maintenance costs to be a function of both m_i and q_i does not change the implications of the model.

be a function of the production of all facilities after the realization of X.[6] Thus, a firm owning facility i chooses q_i and m_i to maximize expected profit, where the expectation is taken with respect to X and is given by

$$E_X[\Pi_i(q,m)] = E_X[P_i(q,X)x_iq_i - c_p(x_iq_i) - c_m(m_i)].$$

Conditioning on the realization of x_i, the expected profit is

$$E_X[\Pi_i(q,m)] = \lambda_i E_X[P_i(q,X)x_iq_i|x_i = 1] - \lambda_i c_p(q_i) - (1-\lambda_i)c_p(0) - c_m(m_i).^{[7]}$$

Taking the derivative of expected profit with respect to q_i and m_i, I define the best response function of firm i given the choices of the other $N-1$ firms. The joint solution $q_i^*(q_{-i},m)$ and $m_i^*(q,m_{-i})$ that set the first-order conditions equal to zero defines the reaction functions of firm i.

$$\begin{aligned}\frac{\partial E_X[\Pi_i]}{\partial q_i} &= \lambda_i\left[\frac{\partial E_X[P_i(q,X)x_iq_i|x_i = 1]}{\partial q_i} + \frac{\partial c_p(q_i)}{\partial q_i}\right] \\ &\quad + \frac{\partial \lambda_i}{\partial q_i}[E_X[P_i(q,X)x_iq_i|x_i = 1] - (c_p(q_i) - c_p(0))] \\ &= 0\end{aligned}$$

$$\begin{aligned}\frac{\partial E_X[\Pi_i]}{\partial m_i} &= \frac{\partial \lambda_i}{\partial m_i}E_X[P_i(q,X)x_iq_i|x_i = 1] - \frac{\partial \lambda_i}{\partial m_i}(c_p(q_i) - c_p(0)) + \frac{\partial c_m(m_i)}{\partial m_i} \\ &= 0.\end{aligned}$$

The terms of the first-order conditions can be interpreted as either direct effects on profits of refinery i or as indirect effects of profits through changes in facility reliability. In the case of the first order condition for q_i, the first term line is the direct effect of an increase in output on expected profits. The second line is the the indirect effect of

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[6] With homogenous goods and no transportation costs, all facilities face an identical inverse demand curve, $P(q,X) = P(\sum_i x_iq_i)$. Letting the inverse demand curve faced by each facility vary allows for transportation costs between spatially differentiated facilities or production of differentiated goods.

[7] I denote the cost of an outage as $c_p(0)$, the cost of planned production equal to zero. Functional form assumptions on outage costs do not affect the incentive conclusions.

an increase in output on expected profits arising from a change in facility reliability. If output has no effect on reliability, that is if $\frac{\partial \lambda_i}{\partial q_i} = 0$, no indirect effect exists, and the FOC for q_i reduces to the standard FOC for a firm choosing quantity. In choosing m_i, the maintenance levels at the facility, the firm weighs the marginal increase in expected profits associated with an increase in maintenance investment and hence reliability against the marginal cost of increasing maintenance. If maintenance does not affect facility reliability, the FOC for maintenance reduces to $c_m' = 0$ satisfied at $m_i = 0$ by restrictions placed on the first and second derivatives of c_m.[8]

I now consider the case where two of the N facilities are owned by a single firm. Specifically, I consider the maximization problem faced by a firm owning two facilities i and j, competing against $N-2$ independent firms each owning a single facility. The firm now chooses q_i, q_j, m_i and m_j so as to maximize the expected joint profits of facilities i and j. Let $E_X[\Pi_H] = E_X[\Pi_i] + E_X[\Pi_j]$ denote the profits of the horizontally integrated firm, the joint profits of facilities i and j.

Consider the choice of output and maintenance for facility i. Conditioning on the realization of the Bernoulli variables for facility i and j, $E_X[\Pi_H]$ can be separated into the sum of four conditional expectations corresponding to the joint realization of (x_i, x_j). Expressing $E_X[\Pi_H]$ as a conditional expectation of the four possible realizations of (x_i, x_j), and grouping terms,

$$\begin{aligned} E_X[\Pi_H] &= \lambda_i\lambda_j(q_iE_X[P_i(q,X)|x_i,x_j=1] + q_jE_X[P_j(q,X)|x_i,x_j=1]) \\ &\quad +\lambda_i(1-\lambda_j)q_iE_X[P(q,X)|x_i=1,x_j=0] \\ &\quad +\lambda_j(1-\lambda_i)q_jE_X[P(q,X)|x_i=0,x_j=1] - c_m(m_i) - c_m(m_j) \\ &\quad -\lambda_ic_p(q_i) - (1-\lambda_i)c_p(0) - \lambda_jc_p(q_j) - (1-\lambda_j)c_p(0). \end{aligned}$$

Let $\frac{\partial E_X[\Pi_U]}{\partial q_i}$ denote the first order condition for output of facility i if it were owned

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[8] Second-derivative assumptions on cost of production, cost of maintenance and reliability ensure $q_i^*(q_{-i}, m_{-i}, m_i)$ and $m_i^*(q_{-i}, m_{-i}, q_i)$ are functions and not correspondences. It is important to note that for a given facility, more than choice of (m_i, q_i) given (m_{-i}, q_{-i}) may jointly solve the FOCs. For this paper, I do not consider actual choice of equilibria, but simply evaluate changes in incentives in the choice of (m_i, q_i) at a given equilibrium depending on whether or not facility i is affiliated with another refinery.

by an unintegrated firm. Taking the partial derivative of $E_X[\Pi_H]$ with respect to q_i, we have the first order condition for q_i, given by

$$\begin{aligned}\frac{\partial E_X[\Pi_H]}{\partial q_i} &= \frac{\partial E_X[\Pi_U]}{\partial q_i} + \lambda_i \lambda_j q_j \frac{\partial E_X[P_j(q,X)|x_i, x_j = 1]}{\partial q_i} \\ &\quad - \frac{\partial \lambda_i}{\partial q_i} \lambda_j q_j (E_X[P_j(q,X)|x_i = 0, x_j = 1] - E_X[P_j(q,X)|x_i, x_j = 1]) \\ &= 0.\end{aligned}$$

For a given (q_{-i}, m_{-i}, m_i), ownership of two facilities changes the optimal output of facility i. In addition to the terms for an unintegrated facility, two additional terms affect output choice of facility i . The first is the standard horizontal integration result, that facility i incorporates the effect of its choice of output on the expected profits of facility j. The sign on the term is negative implying that, by itself, internalization of the effect on the profits of facility j would lead facility i to choose output below the output level chosen in the unintegrated case. The second term captures the indirect effect on the profits of facility j. If a change in the output of facility i affects the reliability of facility i, a firm maximizing the joint profits of i and j will internalize this effect. For general $\frac{\partial \lambda_i}{\partial q_i} < 0$, the effect of integration has an ambiguous result on output relative to the unintegrated case.[9]

Considering the choice of m_i, let$\frac{\partial E_X[\Pi_U]}{\partial m_i}$ denote the first order condition for maintenance of facility i if it were owned by an unintegrated firm. The first-order condition for the choice of maintenance at facility i is given by

$$\begin{aligned}\frac{\partial E_X[\Pi_H]}{\partial m_i} &= \frac{\partial E_X[\Pi_U]}{\partial m_i} - \frac{\partial \lambda_i}{\partial m_i} \lambda_j q_j E_X[P_j(q,X)|x_i = 0, x_j = 1] \\ &\quad + \frac{\partial \lambda_i}{\partial m_i} \lambda_j q_j E_X[P_j(q,X)|x_i, x_j = 1] \\ &= 0.\end{aligned}$$

In the case of maintenance, the only effect internalized in a firm owning facilities

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[9] Under a linear demand curve, the sign of the effect on output choice of an integrated facility relative to the unintegrated facility is given by the sign of $-\lambda_i - \frac{\lambda_i}{q_i} q_i$. From the assumption that $\frac{\partial \lambda_1}{\partial q_i} \geq 0$, and increase in production relative to the unintegrated case implies a decrease in facility reliability. This condition relaxes for a convex demand curve, such as goods with production or transportation constraints such as electricity or petroleum.

i and j is the effect on the profits of facility j from an increase in reliability of facility i. Hence, we can unambiguously sign the effect of integration on the choice of maintenance - for given (q, m_{-i}), the profit maximizing choice of m_i weakly falls relative to the unintegrated case.[10]

Four testable predictions arise from the model. First, under certain functional form conditions, it is possible to sign the effect of horizontal integration on output and hence reliability. If output has no effect on reliability or an affiliated facility increases production relative to an unaffiliated facility, joint ownership will weakly decrease facility reliability. Second, the magnitude of the incentives depend on the degree to which production from a facility affects the price earned by an affiliated facility. Joint ownership of nearby facilities, where $E_X[P_j(q,X)|x_i = 0, x_j = 1] - E_X[P_j(q,X)|x_i, x_j = 1]$ is large, will have a greater effect on reliability than those selling into unrelated markets.[11] This prediction is similar to the third and fourth predictions of the model, that joint ownership of facilities will have a greater effect on reliability in markets or at times in which an outage has a larger effect on prices. Incentives from affiliation will be greater in markets in which a facility outage has a large effect on prices. In the case of gasoline, incentives from affiliation will be greater for products with few substitutes, such as special gasoline blends, or in geographic markets with substantial transportation costs. Finally, if inventories fluctuate over time or transportation and capacity constraints are more binding in certain months, the model predicts that the incentives arising from horizontal integration will be greater in these months.

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[10] In this formulation, it is important to note that both choice variables, output and maintenance, are strategic substitutes.

[11] In this paper, differentiation of facilities arise from transportation costs between geographic markets. This prediction, though, has a clear analog for differentiated products. Joint ownership of facilities producing close substitutes create stronger distortions away from decisions made by unaffiliated facilities.

3.4 Data Sources and Descriptive Statistics

I collect two sets of data to study the extent to which incentives help to explain refinery fires and explosions: (i) news or regulatory reports of refinery incidents, and (ii) a comprehensive dataset of refinery production capacity, ownership and geography.

From January 1995 through June 2002, I identify 120 unanticipated incidents occurring at refineries. The incidents include fires, explosions, lightning strikes and other events which may be related to facility operation. The incidents are plausibly unanticipated and, in contrast with unplanned outages at power plants, are verifiable. Events which are both unanticipated and verifiable reduce concerns that events are misreported by firms as a way to withhold output strategically. I identify incidents by searching local, regional and national news sources, filings by the US Chemical Safety Board, filings by publicly-traded refining companies to the SEC, and reports from the Acusafe Incident Database. Table 3.1 contains a list of the identified incidents I use as part of the econometric analyses which follow. While refinery incidents vary in magnitude dramatically, from large fires and explosions which require repairs to much smaller incidents which do not affect production, I do not explicitly differentiate fires and explosions based on magnitude for purposes of this analysis.[12]

I also construct a dataset of refinery-level characteristics for domestic refineries from January 1995 to December 2001. I collect data on refinery location and capacity of production units at each refinery from issues of the Energy Information Administration (EIA) Annual Refinery Report. Following my methodology in Chapter Two, I construct an estimate of the light-product production capacity at each refinery based on the capacity of various production units at each refinery.[13] The EIA also tracks

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[12] Approximately half of the incidents required documented repairs and reduced production capacity. It is this subset of incidents which I use to investigate the effect of supply shocks on gasoline markets in Chapter 2.

[13] Light product production capacity is defined as the sum of gasoline, jet fuel and diesel fuel production. I approximate light product capacity by forty percent of distillation capacity plus the sum of hydrocracking, thermal cracking and catalytic cracking capacity. This provides a better approximation of actual refinery production capacity of high-quality products than simple distillation capacity.

changes in ownership within the refining industry in the Petroleum Supply Monthly. Combining changes in refinery ownership with production capacity at each refinery allows me to track, on a monthly basis, the production capacity at each refinery and also production capacity of all other assets owned by the same refiner.

Table 3.2 provides the summary statistics of refinery characteristics based on the population of monthly observations at all 173 domestic refineries open at some point during from January 1995 to December 2001. Mean light product capacity at domestic refineries is 3.98 million gallons per day, substantially greater than median refinery capacity of 2.25 million gallons per day. Average total production capacity summed across all refineries is 613 million gallons per day.

As indicated by the summary statistics, incidents at refineries are relatively rare. The probability of an unplanned incident at a given refinery in a given month is 0.9 percent with 0.7 incidents occurring on average at each facility over the seven-year period. During the study period, unanticipated incidents occurred at 65 of the 173 domestic refineries with more than one incident occurring at 34 refineries. Separating the sample by quartiles based on production capacity, I find that the average number of incidents at refineries is positively correlated with the production capacity of the refinery. Of the 120 incidents identified four incidents occurred at refineries in the lowest quartile of the production capacity distribution, fourteen incidents occurred at refineries in the second quartile, thirty-three incidents occurred at refineries in the third quartile and sixty-nine incidents occurred at refineries in the upper quartile. Geographically by Petroleum Area Defense Districts (PADDs), statistically more incidents occurred at refineries in PADD 1 (East Coast) and PADD 2 (Midwest) than at refineries in other areas.

Aggregating across refineries, 1.3 unplanned outages occur on average in each month. Like the distribution of incidents across refineries, substantial variation exists in the number of incidents from month to month. Incidents occurred in fifty-one of the eighty-four months in the study period - in months with an incident, the number of incidents varied from one or two in many months to six incidents in July 2001. Figure 3.1 graphs the number of unanticipated incidents I identify by month and year. Of the 120 incidents identified, 102 were fires or explosions at refineries. Of the remaining 18 incidents: seven were caused by lightning, three by complications associated with planned maintenance, three were chemicals releases, three were power outages and two were described only as "unplanned" maintenance. Figure 3.2 graphs the incidents identified in the data by the type of incident and the month of occurrence for incidents from January 1995 through December 2001.[14] Incidents exhibit substantial seasonality - although fires and explosions make up the majority of incidents, they are more prevalent in the summer. In addition, six of the seven incidents involving lightning occurred in May, June or July.

3.5 Econometric Model and Results

I specify a reduced-form model to estimate the correlation between ownership of multiple refining assets and the probability of an unplanned refinery outage at a given refinery. The goal is to test if the pattern of incidents at refineries is consistent with the predictions of the theoretical model. The probability of an outage at refinery i in month t, is given by

$$Prob(Y_{it} = 1) = f(\beta X_{it}) + \epsilon_{it}$$

where X_{it} denotes a vector of variables related to the capacity factors of other facilities owned by the refinery owning refiner i, and Y_{it} is a discrete variable equal to one if an incident occurs at refinery i and time t and $E(\epsilon_{it}|X_{it}) = 0$.

I use a standard probit specification where

$$E(Y_{it}|X_{it}) = \int_{-\infty}^{\beta X_{it}} \frac{e^{-\frac{x^2}{2}}}{\sqrt{2\Pi}} dx.$$

For the initial regressions, summarized in Tables 3.3 and 3.4, I include several sets of variables to test whether the pattern of incidents at refineries during the study period is consistent with the second, third and fourth predictions of the theoretical

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[14] For Figure 3.2, I exclude identified events occurring from January 2002 to July 2002, so that each month is represented equally.

model. The second prediction of the theoretical model is that incentives arising from joint-ownership depend on the geographic proximity of affiliated refineries. I use separate geographic definitions to differentially treat refining capacity near and far from a given refinery. Differentiating by spatial proximity also allows me to rule out changes in facility reliability which might arise from global economies or diseconomies of scale in the provision of maintenance.

I construct two separate sets of proxies for incentives arising from joint ownership related to geographic proximity. The first set, used in the specifications in Table 3.3, is the sum of all other production capacity owned by the firm within state, outside of the state but within PADD (Petroleum Area Defense District) and outside of the PADD. For example, consider a refiner owning four refineries, A, B, C and D, where A and B are in the same state, and A, B and C are in the same PADD. For refinery A, the in-state variable is given by the capacity of refinery B, the out of state but within PADD proxy is given by the capacity of refinery C, and the out of PADD proxy is given by the capacity of refinery D. For the second set of proxy variables, used in Table 3.4, I normalize the three initial proxies by total production capacity for the relevant geographic region. Again considering the hypothetical refiner above, for refinery A, the percent of in-state refining capacity is the capacity of B divided by total refining capacity within state. The percent of refining capacity out-of-state but within PADD is the capacity of refinery C normalized by total refining capacity out-of-state but within-PADD. Normalizing by total production capacity weights ownership in a particular region relative to total ownership within the region. By normalizing in such a way, I better capture incentives arising from joint ownership since owning a small amount of additional capacity in a small market might create very similar incentives to owning a larger amount of capacity in a more competitive market. In either case, the model predicts ownership of two refineries in the same state should have a larger effect on operation than owning two refineries in the same PADD which would likewise have a larger effect on operation than owning two refineries in different PADDs.

The third prediction of the theoretical model states that operational incentives arising from joint-ownership are greater in markets in which an outage has a large effect on prices. Thus, I also include an interaction term of in-state refining capacity with a dummy variable corresponding to months in which California, Chicago and Milwaukee use special blends of gasoline. As studied in Chapter Two, refinery outages have a larger effect on prices in markets with special content regulations, such as California, Illinois and Wisconsin. Thus, affiliation of capacity in markets with and without special regulations should have different incentive implications than similar affiliation in markets without special regulations.

The final prediction of the model is if demand varies over the course of the year, months in which an outage has a larger effect should also be months in which incentives to operate affiliated facilities are most different from incentives to operate unaffiliated facilities. Thus, in addition to the ownership variables described above, I include either seasonal or monthly dummy variables, allowing outage probability to vary over the course of the year. Gasoline demand and prices rise during the summer "driving" season. A finding that unplanned incidents are more prevalent in the summer is consistent with the implications of the theoretical model. If output is related to incident probability or if the incentives for output and maintenance vary in high and low demand periods, a prediction that incidents are more likely in the summer might provide some anecdotal support of the theoretical model. Before using seasonality as indirect evidence, though, I account for incidents with a seasonal component unrelated to operation or maintenance of a facility. In particular, incidents related to lightning may potentially bias seasonal coefficients in favor of the implications of the theoretical model - lightning is both plausibly exogenous to operation or maintenance, as well as strongly seasonal.[15] To avoid biasing the coefficients on seasonal or monthly dummy variables in a way consistent with the implications of the theoretical model, I exclude lightning-related incidents from the probit regression. I also exclude the three incidents related to planned maintenance and two incidents described simply as "unplanned outages". Based on my research, I was not able to verify that

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[15] Of the seven lightning-related incidents in the data, three incidents occurred in June, two in May and one in July.

the "unplanned outages" were in fact unanticipated and, thus, unrelated to explicit strategic behavior. Of the 110 incidents in my data occurring between January 1995 and December 2001, I use 95 fires, explosions, chemical releases and power outages.[16]

Table 3.3 contains estimated coefficients based on the probit regression of the occurrence of an incident at refinery i in month j on the first proxy for ownership incentives, seasonal or monthly fixed-effects, and capacity of refinery i. The first specification excludes the capacity variable. Specifications (1) and (2) include refinery capacity as well as seasonal and monthly fixed-effects. Specification (3) and (4) add a cross-term of instate refining capacity and a California, Illinois or Wisconsin location dummy variable.

The point estimates for coefficients are roughly consistent with several of the predictions of the theoretical model: (i) Incentives arising from ownership of two refineries in closely related geographic markets are stronger than incentives from joint-ownership of refineries in distant geographic markets, (ii)Incentives arising from joint-ownership are greatest for products for which incidents have the greatest effect on prices, and (iii) Incentives arising from joint-ownership are stronger in months in which an outage has a larger effect on market prices . In specifications (1) and (2), the point estimate of the coefficient on in-state refining capacity are positive and greater than that of out-of-state, within-PADD refining capacity as well as out-of-PADD refining capacity, although all three point estimates are imprecisely estimated. Moreover, in specification (3) and (4), the point estimate of the coefficient on the cross term of instate refining capacity and the CA, IL and WI dummy variable is also positive and of greater magnitude than the coefficient on instate refining capacity. Although again, the coefficient is imprecisely estimated, the relative size of the two terms is consistent with the predictions from the theoretical model - controlling for refinery size, the probability of an outage at a facility owned by a refiner with nearby refineries is greater than that at a facility owned by a refiner with no proximate refining assets.

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[16] I test the robustness of my results to inclusion or exclusion of these other types of incidents and find that changing the sample of incidents does not have a substantively change my results.

The coefficients on the seasonal and monthly dummy variables are robust across the different specifications. The coefficient on summer is positive and significant, as well as statistically greater than the coefficients on spring and fall. While the point estimates on the monthly coefficients are imprecisely estimated, they follow a similar pattern - the expectation of refinery fires or explosions rises in the summer months and falls in winter months.[17]

Table 3.4 presents the estimated coefficients for the normalized proxies for joint ownership incentives, temporal fixed-effects and refinery capacity. Specifications (1) through (4) in Table 3.4 replicate the specifications in Table 3.3. In each, I regress incident occurrence on refinery capacity, the second set of ownership proxies, and seasonal or monthly fixed-effects. The econometric results are similar to those in Table 3.3. The coefficient on capacity is again positive and highly significant. The likelihood of a fire or explosion exhibits seasonality - fires and explosions are more likely in the summer than the winter. In addition, the coefficients on the proxies for incentives arising from joint ownership are consistent with the predictions of the theoretical model - other refining capacity owned in-state has a larger effect on the probability of an outage than refining capacity outside the state but within the PADD. In specifications (3) and (4), when I include the cross term of in-state refining capacity and the dummy variable for specialized local gasoline formulation, the point estimate for the cross-term coefficient is of greater magnitude than the coefficient on in-state refining capacity alone.[18]

Table 3.5 presents the results from Table 3.4 specification (3) as probabilities rather than coefficients from the probit estimation. The point estimates imply that at the median refinery the expected probability of a fire or explosion in the winter is 0.41 percent and the expected probability of a fire or explosion in the summer is 0.92 percent. Table 3.5 also presents the expected probability of an incident for the

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[17] I classify spring as March through May, summer as June through August, and fall as September through November.

[18] All of the results in Tables 3.3 and 3.4 are robust to estimation based on subsamples (1) excluding refineries with capacities in the lowest quartile (capacity less than 567 thousand gallons per day) and (2) excluding refineries closed for more than one quarter of the study period.

median refinery conditional on ownership. The point estimates imply that a refinery of mean capacity unaffiliated with other refining assets has a 0.88 percent expected incident probability during a summer month. The expected probability of a refinery of mean capacity owned by a refiner owning 3.4 percent of other in-state capacity, 3.9 percent of other in-PADD capacity and 2.9 percent of other out-of-PADD capacity is only slightly higher, at 0.93 percent.[19] If the refinery is located, though, in either California or Illinois, the expected incident probability of an affiliated refinery is 1.15 percent - approximately 31 percent higher than the expected incident probability of an unaffiliated refinery.

Two concerns exist with the approach above. The first is that, although I control for refinery size, omitted variables affecting facility reliability might exist which are correlated with ownership - biasing the coefficients on ownership. Alternatively, it could also be the case that refiners choose their porfolio of refineries based partially on facility-specific incident likelihoods. That is, a refiner owning another facility in an area is willing to pay a higher price for a refinery with a high probability of a fire than a refiner without another facility in the area. The correlation I identify in Tables 3.3 and 3.4, thus, may not be the result of operational incentives, but may be an artifact of a refiner's selection of her portfolio of refining assets.

Thus, I also test probit specifications in which each refinery's outage probability is a function of ownership incentives as well as refinery-specific unobservables, captured with refinery-level fixed effects. In this specification, identification of the effect of changing ownership incentives comes from within-refinery variation in ownership over time. That is, I identify the effect of changes in refinery ownership from the expectation function conditional on refinery and ownership. I estimate the specification with refinery-specific dummy variables to allow the probability of a refinery fire or explosion to vary systematically by facility. Although allowing refinery-specific dummy variables better models persistent refinery differences related to probability of fire or explosion, the use of refinery-specific dummy variables constrains my

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[19] For calculating the estimated incident probability based on ownership, I assume ownership characteristics for affiliation with the mean affiliated refiner.

sample to only those facility which experienced an outage over the sample period.[20] This specification estimates the coefficients of the joint ownership proxies based on the within-refinery changes at only the sixty refineries which experienced a fire or explosion from January 1995 through December 2001.

Table 3.6 contains the estimated probit coefficients allowing for refinery-level fixed effects. Specifications (1) through (4) replicate specifications in Table 3.4, with the exception of omitting the capacity variable. Including refinery fixed effects and limiting the sample to the subset of refineries experiencing a fire or explosion affects the point estimates and precision of the estimated coefficients. Refinery-level fixed effects remove much of the variation used to identify the coefficients in the earlier specifications. As a result, no coefficients on the proxies for ownership are estimated with precision. Although the point estimate for the cross-term included in specifications (3) and (4) is of the same sign and magnitude as the corresponding point estimates in Table 3.4, the signs and magnitudes of the other proxy coefficients vary. The point estimates of the coefficients on the seasonal or monthly dummy variables, though, are robust to limiting the sample to the subset of firms with one or more fires or explosions over the period. Although the results from the Tables 3.3 and 3.4 are consistent with the theoretical model, the results in Table 3.6 do not allow me to reject the possibility that my earlier results are the result either of omitted variable bias or endogenous portfolio selection by refiners.

3.6 Conclusion

Regulators studying high prices in a market often face the challenge of differentiating strategic withholding by producers from unreliable production. If a regulator cannot verify "unplanned" outages, the regulator cannot credibly distinguish between strategic withholding and unlucky realizations of facility reliability. In this paper, I specify a model in which a firm's choices of production and maintenance affect facility

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[20] The conditional expectation for a facility for which no incident occurred over the study period, is trivially identified by the refinery-specific dummy variable.

reliability. I study how incentives arising from ownership of more than one facility affect facility reliability. Under derived functional form restrictions on demand, my model provides an alternative to strategic withholding as an explanation as to why a correlation may exist between benefits to a firm from unanticipated facility outages in a market and the reliability of facilities owned by that firm. Intuitively, if facility outages affect prices in a market, firms owning more than one facility will have different operational and maintenance incentives than firms owning a single facility in a market. Differences in incentives for firms owning more than one facility depend on demand conditions - in months or markets in which price respond more to facility outages, operation of affiliated facilities differ relative to operation of unaffiliated facilities.

I collect a dataset of unanticipated and verifiable incidents, including fires, explosions and other unplanned events, at domestic oil refineries from January 1995 through December 2001. I then test whether the pattern of incidents is consistent with the predictions of the theoretical model. I find statistically significant evidence that ownership of other local refining capacity is correlated with the probability of an outage at a given refinery. In addition, the relationship between ownership and incident likelihood is greatest for markets with special gasoline formulations. It is in markets with special content regulations that a refinery outage has the largest effect of gasoline prices. In these markets, expected incident likelihood is 30 percent greater for a refinery affiliated with another refinery that it is for an unaffiliated refinery. I find that although the evidence is consistent with the model, I am unable to statistically rule out the alternative hypothesis that firms select refineries based on refinery-specific outage probabilities - that is, refinery outages are less costly for a firm with multiple refineries, as a result, theory predicts these firms would be willing to pay more than firms without other refineries for unreliable assets.

Regardless of the source of the correlation, this research has several implications for merger and regulatory policy. First, this paper proposes an important source of unanticipated outages, which could be correlated with the incentives of a firm to strategically withhold output in a market. This result complicates the job of the regulator - it is not sufficient to assess the incentives for strategic withholding as evidence for explicit withholding by a firm. In addition, the theoretical model defines market conditions under which it is reasonable to expect operation and maintenance of affiliated firms to differ substantially from unaffiliated firms. To the extent that price volatility concerns regulators (or legislators directing regulatory activity), the model identifies characteristics of markets for which reliability concerns may be greatest. Finally, refinery fires and explosions create price volatility in local gasoline markets. This paper also provides descriptive statistics on incident frequency at refineries, potentially useful to gasoline regulation policy makers.

Table 3.1: Identified Refinery Incidents
January 1995 - December 2001

Refinery	State	Refiner	Outage Date	Outage Nature	Information Source
Meraux	Louisiana	Murphy Oil	6-Jun-02	Fire at operating unit.	D
Anacortes	Washington	Tesoro	9-Mar-02	Explosion at deasphalting plant.	D
Salt Lake City	Utah	Tesoro	24-Feb-02	Fire following power outage.	B
Delaware City	Delaware	Motiva	22-Jan-02	Fire at hydrotreater.	D
El Segundo	California	Chevron	20-Jan-02	Explosion	B
Baton Rouge	Louisiana	ExxonMobil	13-Jan-02	Fire	D
Pasadena	Texas	Crown Central Petro Group	13-Jan-02	Fire at alkylation unit.	D
Superior	Wisconsin	Murphy Oil	7-Jan-02	Fire and explosion at gasoline storage tank.	B
Cheyenne	Wyoming	Frontier Refining	19-Dec-01	Explosion at hydrogen compressor.	A, B
Benecia	California	Valero	29-Nov-01	Explosion at asphalting unit	B
Mount Vernon	Indiana	Country Mark	25-Nov-01	Fire in naphtha unit.	B
Pasadena	Texas	Crown Central Petro Group	23-Nov-01	Explosion	D
Lake Charles	Louisiana	Citgo	21-Sep-01	Explosion and fire at hydrocracking unit.	A, D
Westville	New Jersey	Coastal Corp	8-Sep-01	Fire at distillation unit.	B
Ponca City	Oklahoma	Conoco	16-Aug-01	Removal of Cat Cracker from service.	A
Lemont	Illinois	PDV America/Citgo	14-Aug-01	Fire at distillation unit.	B
Deer Park	Texas	Deer Park Ltd	8-Aug-01	Fire	A
Yorktown	Virginia	BP	27-Jul-01	Fire at disillation unit.	B
Martinez	California	Shell	18-Jul-01	Fire	D
Delaware City	Delaware	Motiva	17-Jul-01	Fire and acid spill.	D
Deer Park	Texas	deer park ltd	14-Jul-01	Fire at coker.	A
Three Rivers	Texas	Ultramar Diamond Shamrock	9-Jul-01	Fire and explosion at alkylation unit.	A, D
Port Arthur	Texas	Blackstone Group	1-May-01	Lightning Strike	A
Woods Cross	Utah	Inland	4-Jul-01	Fire	A
Philadelphia	Pennsylvania	Sunoco	30-Jun-01	Fire at reformer.	D
Norco	Louisiana	Orion	7-Jun-01	Lightning Strike	A, B
Yorktown	Virginia	BP	6-Jun-01	Fire at reformer.	A, B
Los Angeles	California	BP	26-May-01	Fire at cracking unit	B
Tuscoloosa	Alabama	Hunt Refining	13-May-01	Fire and Explosion.	A, B
Wood River	Illinois	Tosco	28-Apr-01	Fire at distillation unit.	A, B
Wilmington	California	Tosco	23-Apr-01	Fire at coker.	A, D
Benicia	California	ExxonMobil	1-Mar-01	Delayed restart.	A
Chalmette	Louisiana	Chalmette Rfg.	19-Jan-01	Fire.	A
Blue Island	Illinois	Clark	1-Jan-01	Upgrades.	A
Philadelphia	Pennsylvania	Sunoco	23-Dec-00	Fire.	A
Westville	New Jersey	Coastal Corp	8-Sep-00	Fire at dewaxer.	A
Philadelphia	Pennsylvania	Sunoco	7-Sep-00	Fire at distillation unit.	B, D
Marcus Hook	Pennsylvania	Sunoco	30-Aug-00	Fire at Cat Cracker.	D
Convent	Louisiana	Motiva	18-Aug-00	Explosion at Hydro Cracker	D
Robinson	Illinois	Marathon Ashland	5-Aug-00	Fire at Reformer and Hydro Cracker	D
Philadelphia	Pennsylvania	Sunoco	30-Jun-00	Explosion.	D
Philadelphia	Pennsylvania	Sunoco	21-Jun-00	Release of Catalyst	D
Norco	Louisiana	Orion	10-Jun-00	Explosion.	A
Avon	California	Tosco	7-Jun-00	Fire at coker.	A
Port Arthur	Texas	Blackstone Group	25-May-00	Fire at distillation unit.	C
Salt Lake City	Utah	BP Amoco	4-Apr-00	Fire at reformer.	A
North Salt Lake	Utah	Flying J	17-Mar-00	Explosion.	B
Westville	New Jersey	Coastal Corp	1-Mar-00	Fire.	A
Whiting	Indiana	BP	1-Mar-00	Fire at distillation unit.	A
Baton Rouge	Louisiana	Exxon Mobil	23-Feb-00	Fire.	A
Blue Island	Illinois	Clark	29-Jan-00	Fire at Cat Cracker.	B
Shreveport	Louisiana	Pennzoil	18-Jan-00	Explosion.	A, B
Blue Island	Illinois	Clark	24-Dec-99	Explosion.	B
Ponca City	Oklahoma	Conoco	28-Nov-99	Fire and Explosion at Storage Tank	A, B
Great Falls	Montana	Holly Corp	19-Nov-99	Fire.	A
Chalmette	Louisiana	Chalmette Rfg.	17-Nov-99	Fire at coker.	B
Wilmington	California	Tosco	9-Nov-99	Fire at oil tank.	A, B
Memphis	Tennessee	Williams	26-Oct-99	Chemical release.	B
Toledo	Ohio	Sunoco	28-Aug-99	Explosion at distillation unit.	A, B
Tuscoloosa	Alabama	Hunt Refining	18-Aug-99	Fire.	A
Convent	Louisiana	Motiva	13-Aug-99	Fire.	A
Shreveport	Louisiana	Pennzoil	13-Aug-99	Fire at storage tank.	A
Corpus Christi	Texas	Citgo	9-Aug-99	Explosion at boiler.	A, B
Torrance	California	Mobil	28-Jul-99	Fire at Hydrogen Facility.	A
Richmond	California	Chevron	10-Jul-99	Fire.	A, C
Philadelphia	Pennsylvania	Sunoco	21-Jun-99	Fire at hydrotreater.	A

Table 3.1: Identified Refinery Incidents (continued)
January 1995 - December 2001

Refinery	State	Refiner	Outage Date	Outage Nature	Information Source
Memphis	Tennessee	Williams	16-Jun-99	Fire at Cat Cracker.	A
Corpus Christi	Texas	Coastal Corp	14-May-99	Fire at reformer.	A
Houston	Texas	Lyondell	7-May-99	Fire and explosion at coker.	A
Tulsa	Oklahoma	Sunoco	27-Apr-99	Fire at coker.	A
Whiting	Indiana	BP	20-Apr-99	Explosion at Cat Cracker.	A
Los Angeles	California	Arco	27-Mar-99	Cogen Plant Failure.	A
Richmond	California	Chevron	26-Mar-99	Fire at Hydro Cracker.	A, C
Avon	California	Tosco	23-Feb-99	Fire at disillation unit.	B
Lemont	Illinois	Citgo	23-Feb-99	Fire at distillation unit.	A
toledo	Ohio	BP	9-Feb-99	Fire.	A
Smackover	Arkansas	Cross Petrol	13-Jan-99	Explosion at tank.	A
Trainer	Pennsylvania	Tosco	15-Dec-98	Fire at pipeline.	A
Anacortes	Washington	Equilon	13-Dec-98	Fire at coker.	A
Mandan	North Dakota	Amoco	24-Oct-98	Fire at distillation unit.	A
Laurel	Montana	Cenex	19-Oct-98	Fire at pipeline.	A
Trainer	Pennsylvania	Tosco	16-Oct-98	Explosion at Storage Tank.	B
Los Angeles	California	Arco	8-Oct-98	Fire.	A
Belle Chasse	Louisiana	BP	2-Oct-98	Fire.	A
Avon	California	Tosco	25-Aug-98	Fire.	A
Avon	California	Tosco	30-Jul-98	Fire.	A, C
Ardmore	Oklahoma	Ultramar Diamond Shamrock	13-Jul-98	Fire at distillation unit.	B, C
Philadelphia	Pennsylvania	Sunoco	26-Jun-98	Power Outage and Shutdown of Cat Cracker.	C
Convent	Louisiana	Star	13-Apr-98	Fire.	A
Deer Park	Texas	Shell	13-Jul-97	Fire at coker.	A
Deer Park	Texas	Shell	22-Jun-97	Fire at Olefin Processing Unit.	D
Catlettsburg	Kentucky	Ashland Oil	7-Jun-97	Explosion at Reformer.	A
St Paul Park	Minnesota	Ashland Oil	16-May-97	Explosion.	A
Corpus Christi	Texas	Citgo	14-May-97	Explosion at Alkylation Unit.	A, C
Avon	California	Tosco	22-Jan-97	Explosion at Hydro Cracker	A, C
Chalmette	Louisiana	Mobil	22-Jan-97	Fire.	A
Wilmington	California	Texaco	13-Jan-97	Fire at alkylation unit.	A
Bayway	New Jersey	Tosco	1-Jan-97	Unscheduled Shutdown of Cat Cracker.	C
Torrance	California	Mobil	21-Nov-96	Fire.	A
Wilmington	California	Texaco	11-Nov-96	Explosion at Hydrotreater.	A
Blue Island	Illinois	clark oil	19-Oct-96	Propane Fire.	A, C
Norco	Louisiana	Shell	15-Oct-96	Fire.	A
toledo	Ohio	BP	15-Oct-96	Fire at distillation unit.	A
Ponca City	Oklahoma	Conoco	10-Jul-96	Fire at hydrotreater.	A
Linden	New Jersey	Tosco	12-Jun-96	Fire.	A
Mandan	North Dakota	Amoco	11-Jun-96	Vapor emission.	A
Pine Bend	Minnesota	Koch	21-May-96	Lightning Strike	A
Rodeo	California	Unocal	17-May-96	Fire at coker.	A
Martinez	California	Shell	1-Apr-96	Explosion at Hydrotreater.	A
Commerce City	Colorado	TPI	5-Feb-96	Fire.	A
Martinez	California	Shell	2-Feb-96	Explosion at Hydrogen unit.	A
Baytown	Texas	Exxon	16-Nov-95	Explosion at Hydrotreater.	A
Rouseville	Pennsylvania	Pennzoil	17-Oct-95	Explosion	A
Meraux	Louisiana	Murphy Oil	28-Jul-95	Explosion	A
Texas City	Texas	Amoco	25-Jul-95	Fire at Cat Cracker.	A
El Dorado	Arkansas	Lion Oil	22-Jul-95	Fire at storage tank.	A
Catlettsburg	Kentucky	Ashland Oil	27-Jun-95	Fire at storage tank.	A
Memphis	Tennessee	Mapco	20-Jun-95	Fire.	A
Chalmette	Louisiana	Mobil	27-Apr-95	Fire at distillation unit.	A
Blue Island	Illinois	Clark Oil	14-Mar-95	Explosion and fire.	A

Source:
A - Local or Regional News Source
B - US Chemical Safety Board Filing
C - SEC Filing
D - Acusafe Monthly Incident Reports

Table 3.2:
Descriptive Statistics

	Moments		Quartiles				
Variable	Mean	SD	Min	25%	50%	75%	Max
Refinery-Specific Variables							
Incident Dummy	0.009	0.092	0	0	0	0	1
Refinery Light Product Capacity (mmgal/day)	3.99	4.27	0.13	0.57	2.25	6.12	21.21
Refinery-Specific Ownership Variables							
Other In-state Refiner Capacity	1.25	3.03	0.00	0.00	0.00	0.14	20.75
Own-Capacity Out of State but Within PADD	2.74	5.37	0.00	0.00	0.00	2.68	35.74
Own-Capacity Outside of PADD	9.37	13.42	0.00	0.11	6.69	21.98	79.35
Percent In-state Refinery Capacity	0.026	0.071	0.00	0.00	0.00	0.00	0.51
Percent Out-of-State Within Padd Refinery Capacity	0.030	0.056	0.00	0.00	0.00	0.04	0.32
Percent Out-of-PADD Refinery Capacity	0.022	0.026	0.00	0.00	0.01	0.04	0.12
Count of Owned In-State Refineries	0.33	0.61	0	0	0	1	4
Count of Owned In-PADD Refineries	0.82	1.02	0	0	1	1	5
Count of Owned Refineries	2.39	2.20	0	1	2	4	12
System-wide Capacity (mmgal/day)							
Total In-State Refining Capacity	59.33	59.82	0.07	6.31	23.55	97.07	178.41
Total In-PADD Refining Capacity	167.95	100.14	18.75	110.32	133.72	280.61	311.69
Total Domestic Refining Capacity	612.92	23.12	582.60	595.76	599.91	639.75	652.00
Total Outages							
Count of Outages By Month	1.33	1.42	0	0	1	2	7
Count of Outages By Refinery	0.71	1.16	0	0	0	1	7

Note: Units for Capacity figures are millions of gallons of light product capacity per day.
Refiner-Specific Ownership for Refinery i includes All Refineries Owned by

N =12920 for Refinery-Specific Variables
=182 for Count of Outages by Refinery (aggregated by Month)
=84 for Count of Outages By Month (aggregated by Refinery)

Table 3.3:
Estimated Coefficients from Probit Regression
Dependent Variable: Refinery Incident Dummy

	Specification			
Variables	**(1)**	**(2)'**	**(3)**	**(4)**
Constant	**-2.820*****	**-2.771*****	**-2.821*****	**-2.771*****
	0.099	0.156	0.099	0.157
Refinery Capacity	**0.041*****	**0.041*****	**0.042*****	**0.043*****
	0.008	0.008	0.008	0.008
In-State Refining Capacity*CA/IL Dummy			**0.030***	**0.030***
			0.017	0.017
In-State Refining Capacity	**0.015***	**0.016***	**0.000**	**0.001**
	0.009	0.009	0.013	0.013
Out-of-State, In-PADD Refining Capacity	**-0.006**	**-0.006**	**-0.005**	**-0.005**
	0.007	0.007	0.007	0.007
Out-of-PADD Refining Capacity	**0.002**	**0.002**	**0.002**	**0.002**
	0.003	0.003	0.003	0.003
Spring	**0.076**		**0.073**	
	0.119		0.119	
Summer	**0.291*****		**0.291*****	
	0.108		0.108	
Fall	**0.131**		**0.131**	
	0.116		0.116	
February		**-0.018**		**-0.020**
		0.205		0.205
March		**-0.079**		**-0.084**
		0.214		0.214
April		**0.086**		**0.084**
		0.193		0.194
May		**0.051**		**0.048**
		0.201		0.201
June		**0.239**		**0.241**
		0.183		0.183
July		**0.270**		**0.266**
		0.181		0.181
August		**0.210**		**0.212**
		0.186		0.186
September		**-0.161**		**-0.160**
		0.224		0.224
October		**0.146**		**0.146**
		0.193		0.193
November		**0.180**		**0.178**
		0.189		0.189
December		**-0.150**		**-0.149**
		0.226		0.226
Facility Fixed Effects	None	None	None	None
Temporal Fixed Effects	Seasonal	Monthly	Seasonal	Monthly
Pseudo R-Squared	0.0387	0.0428	0.0411	0.0452
Log-likelyhood	-539.5	-537.2	-538.2	-535.9
N	12905	12905	12905	12905

Notes: Point estimates in bold type. Robust standard errors listed below.
*Denotes significance at the 10% level.
**Denotes significance at the 5% level.
***Denotes significance at the 1% level.

Table 3.4:
Estimated Coefficients from Probit Regression
Dependent Variable: Refinery Incident Dummy

	Specification			
Variables	**(1)**	**(2)**	**(3)**	**(4)**
Constant	**-2.829*****	**-2.779*****	**-2.831*****	**-2.780*****
	0.099	0.157	0.099	0.157
Refinery Capacity	**0.039*****	**0.039*****	**0.041*****	**0.041*****
	0.007	0.007	0.008	0.008
Percent of In-State Refining Capacity*CA/IL Dummy			**2.335****	**2.343****
			1.045	1.040
Percent of In-State Refining Capacity	**0.749***	**0.765****	**0.414**	**0.435**
	0.386	0.385	0.476	0.473
Percent of Out-of-State, In-PADD Refining Capacity	**0.331**	**0.322**	**0.095**	**0.084**
	0.709	0.702	0.743	0.735
Percent of Out-of-PADD Refining Capacity	**0.600**	**0.558**	**0.130**	**0.081**
	1.883	1.861	1.997	1.975
Spring	**0.080**		**0.077**	
	0.119		0.119	
Summer	**0.296*****		**0.294*****	
	0.108		0.109	
Fall	**0.134**		**0.133**	
	0.116		0.117	
February		**-0.021**		**-0.020**
		0.204		0.205
March		**-0.075**		**-0.084**
		0.214		0.214
April		**0.089**		**0.090**
		0.193		0.194
May		**0.051**		**0.049**
		0.201		0.201
June		**0.241**		**0.242**
		0.183		0.183
July		**0.277**		**0.271**
		0.181		0.182
August		**0.210**		**0.210**
		0.186		0.186
September		**-0.161**		**-0.160**
		0.224		0.224
October		**0.144**		**0.145**
		0.192		0.193
November		**0.183**		**0.181**
		0.189		0.189
December		**-0.152**		**-0.153**
		0.225		0.225
Facility Fixed Effects	None	None	None	None
Temporal Fixed Effects	Seasonal	Monthly	Seasonal	Monthly
Pseudo R-Squared	0.0384	0.0425	0.0421	0.0463
Log-likelyhood	-539.7	-537.4	-537.6	-535.3
N	12905	12905	12905	12905

Notes: Point estimates in bold type. Robust standard errors listed below.
*Denotes significance at the 10% level.
**Denotes significance at the 5% level.
***Denotes significance at the 1% level.

Table 3.5:
Estimated Probabilities from Probit Regression
Table 3.4 - Specification 3

	Variables Capacity (mmgal/day)	Percentage of In-state Capacity	Percentage of Out-of-State State but Within Padd	Percentage of Out-of-Padd Capacity	In-State Refining Capacity *CA/IL	Spring	Summer	Fall	Estimated Incident Probability
Estimated Relationship Between Incident Probability and Seasonality									
Mean Refinery Winter	3.99	2.6%	3.0%	2.2%	0.0%	0	0	0	**0.40%**
Mean Refinery Spring	3.99	2.6%	3.0%	2.2%	0.0%	1	0	0	**0.50%**
Mean Refinery Summer	3.99	2.6%	3.0%	2.2%	0.0%	0	1	0	**0.92%**
Mean Refinery Fall	3.99	2.6%	3.0%	2.2%	0.0%	0	0	1	**0.59%**
Median Refinery Winter	2.25	0.0%	0.0%	1.1%	0.0%	0	0	0	**0.31%**
Median Refinery Spring	2.25	0.0%	0.0%	1.1%	0.0%	1	0	0	**0.39%**
Median Refinery Summer	2.25	0.0%	0.0%	1.1%	0.0%	0	1	0	**0.73%**
Median Refinery Fall	2.25	0.0%	0.0%	1.1%	0.0%	0	0	1	**0.46%**
Estimated Relationship Between Incident Probability and Capacity									
Refinery 1st Quartile Capacity Winter	6.14	0.0%	0.0%	1.1%	0.0%	0	0	0	**0.50%**
Refinery Median Capacity Winter	2.25	0.0%	0.0%	1.1%	0.0%	0	0	0	**0.31%**
Refinery 3rd Quartile Capacity Winter	0.73	0.0%	0.0%	1.1%	0.0%	0	0	0	**0.26%**
Refinery 1st Quartile Capacity Summer	6.14	0.0%	0.0%	1.1%	0.0%	0	1	0	**1.12%**
Refinery Median Capacity Summer	2.25	0.0%	0.0%	1.1%	0.0%	0	1	0	**0.73%**
Refinery 3rd Quartile Capacity Summer	0.73	0.0%	0.0%	1.1%	0.0%	0	1	0	**0.61%**
Estimated Relationship Between Incident Probability and Ownership (1)									
Mean Refinery Unaffiliated Winter	3.99	0.0%	0.0%	0.0%	0.0%	0	0	0	**0.38%**
Mean Capacity Affiliated Winter	3.99	3.4%	3.9%	2.9%	0.0%	0	0	0	**0.41%**
Mean Capacity Mean Ownership Winter, California	3.99	3.4%	3.9%	2.9%	3.4%	0	0	0	**0.51%**
Mean Capacity Unowned Summer	3.99	0.0%	0.0%	0.0%	0.0%	0	1	0	**0.88%**
Mean Capacity Mean Ownership Summer	3.99	3.4%	3.9%	2.9%	0.0%	0	1	0	**0.93%**
Mean Capacity Mean Ownership Summer, California	3.99	3.4%	3.9%	2.9%	3.4%	0	1	0	**1.15%**

Note: (1) Affiliation assumed to be that of the mean affiliated refinery.

Table 3.6:
Estimated Coefficients from Probit Regression
Dependent Variable: Refinery Incident Dummy

	Specification			
Variables	(1)	(2)	(3)	(4)
Constant	**-2.420*****	**-2.373*****	**-2.340*****	**-2.288*****
	0.426	0.423	0.421	0.414
Percent of In-State Refining Capacity	**-1.843**	**-1.878**	**-2.882**	**-2.940**
	1.567	1.561	2.204	2.203
Percent of Out-of-State, In-PADD Refining Capacity	**-0.548**	**-0.538**	**-1.254**	**-1.253**
	2.142	2.125	2.177	2.162
Percent of Out-of-PADD Refining Capacity	**2.333**	**2.401**	**2.277**	**2.342**
	3.484	3.444	3.499	3.459
Percent of In-State Refining Capacity*CA/IL Dummy			**3.007**	**3.065**
			2.616	2.600
Spring	**0.111**		**0.109**	
	0.125		0.125	
Summer	**0.356*****		**0.351*****	
	0.115		0.115	
Fall	**0.178**		**0.176**	
	0.121		0.121	
February		**0.020**		**0.016**
		0.217		0.217
March		**-0.053**		**-0.058**
		0.226		0.226
April		**0.144**		**0.140**
		0.206		0.206
May		**0.110**		**0.103**
		0.209		0.209
June		**0.291**		**0.280**
		0.193		0.191
July		**0.374****		**0.366***
		0.193		0.192
August		**0.290**		**0.285**
		0.198		0.198
September		**-0.155**		**-0.161**
		0.233		0.232
October		**0.215**		**0.211**
		0.201		0.200
November		**0.269**		**0.262**
		0.200		0.200
December		**-0.148**		**-0.153**
		0.235		0.236
Facility Fixed Effects	Refinery-leve	Refinery-leve	Refinery-leve	Refinery-level
Temporal Fixed Effects	None	Seasonal	Monthly	Month-year
Pseudo R-Squared	0.0486	0.0543	0.0498	0.0556
Log-likelyhood	-440.3	-437.7	-439.8	-437.1
N	4610	4610	4610	4610

Figure 3.1:
Refinery Incidents Over Time

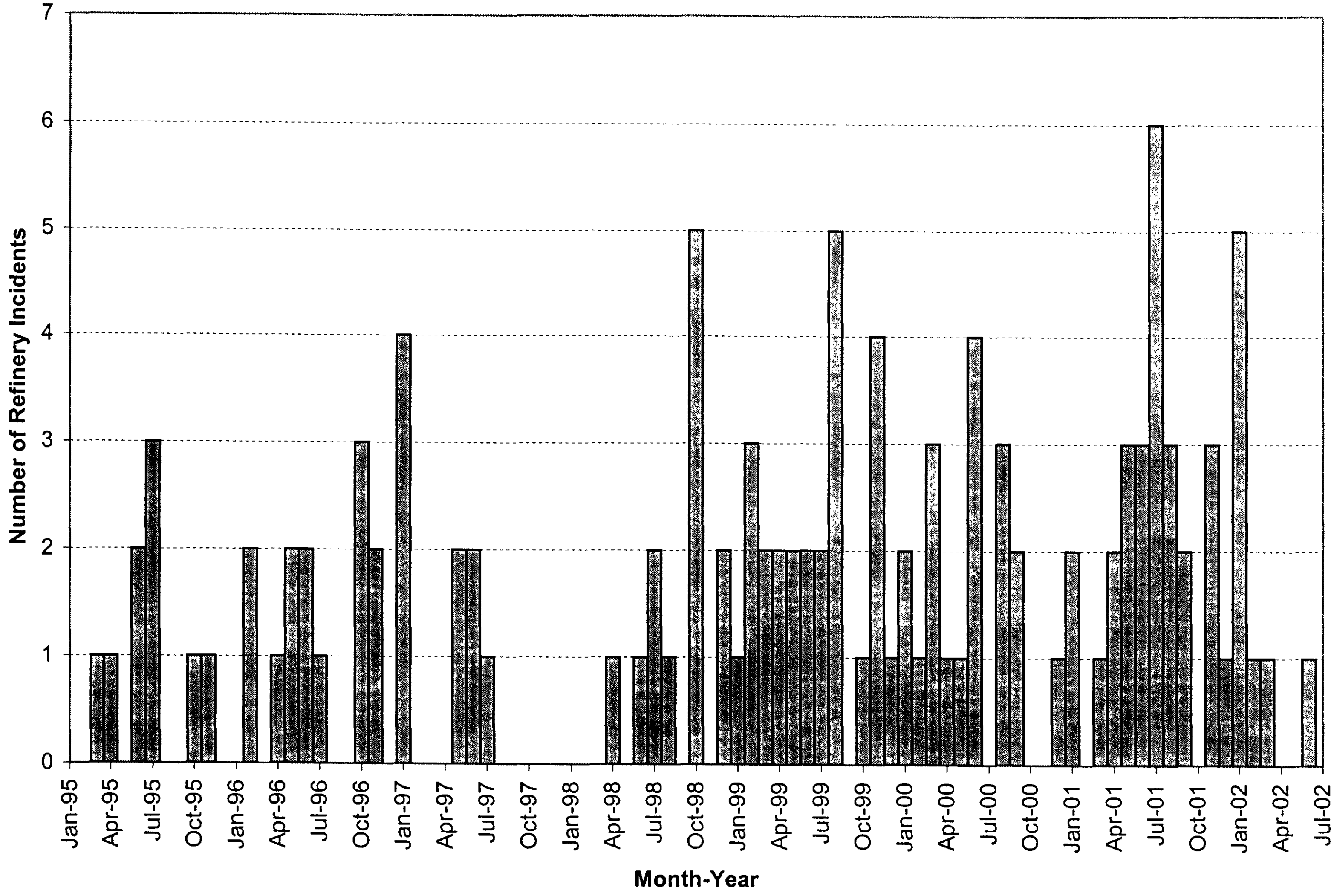
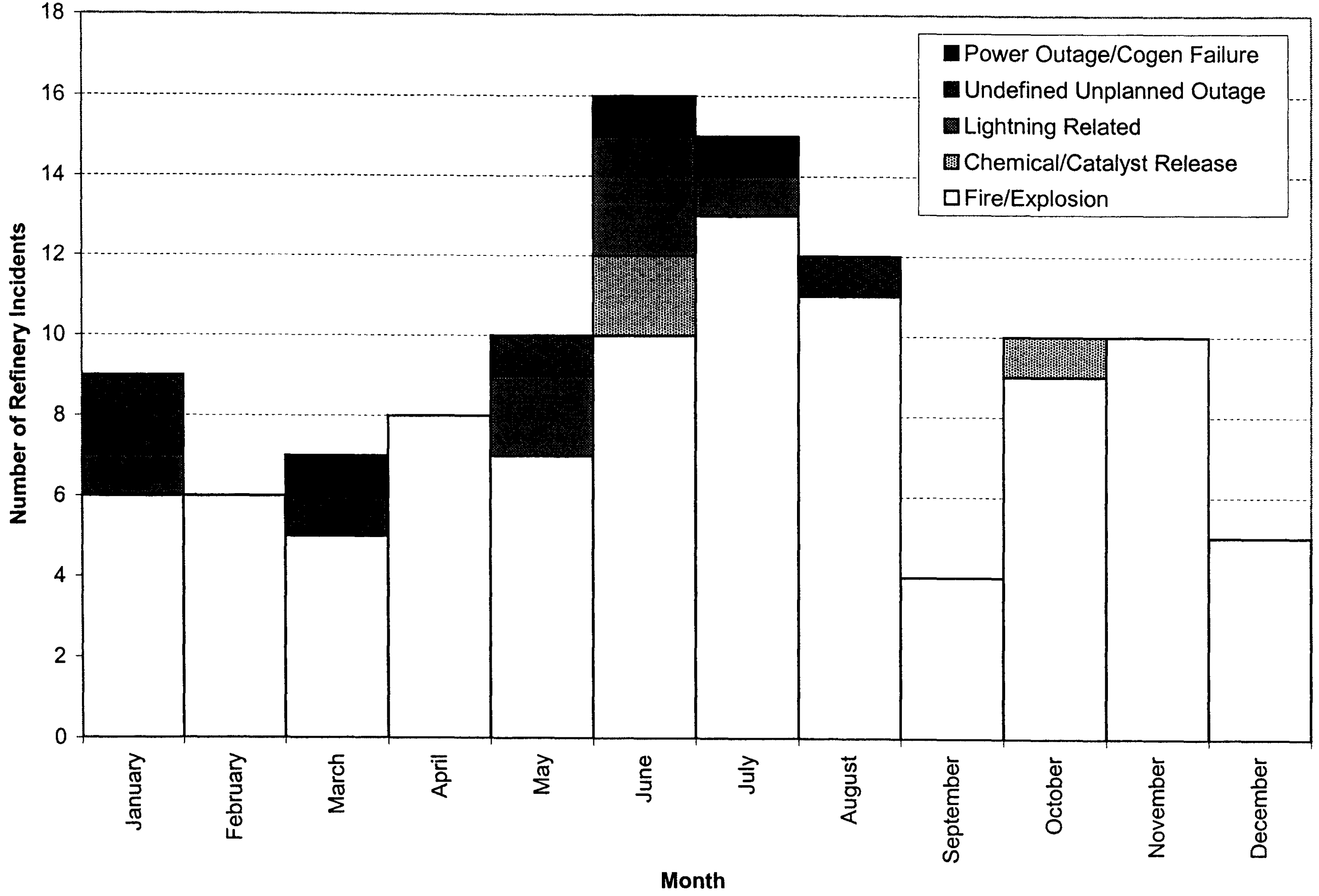


Figure 3.2:
Refinery Incidents By Month and Incident Type



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