Essays on the U.S. Oil and Natural Gas Industry

by

Thomas L. Littlefield

(Under the direction of William Lastrapes)

Abstract

This dissertation investigates various aspects of the U.S. offshore crude oil and natural gas production market. In the first essay, I investigate whether energy firms producing U.S. offshore oil and natural gas benefit from the volatility of crude oil prices. Lease rights to offshore oil and natural gas production in the U.S. are determined through auctions in which the leases, at least in part, do not respond to changes in the price of oil. The leasing process precludes the possibility of contracts perfectly extracting all rent at any point in time. My results however suggest that contracts, despite their lack of responsiveness to changes in the price of crude, have on average done a good job extracting rent over time.

In the second essay, I investigate the profitability of a sample of international oil companies and find that real profits of these oil companies display unit root behavior. One theory, the persistence in profit hypothesis, presumes this finding to indicate the existence of market power. Using a simple model of supply and demand I show that this implication may not hold. I propose an alternative test to ascertain whether barriers to entry exist within the U.S. offshore oil and natural gas production industry. The test suggests that offshore oil and gas production is competitive, which is contrary to public and main stream media opinion. Most importantly, this study produces a viable alternative to the persistence in profits method.

In the last essay, I conduct a natural experiment to determine the effect of the windfall profit tax (1980-1988) on the U.S. oil industry. I estimate marginal cost for a sample of international energy firms for both U.S. and foreign production. With these estimates I then conduct a difference in differences experiment to determine the effect of the windfall profit tax on several indicators of domestic investment and production. The results of this experiment suggest that the windfall profit tax had little effect in terms of relative importance.

INDEX WORDS: Firm Efficiency, U.S. Crude Oil and Natural Gas Industry, Imperfect Competition, Profit, Cost Functions, Unit Root, Windfall Profit Tax

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Chapter 1

Introduction

In the aftermath of the 2005 Hurricanes Katrina and Rita, media coverage frequently reported of energy firms earning historic quarterly profits and engaging in price gouging. As a reaction to the increase in end-use consumer product prices the Congress held hearings to reinstate the windfall profit tax and anti-gouging legislation, both of which are typical policy reactions. However, opinions differ about the level of competition between international energy firms and whether the situation requires policy intervention. I study the profitability of a sample of publicly traded energy firms and the effect of the windfall profit tax on these firms. The results of my research have important policy implications given the current contentions surrounding U.S. energy policy.

A cursory look at publicly traded international energy companies and their current position in the world oil and natural gas market reveals that all such firms only have access to 25 percent of the world's crude oil reserves. This limited market share suggests that, at least for the moment, it is unlikely that these crude oil- and natural gas-producing firms have any market power, giving them no clear incentive to underproduce. Researching the level of competition within the oil and gas production market further, I find that the time series of profits—where I measure profit as net income deflated by the GDP deflator—for some of the large energy firms exhibit unit root behavior. The time series of the real price of crude oil also exhibits unit root behavior. Additionally, for many firms in the sample, firm profit and price of crude oil are cointegrated. That is, firm profit tends to rise and fall with supply and demand shocks that affect the real price of crude oil.

The persistence in profits hypothesis addresses unit root behavior of profits and the implications of such behavior has for market structure. This hypothesis presumes that the finding of unit root behavior in profit, typically proxied by net income, indicates market power. I maintain however that unit root behavior of profit implies barriers to entry rather than market power. While barriers to entry are a necessary condition for market power, they are not a sufficient condition since barriers can be present in contested markets.

Having noted the cointegration relationship between profit—again measured by net income—and the price of crude oil, it seems reasonable that the difference in average costs, or rent, caused by barriers to entry will also exhibit unit root tendencies and will reflect shifts in the price of crude oil. It also seems reasonable that net income will reflect both profit and rent; therefore, the failure to reject a unit root in net income can lead to a false conclusion about the level of competition within a market.

I alter the persistence in profits method to test for market structure by taking advantage of the following theoretical result: barriers to entry drive profits to exhibit unit root behavior. Using a model of supply and demand, I illustrate how barriers to entry will lead to unit root behavior in profits, as measured by net income.

The two extreme cases—monopoly and perfect competition—exemplify this result. Economic profits will exhibit permanent shifts given permanent changes in supply and demand in the case of a monopoly; there is no mechanism to push profit toward zero in the long run because there are no other firms to compete with the monopoly. When there is competition, economic profits return to zero in the long run when a permanent change in supply or demand occurs. In sum, in the case of a monopoly, profit exhibits unit root behavior, and in the case of competition, profit is stationary.

The situation is slightly different with barriers to entry. It is possible for competition to occur within a market that contains barriers to entry as long as there is more than one firm in the market. Consider a patent—which functions as a barrier to entry by providing a specific firm with the sole rights to a low cost technology. Other firms cannot infringe upon this technology, so the cost advantage is not eliminated through competition. As long as the firm remains in operation, the rent earned by the firm displays unit root behavior in response to permanent shifts in demand and supply. The effect is identical for leases provided to firms who have the rights to low cost reservoirs. In effect the leases themselves have created barriers to entry.

My test for the structure of a market focuses on the least efficient firm; again, a competitive market will drive any rent or profit to zero for this firm in the long run. By conducting a unit root test on the least efficient firm's profit, this technique eliminates rent from the experiment, solving the problem of identifying profit from rent. Under the null hypothesis of a unit root the industry contains barriers to entry. The time series of profit is stationary under the alternative hypothesis implying that that the market is competitive. This updated method should provides a more accurate test for market structure than the persistence in profits empirical method allows.

Due to the complexity of the oil and gas industry, I narrow the scope of my analysis; I focus on U.S. offshore production of crude oil and natural gas. Upstream production is typically what concerns critics who discuss the profitability of the industry. Additionally, large firms tend to concentrate their production efforts in offshore reservoirs, and those firms are the focus of scrutiny by the government and the media.

However, a lingering issue about the structure of U.S. offshore lease agreements remains; a large proportion of the lease payment is independent of changes in the price of crude oil. This lack of flexibility in leases could lead firms to either receive or lose windfalls with unexpected changes in the price of crude oil. For instance, an unexpected rise in price generates a windfall for a firm that won lease rights when prices were expected to remain low. This unexpected windfall cannot be eliminated through competition, because the firm has exclusive rights to the reservoir. If on the other hand the acquiring cost of the reservoir is linked to the price of crude oil, any additional rent would be accounted for through the lease. As a consequence, testing the time series of profit for the least efficient firm may not eliminate potential unit root behavior of profit and/or excess rent.[1]

Scholarly work—e.g., Hendricks, Porter, and Wilson (1994) and Porter (1995)—has examined the competitiveness of offshore auctions. For example, Porter found that offshore leasing has done a relatively effective job at extracting rent. However, these auction theory papers focus primarily on data gathered prior to 1969, when the price of crude oil was fairly stable. The results of this research may no longer apply.

Accordingly, the structure of offshore leases has led to a testable joint hypothesis as opposed to a single testable hypothesis: does the least efficient firm earn profit and/or excess rent? There are two possible reasons for a measure of profit to exhibit unit root tendencies generate a joint hypothesis. First, the market is not competitive. Second, the fixed portion of leases has generated barriers to entry that have caused firms to earn excess rents. This testable joint hypothesis is the subject of two essays in my dissertation.

In addition to testing the time series of profits for the least efficient firm, I conduct another method for determining the structure of the U.S. offshore oil and gas market. This method—first developed by Appelbaum (1979) then refined by Ellis and Halvorsen (2002) and Atkinson and Cornwell (1998)—estimates the deviation between the price of an output, in my case crude oil, and the marginal cost of bringing the output to market. These estimates are derived using a system of cost equations with an additional equation included to account for the deviations between price and marginal cost. This additional test provides an independent means of determining the structure of a nonrenewable resource market and verifies my alternative to the persistence in profits method.

Although this empirical method is a stronger test than my alternative to the persistence in profits method, it does come at a cost: the empirical method requires more data. To estimate the system of cost equations, one needs data on the prices of inputs, the share each

[1] I am defining excess rent as the additional rent received by all firms in the industry driven by misperceptions of where the price of crude would be in the future. I am conceptually trying to separate this from rent which is the difference in firm average costs.

input represents of total expenditures, and the quantity of output. If my proposed method, which requires only net income, is valid, it will provide an alternative means of determining the structure of a market when data constraints make cost function estimation infeasible.

The third and final essay concerns the a windfall profit tax. This topic resulted from the above stated research interests receiving increased coverage in the news in relation to intervention. Policymakers, both past and present, commonly point to a windfall profit tax as the answer to perceived excess profits for energy firms. The reinstitution of a windfall profit tax was raised in both the 109th and the 110th congresses. In addition, as a presidential candidate, Barack Obama touted the idea during his election campaign and continues to mention it as an option after his election as president.

Though very little analysis has been conducted on the tax, there are some estimates of the effect of the tax. Lazzari estimates that the tax reduced domestic production by 3 to 6 percent and increased the importation of oil from 8 to 16 percent. He assumes a supply elasticity between a one half and one and the price of crude oil as equal to the marginal cost of delivering it to market, due to the competitive nature of the industry. However, this is unlikely to be true in an exhaustible resource industry because of the presence of rent. Within an exhaustible resource industry, the difference between the market price and long-run marginal cost is rent, and rent will be present for all but the least efficient firm until the resource is no longer economically viable.

Ferry (1993) reports the only other estimate of the effect of the windfall profit tax; however, his accounting for costs is not complete. He claims that the in situ value—the value of the crude reserves in the ground—should be used to determine the importance of the windfall profit tax. Yet the in situ value of crude oil fails to account for upstream expenditures to find the oil. He also omits the cost of bringing foreign oil to market; he thereby assumes that those costs changed identically to changes in U.S. costs. Additionally, Ferry's empirical method depends on questionable assumptions. Finally, given the termination date of Ferry's study and the additional data that has become available since its publication, the study is out of date.

The two studies previously mentioned focused on the effect of the tax on United States as a whole; however, the windfall profit tax was not levied uniformly on crude oil production nor was it levied uniformly on companies. The tax was set-up to provide incentives for new production and production from marginal wells paid a lower rate than wells that were producing substantial amounts of crude oil. More importantly, the tax was not levied on nondomestic production of crude oil. Although the tax was not levied internationally, individual firms did produce crude oil internationally.

These circumstances afford an opportunity to conduct a natural experiment. In my final essay, I estimate a difference in differences or natural experiment to determine the effect the windfall profit tax had on production, reserve creation, and other investment indicators for U.S. production of oil and natural gas. This analysis provides insight into potential ramifications resulting from a reinstatement of a windfall profit tax.

This dissertation is composed of six chapters, including this introductory chapter. The second chapter consists of a review of publications on my research topics and how my work contributes to this literature.

In the third chapter—my first essay—I test whether firms producing crude oil and natural gas off the shores of the United States are earning long-run excess rent and/or profit using data obtained from the Energy Information Administration. The dataset is a panel of annual data that contains 17 international energy firms and spans from 1977-2006. With this data, I estimate deviations between the price of crude oil and marginal cost for each firm in the sample. The deviations between marginal cost and the price of crude oil for this least efficient firm are stationary throughout the sample; this suggests that the market for U.S. offshore oil and gas production is competitive and leases for offshore reservoirs are effective at extracting rent.

In the fourth chapter—my second essay—I examine the persistence in profits hypothesis and present an alternative procedure for testing market structure. The implications of my test of the market structure of U.S. offshore oil and gas production and those of the persistence in profits procedure differ dramatically. While the persistence in profits procedure would suggests that the industry is not competitive, my test indicates not only that the industry is competitive but that the government auction system effectively collects rent due to the public. The results of my empirical test are in line with the results obtained in the third chapter.

In the fifth chapter—my third essay—describes a natural experiment I conduct to determine the effect of the windfall profit tax (1980-1988) on the U.S. oil and natural gas market. Using the cost function I developed in Chapter 3, I estimate marginal cost for a sample of international energy firms for both U.S. and foreign production. Then, I conduct a difference in differences experiment with those estimates to determine the effect the windfall profit tax had on several indicators of domestic investment and crude oil production. My results stand in contrast to previous claims as to the importance of the tax, which is to say, the tax had little affect on investment in and production from U.S. oil reservoirs.

The last chapter provides a description of the overall results. It includes my contribution to literature pertaining to the subjects of my research. Finally, it describes various policy implications resulting from my findings.

Chapter 2

Literature Review

The world market for oil is often described using models of cartels, models with a dominant firm, or some other form of market structure where pricing power is present. Alhajji and Huettner (2000) provide a review of some of these studies. Whether this framework for modeling the world oil market is correct, it does not preclude the possibility that certain segments of the industry are competitive or that there are firms in the industry that do not have pricing power.

A significant amount of research has been devoted to evaluating the level of competition between international energy firms. This research provides conflicting opinions on the level of competition among international oil companies. The reasons given for concern about the level of competition in the oil industry vary; authors have written about the amount and influence of vertical integration, concentration, and government regulation.

In reviewing the literature on vertical integration Bindemann (1999) notes, "There is no consensus yet on explanations and impacts of vertical integration."(p.9) and lists the following potential reasons given for vertical integration within the industry, "market power, technological interdependence, market uncertainties, strategic considerations with a view to increasing a rival's costs." (p. 9)

Adelman (1974) writes that the level of vertical integration in the industry is troubling in that vertical integration serves as barriers to entry in an industry. However, the 1970s and early 1980s were characterized by large increases in the price of oil which resulted in increased profit margins. During this period the market was inundated with independent firms in various stages of development of refined oil products. While vertical integration may potentially serve as a barrier to entry, Fan(2000) provides the following intuitive explanation for the cause of the vertical integration.

In 1973 OPEC nationalized oil assets from international energy firms, forcing the firms to develop new reserves in alternative areas as well as establish enhanced recovery methods in once-producing areas as a means of supply. However, downstream production now tied to this independent supply through long-term contracts was still subject to changes in the price of crude resulting from supply changes of the OPEC nations. The strain of these price movements brought on an era of vertical integration. These mergers were seen as a way to ensure a stable-priced supply of input through the various stages of refined oil production.

Alternatively, increased development of the forward and futures markets in the period following the 1978-81 oil shock led to a subsequent fall in transaction costs and alleviated the need for firms to be operationally integrated. Firms continued to hold a presence in downstream operations, but as Stevens (2003) suggests, modern major oil firms, although financially integrated, are not operationally integrated.[1] For instance British Petroleum may earmark 20% of its upstream petroleum production for its own refineries and let the market compete for the remainder. Although this environment hasn't always been in place, firms have generally been operationally independent since the 1990s. Firms now typically allow the market to determine where upstream output will be distributed.[2]

When describing the mergers of the 1990s Stevens states, "Whatever the reason, the industry became more concentrated. To be sure, various regulatory bodies in the United States and Europe forced the larger companies to divest certain key assets to protect competition, but the sense remains that the industry did become less competitive as a result." (2005, p.23) However, the 1990s were a period of cost cutting for the oil companies, another

[1]Stevens (2003) defines financial vertical integration as occurring when "the same company owns different stages in the same value chain" and operational vertical integration "where these different affiliates take their inputs or send their outputs to other owned affiliates" (p.96).

[2]Upstream and downstream production can be defined as follows: the upstream stage includes all operations required to deliver crude oil and natural gas to the market, and the downstream stage includes the refining of crude oil into petroleum products as well as the distribution of petroleum products from wholesale to retail markets.

sign of a competitive industry. Poor refining margins led to divestitures and upgrades of downstream production by major oil companies. The fall in profit margins in the late 1990s led to a movement in mergers, with the major oil companies creating what are known today as super majors.

Additionally, authors such as Measday (1982); Canes (1976); Rusin and Newport (1978); and Bleakley, Gee, and Hulme (1997) have pointed to independent firms having higher profit margins than the large integrated firms as evidence that markets are competitive. Bahree and Gold (2007) point out that as of late international profit margins of large energy firms are being siphoned by the nation-states where the reserves are located as well as competed away by national oil companies.

Duchesneau (1975) expresses concern over the level of competition between oil firms during the 1960s and 1970s but instead focuses on government interference in the market. Also concerned with regulation as potential barriers to entry but in downstream production, Chakravorty and Nauges (2005) note that nationally,

> [r]egulations have led to a proliferation of fuel blends known as "boutique fuels." For each of the three grades of gasoline, more than 15 types of boutique fuels are currently in use, leading to about 45 different fuel blends in use nationally. These fuels are costly to produce, but they also segment the market and increase the market power of refiners. (p. 1)

While the literature I have discussed so far focuses on the level of competition in the oil industry as a whole or downstream operations, I focus on upstream operations. It is the upstream segment of large integrated energy firms' revenues that is so often criticized by the media. Indeed, the profitability of downstream operations relative to upstream is so disproportionate it has led some economists to suggest the following reasons for not divesting: tax sheltering, market power, or as a hedge against oil prices(refining margins are negatively correlated with the price of crude oil).

When considering offshore or onshore production it is typically the offshore market that is suspected of not being competitive. There are a few reasons for this: first, high entry costs, Rockwood (1983) points to the large amount of capital necessary to produce offshore; second, the number of firms that produce offshore are far fewer than produce onshore; and third, the larger energy firms tend to concentrate their production efforts into offshore reservoirs and it is these firms that are the object of scrutiny from the government and media.

Therefore, I focus my attention on the U.S. offshore crude oil and natural gas production market. I ask if barriers to entry present in U.S. offshore oil and gas production market effect competition. I examine barrier to entry because they are a necessary condition for a firm to sustain any pricing power within a market. Without barriers to entry firms may enter and exit a market freely and with free entry, profits cannot be maintained in the long run.

Cairns and Harris (1988) state that there is evidence of barriers to entry in the market for offshore oil production. While their research deals with North Sea production, they find evidence of barriers to entry in the form of patents and access to technology, which are just as likely to influence production in other locations.

Mead, Moseidjord, Muraoka, and Sorenson (1985) also address the U.S. offshore oil industry, but they find that the market is very competitive. Using data that spans from 1954-1983, Mead et al. conduct a comparison of the internal rates of return for the firms producing on the Outer Continental Shelf and the internal rate of return on stockholder equity for all U.S. manufacturing companies. Their results indicate that the rate of return from offshore production is lower than that of manufacturing. They also conduct a least squares regression using data that encompasses the first 1,223 leases won on the Outer Continental Shelf in government auctions. They regress the high bids from these auctions on variables intended to capture: the expected value of a lease; the competitive structure of a lease, i.e., joint or single bid winner; the knowledge and distribution of information on the lease, whether the tract is a wildcat auction or whether it is a drainage or development auction;[3] and time dummies.

Other authors who have examined the level of competition in oil and gas production on the Outer Continental Shelf include Hendricks, Porter, and Wilson (1994) and Porter (1995). Hendricks et al. find that firms capture about a third of the rent in drainage tract auctions and a quarter of the rent in wildcat tract auctions. Porter finds that wildcat auctions held for U.S. offshore lease rights are in line with the behavior that would be expected from a symmetric non-cooperative equilibrium; specifically, he finds significant heterogoneity of winning bids and values placed on a tract as well as across tracts. The time span of the data used for these studies however is important, Hendricks et al. 1954-1969 and Porter 1954-1979. Both studies use time series in which significant portions occur prior to 1970. The time series of the price of crude oil was fairly stable before 1970 but there after becomes significantly more volatile. Given the proportion of data used in these studies that occurs previous to 1970 brings the validity of the results into question.

Appelbaum (1979) provides an alternative method for determining whether anti-competitive behavior is present in the U.S. offshore oil and gas industry. Appelbaum estimates a system of simultaneous equations; this system contains a set of share equations, the first order conditions derived from a generalized Leonteiff cost function, and an additional equation to determine whether there is a deviation between the price of oil and the estimated measure of marginal cost. Diewert (1982) gives a good exposition of the method used by Appelbaum in testing for anti-competitive behavior. I include Diewert's underlying theoretical basis for the method in the appendix to this dissertation.

Appelbaum finds the deviations between the price of crude oil and marginal cost to be statistically significant, this finding implies that the U.S. crude oil and natural gas industry is non-competitive. Ellis and Halvorsen (2002) point out that Appelbaum has incorrectly

[3]There are three types of leases auctioned: a drainage lease refers to lease that occurs within the same proximity as a discovered reservoir, development lease refer to leases that are typically being auctioned again because the lease was relinquished—often due to inactivity, wildcat auctions are tracts of land that there is no prior geological information available.

omitted rent in his study. The authors state that rent must be accounted for to correctly determine whether a firm is behaving competitively in an exhaustible resource industry. Ellis and Halvorsen, following essentially the same method as Appelbaum with the exception of attempting to account for rent, examine Inco, a Canadian Nickel producer, for non-competitive behavior.

To account for rent, Ellis and Halvorsen alter the Hotelling (1931) treatment of non-renewables. Instead of treating non-renewables as the output from production, they suggest non-renewables should be treated as an input and the resulting refined products as the final output. By including the quantity of the non-renewable resource in the cost function, but not including the price of the non-renewable resource, Ellis and Halvorsen set up a restricted cost function where the shadow value of the resource is implicitly imposed on the cost function. Consequently, to determine whether anti-competitive behavior is taking place in a non-renewable resource industry, it is only necessary to account for the output price of the final good and the marginal cost of the restricted cost function.

Of course, the presence of regulation within a market can often make the neo-classical assumption of optimal cost minimization inappropriate. The U.S. offshore oil and gas industry faces heavy regulation, and as such, it is unreasonable to assume that firms face an unconstrained cost minimization problem. Instead, as Atkinson and Halvorsen (1984) generalize, firms minimize cost given the regulatory constraints that they face. This implies that a firm's marginal rate of technical substitution for two inputs would not be equal to the ratio of its market prices. Atkinson and Cornwell (1994) also list as an additional reason for employing allocative inefficiency within a cost function, firms exhibiting sluggish adjustments to changes in input prices. Not only is the oil industry highly regulated, but the development of a reservoir can be a lengthy process, because demand and supply can be volatile in oil and gas markets sluggish responses to input prices also seem likely.

The use of stochastic frontier analysis avoids the need for making assumptions concerning unfettered neo-classical optimization. It also has been used to determine whether firms could potentially produce more given a set quantity of inputs in a production process or conversely the use of less inputs given a set amount of output, all of which is to determine a firm's level of technological efficiency. Stochastic frontier analysis, pioneered by Debreu(1951), Koopmans(1951), and Shephard(1953), has a long history with many contributors, but most important to this work are the advances made by Atkinson and Cornwell(1998), and Cornwell, Schmidt and Sickles (1990).

Atkinson and Cornwell extend Appelbaum's method for determining whether a firm is pricing at marginal cost by allowing allocative and technical inefficiencies. Atkinson and Cornwell incorporate: scale, technical, and allocative inefficiencies into the Appelbaum procedure. They point out that to correctly account for inefficiencies when estimating a cost system, all inefficiencies must be included or the resulting estimates will be biased. But Cornwell, Schmidt and Sickles point out, for samples with long time spans, it is unlikely that technical efficiency will remain constant. The authors devise a method to account for both cross-sectional variation and time varying heteroskedasticity in technical efficiency.

I model these constraints within the framework of a cost function by including allocative inefficiencies. I not only incorporate allocative inefficiencies into my cost function estimation but also time varying-technical and -scale inefficiency as suggested in Cornwell, Schmidt and Sickles (1990). Following Atkinson and Cornwell's estimation procedure while incorporating Cornwell, Schmidt and Sickless method for accounting for time varying inefficiency, I estimate the mark-up of seventeen firms as a method to determine the competitiveness of the U.S. offshore crude oil and natural gas production market.

Although it was not possible in Ellis and Halvorsen's research, since only one firm was used in the study, the use of panel data allows for an alternative procedure for identifying profit from rent. Instead of depending on the estimation of a restricted cost function to correctly identify the difference in marginal cost and the price of the output, as was done in Ellis and Halvorsen, an alternative method finds the least efficient frontier, allowing the market to identify profit from rent.

While for the most part I have followed Atkinson and Cornwell, I do vary the types of inputs used in the cost function I estimate. Due to accounting reporting procedures it is difficult to extend the typical inputs used in cost functions to an analysis of the oil and gas production industry. Instead, I follow Sardosky (1991) who substitutes drilling effort, geological and geophysical effort, and expenditures spent on land acquisition for capital, labor, and energy. Sardosky uses this cost function to estimate finding costs for the oil and gas industry in Alberta, Canada. The price of each input is calculated by dividing the expenditures for each category by the total number of feet drilled for drilling, the total number of crew months for geological and geophysical effort, and total area of land for land acquisition.

In sum, the market power of firms operating in the oil and gas industry has historically been a source of controversy. The existence of well-developed capital markets and the world-wide nature of oil exploration and development make it difficult to imagine that financial constraints limit competition. With the emergence of national oil companies and competition from independents, upstream operations have become increasingly competitive. One other possible source of excess rent for the offshore oil and gas industry is regulatory barriers to entry through government auctions. I investigate these possibilities in my first essay.

Now that I have tested the level of competition in the U.S. offshore oil and gas industry with one procedure, the question then becomes: will one method always be viable or is it useful to have more than one method to address the problem. Theoretically, there are alternative methods to address this problem: duality theory, introduced formally by Shephard (1953), provides alternative methods of addressing questions based on available data. Whether the data available is most suitable for a cost function, a profit function, or a production function, duality theory provides the theoretical justification for attacking a problem using different approaches.

One such alternative procedure, the persistence in profits hypothesis, attempts to determine whether a firm or industry has market power by examining their corresponding levels of profit through time. This procedure obviates the need to attain cost data by examining either the speed of convergence of one firm's short-run deviations of profit from the average of all the firms within its industry or an industry from all the industries within a market. The longer a firm's profits deviate from the average of the firms within the industry the more market power that firm is believed to enjoy; the same logic applies to an industry relative to the average of the market. The central assumption underlying the premise of the test is that barriers to entry do not exist; firms enter and exit markets rapidly enough to reign in deviations in profit.

Mueller (1986) and Geroski, Gilbert, and Jacquemin (1990) set the foundation for the empirical persistence in profits method. Examples of more recent work are Bentzen, Madsen, Smith, and Dilling-Hansen (2005) or Goddard, McMillan, and Wilson (2006), who adapt the original procedure by using a more consistent method for determining unit root behavior, i.e., panel unit root tests.

The persistence in profit empirical method has received some criticism for the use of accounting data in the procedure. Fisher and McGowan (1983) criticize the use of accounting returns as a substitute for economic returns, they state differences in methods used to account for depreciation are incompatible and therefore accounting returns and economic returns will differ. As a retort, Mueller points out that Fisher and McGowan's criticism assumes that firms have an incentive to overstate net income gains and understate net income losses; but Mueller states that this assumption is counter intuitive. Mueller writes that while there are potential problems with the use of accounting profit and care should be taken as a result, "[w]e conclude that accounting profits are not obviously inferior to market value measures of economic returns like Tobin's q, at least as measures of current economic returns." (1990, p.13) Mueller cites Lindberg and Ross (1981), who find evidence that the ratio of accounting profits to sales is positively correlated with Tobin's q. Mueller says this result shows that accounting profits are as satisfactory a measure of economic profit as Tobin's q.

One shortcoming that has not been properly addressed in regard to this line of research is the assumption that evidence of barriers to entry implies that a firm also possesses market power; that is, does the fact that there are barriers to entry in a market imply that a firm has market power? Barriers to entry allow firms to earn rent but that is not identical to market power. The question then is, does the persistence in profit empirical method determine if there is market power. It would appear that the question has only been correctly answered if rents—caused by barriers to entry—can be appropriately controlled for. Often the results of the persistence in profits empirical experiments have led to unsatisfactory answers to the questions they hope to address. In reviewing the results of previous studies using the persistence in profits empirical method, Goddard, McMillan, and Wilson write,

> Differences between firms in the long-run equilibrium rates of profit, and varying degrees of short-run persistence, have been explained by differences in industry structure, government regulation, and strategic behaviour at corporate level. (p.270)

It appears from this quote that many studies allow for rent to be a contributing factor in their results. I maintain that the persistence in profits measure will lead to false conclusions about market power given certain attributes of the oil industry. I attempt to address this issue by suggesting an alternative testing strategy.

Last, I ask what effect the windfall profit tax had on production and investment in the U.S. oil and gas industry. Little empirical work has been done on the windfall profit tax. This is likely due to the short duration the tax was enacted and the intended temporary nature of the tax; both of these issues would tend to minimize the effect of the tax and hence the importance of studying it. Lazzari (1990) gives a thorough overview of the details of the tax but has not done any empirical analysis within his study. Lazzari does however give estimates of the effect of the tax but they are based on two assumptions: the elasticity of supply in the oil market and that competition forces firms to produce at price equal to marginal cost. These assumptions allow Lazzari to calculate the effect of the windfall profit tax directly from the change in the price of crude oil and the quantity produced within the United States.

Ferry (1993) has conducted the only empirical study that I have been able to locate which investigates the effect of the windfall profit tax. Ferry attempts to determine the general response of investment in U.S. reserves to government regulation. He estimates the windfall profit tax delayed the development of 2.4 billion barrels of reserves. More specifically, 126 million barrels in new field discoveries, 31 million barrels in old field discoveries, 45 million barrels in extensions, and 3.3 billion barrels in revisions. Ferry also estimates that the windfall profit tax decreased production by 1.1 billion barrels.

To generate these estimates Ferry constructs a system of equations, the details of which can be found in the appendix. Ferry's study, although published in 1993, concluded before the tax was rescinded which likely means the results need to be reconsidered. The study also focused on the U.S. domestic market as an aggregate, while this procedure allows for an easy accounting of the overall changes in production and reserve numbers, aggregation could be problematic given the various factors that influence reserve creation and crude oil production. For example, Ferry does not account for costs in international markets when determining the importance of the tax.

As can be seen in Figure (5.1), there was a shift in reserve creation during the time of the windfall profit tax. But again, Figure (5.1) illustrates that there was also a difference in the costs of oil and gas production at the time. To correctly identify the effect of the windfall profit tax one must control for these differences in cost. If the conductor of the study does not control for these costs then he or she implicitly assumes that the cost of the available substitute input is changing identically with the input being examined.

In addition, the costs that Ferry has considered, development and operations, are not a complete accounting of costs that firms face in bringing oil and gas to market; this accounting neglects finding and acquisition costs. These shortcomings give reason for further investigation of the effect of the windfall profit tax.

For ease of exposition, Ferry also makes several simplifying assumptions. These include: oil and gas production can be modeled independently, the finite amount oil and gas reserves available are depleted at an exponential rate, producers expect a constant price of output as well as costs, and the real discount rate is constant. Ferry has also treated the U.S.'s supply of oil and gas as one resource pool which likely could be problematic. Pindyck (1978) has addressed this issue. Pindyck adds exploration to his model to account for economic incentives and the influence they have on stock of available reserves. Exhaustibility is a typical assumption used in estimation procedures based on Hotelling (1931) but it should be noted that very little empirical evidence has been found in support of the exhaustibility of resources as being an important factor contributing to the price of crude oil and natural gas.

As I stated earlier, the lack of scholarly work and the resurgence of demand for regulation to be placed on the oil industry begs for a closer look into the windfall profit tax and the effects it had on the industry. I investigate the effect the windfall profit tax had on the U.S. domestic oil industry.

Chapter 3

Do Energy Companies Benefit from Volatile Oil Prices?

3.1 Introduction

Profit margins of publicly traded energy companies during 2005-2008 have brought public criticism and suspicion of unfair pricing practices. Headlines such as "Exxon shatters profit records: Oil giant makes corporate history by booking $11.7 billion in quarterly profit; earns $1,300 a second in 2007" Ellis (2008) have become common place. Opposing this view, Taylor and Van Doren write, "No evidence exists of collusion or price fixing among investor-owned oil companies or gasoline retailers in domestic markets." (2006, p.3) Indeed, it appears that publicly-traded oil firms have little ability to alter the world price of crude oil. Only 25% of the world's petroleum reserves are accessible to these companies while the remaining 75% are controlled by state-owned oil companies[1] and OPEC nations. With limited access to the remaining scarce resources and therefore no pricing power, publicly-traded energy companies have little incentive to restrict supply.

One reason it may appear that oil firms earn large profits and are thought to have market power is that they earn rent on an exhaustible resource.[2] Firms may earn rent for several reasons. In the case of crude oil and natural gas extraction, the amount of rent that a firm receives varies substantially depending on unique geological features of reservoirs from which it produces and its own technical efficiency. Once a firm gains access to a reservoir, that firm or firms—in the case of joint production agreements—have exclusive production rights to the reservoir.

[1]Examples of state-owned oil companies are Gazprom and Pemex.

[2]Rent is a payment to the owner of a resource in excess of what is required for its use.

In the case of offshore crude oil and natural gas, production rights must change hands from the public domain to the private. To transfer production rights of a public resource to private companies, auctions are held in which leases are used to assign production rights for reservoirs to energy firms. These leases constitute a barrier to entry; the owner of a lease has exclusive rights to produce from the reservoir for which the lease is issued.

The heterogeneity of reservoirs combined with uncertainty surrounding the quality of a reservoir at the time of auction can lead to over and under bidding; in other words, excess or loss of rent earned by the resource owner. Porter (1995) has found empirical evidence of this heterogeneity in offshore auctions; he finds a wide range of bids on tracts as well as a significant rate of abandonment of tracts. Additional informational asymmetries can also be present depending on the type of auction; for instance, in the case of a drainage auction, firms with neighboring tracts to the one to be auctioned will have better information concerning the tract than firms who do not. In the case of wildcat auctions, firms may just have better geological and geophysical expertise and therefore can better determine the worth of a tract. While an auction should invoke a firm to bid its willingness to pay, Porter notes, "In an auction market with as much uncertainty as the OCS, firms have an obvious incentive to communicate, to avoid leaving too much money on the table." (p. 10) The Mineral Management Service—the agency which maintains the Outer Continental Shelf auctions—has pointed out in the past another possible cause for rent, many of the best reservoirs were auctioned off in the first several rounds of auctions held. Providing these tracts are still producing, early entries into the Outer Continental Shelf auction market would have received a first mover advantage. There are likely multiple other reasons to expect at least some firms maintain rent from these auctions. In sum, there are reasons to believe that firms may earn rent or bid too much for tracts of land.

Contracts—lease agreements—are imperfect beyond the static sense discussed above; they are also unable to extract all rent in a dynamic sense. The typical lease contract involves an upfront fixed payment, a percentage of future revenue (royalty) earned from the extraction of the resource, and a rental charge until production has been initiated. The royalty earned on a lease contract should vary with the amount known about the proposed resource site; however, the royalties charged in offshore lease auctions are fairly standard with little variation. Instead it is the upfront payment which determines the winner of the lease.

If crude oil prices were constant, then a competitive auction should drive these excess rents to zero. With stable crude oil prices, firms can—although not perfectly—predict where prices will be in the future and bid up to the point where price equals marginal cost plus rent with little excess rent. This is consistent with many auction theory papers on the subject, but these papers—in large part—are based on data previous to 1970. In 1970, a structural break occurs in the time series behavior of the price of crude oil, it becomes significantly more volatile after this point.

Using a battery of unit root tests, I find that the time series properties of the real price of oil exhibit unit root behavior which implies the series has an infinite variance. An infinite variance makes predicting the future behavior of the price of oil difficult. This fact makes it difficult for a contract to fairly capture all rent, whether positive or negative. Because the price of crude is not fixed and firms do not know where it will be in the future, they must guess and will undoubtedly be wrong.

In this study I examine the profitability of public energy companies. While there are a number of scholarly works dedicated to investigating the competitiveness of the oil and gas industry, they have maintained a wide scope. Because of the complexity of the industry, I narrow the scope of this study to the acquisition of the resource rights, the exploration, the development, and the production of U.S. offshore crude oil and natural gas. I will address some of this previous work and why the market structure of the world oil and gas industry justifiably allows for my narrowing of the scope in this paper. It is also this segment of international integrated firms' business most critics are concerned with when considering the profitability of large integrated energy firms. I also include non-integrated exploration and production firms (independents) as well.

The framework I use to determine the level of competition in the U.S. offshore oil and gas production market is based on Appelbaum (1979), Diewert (1982), Atkinson and Cornwell (1994), and Ellis and Halvorsen (2002). My cost function estimation follows Atkinson and Cornwell in that I allow for allocative, scale, and technological inefficiencies.

To obtain a measure of marginal cost for these firms I use a translog cost function; specifically, I estimate a shadow cost function because of the intensity of regulation in the oil and gas industry. For instance, there are limits placed on exploratory efforts previous to auctions. Environmental limitations are also a concern for offshore production, in particular the byproduct of saltwater in the production process. A large region of the U.S. coastal waters is inaccessible for drilling; as a result, energy firms have been forced to produce in deeper waters. Because capital is designed for specific depths, this movement into deeper waters forces firms to increase their capital stock.

3.2 Market Structure

While I believe the following is the correct way to view the world oil market, this view is not a necessary assumption for the analysis of this paper to hold true. The subsequent description serves as general background information to underscore the framework of this study.

The world oil market is best described by the dominant firm model with OPEC representing the dominant firm and the remainder of the world representing the fringe. The publicly traded energy companies represent a portion of the fringe. Because the world oil market is integrated and oil is a relatively homogenous commodity, the market structure does not change if we narrow our focus to the U.S. offshore oil production segment. Although the fringe represents the remainder of the world, for my purposes, everything in the fringe excluding the publicly traded energy companies is irrelevant. As such, within my diagrams the fringe represents publicly traded energy companies in either the world market or the U.S. offshore market.

An illustration of the oil market can be seen in the right hand side illustration of Figure 3.1 which depicts the dominant firm having market power. The dominant firm sets the price such that marginal revenue equals marginal cost thereby setting the world price. The fringe, depicted in the left hand side of Figure 3.1, produces where marginal cost equals the world price.

A competitive market should drive profit and rent to zero for the marginal firm. But this does not hold for all firms in an exhaustible resource market. In a market where firms have different average costs, only the least efficient firms should earn zero rent in the long run; therefore, if I want to determine whether a market is working efficiently I should focus on whether the marginal firm is earning profit and/or excess rent.

3.3 Method

Appelbaum's seminal work developed a framework to determine whether an industry or a firm is competitive. Appelbaum estimated a set of share equations—the first order conditions resulting from the differentiation of a cost function with respect to input prices—and an additional equation to measure deviations between marginal cost and the price of output.[3] Statistically significant deviations between the price of crude oil and marginal cost would suggest firms are benefitting from the structure of the market. I have included Diewert's (1982) exposition of the underlying theory of the procedure used by Appelbaum in the appendix. As Appelbaum states, the framework can be used

> not only for analyzing a non-competitive firm, but also for studying and investigating market structures, since it enables us to identify or distinguish among different market structures. (p. 287)

Ellis and Halvorsen note that Appelbaum's study of the oil industry is misleading in that Appelbaum has not accounted for rents, which would likely be present in an exhaustible

[3] To test the method Appelbaum coincidentally uses the oil and gas industry.

resource industry. As a result, Ellis and Halvorsen estimate a restricted cost function, restricted in the sense that it takes into account exhaustibility of natural resources. They conduct their study using data on Inco, an Albertan Nickel producer. The authors state that their estimation allows them to control for rents and therefore produces an accurate estimate of Inco's mark-up and hence its market power.

As an alternative to controlling for rent through the use of a restricted cost function, I rely on a panel data format to control for rents. To determine if a mark-up is present one simply needs to move to the least efficient cost frontier, where market forces should force profit and rent to zero. As I discussed in the introduction, I am differentiating between normal rents earned through lower average costs and what I have termed excess rents, which are earned through the inflexibility of lease agreements.

Atkinson and Cornwell suggest that the estimation of mark-up, or scale inefficiencies, can be biased without estimation of technological and allocative inefficiencies as well. As such, I follow their estimation procedure to account for any deviations of output price and marginal cost, or mark-up. Additionally, because the data set I use is thirty years of annual data, scale inefficiency is unlikely to have remained constant over the entire period. This is especially true given the volatile nature of crude oil prices. To allow mark up to vary through time I implement the method suggested by Cornwell, Schmidt and Sickles (1990).

The shadow cost equation can be expressed through the input based production function as follows[4]

$$\mathbf{C}^* \left(y_i, \frac{\mathbf{p_i^*}}{b_i} \right) = \min_{b_i x_i} \left\{ \left(\frac{\mathbf{p_i^*}}{b_i} \right) (b_i \mathbf{x_i}) | f(b_i \mathbf{x_i}) = y_i \right\} = \frac{1}{b_i} \mathbf{C_i^*}(y_i, \mathbf{p_i^*}). \tag{3.1}$$

Here y_i represents firm i's output. $\mathbf{p_i}$ is a vector of prices, both the output and input prices. The term $\frac{1}{b_i}$ represents the measure of firm's technological inefficiency. The vector $\mathbf{x_i}$ is a vector of firm inputs.

[4]I use Atkinson and Cornwell's nomenclature in the set up of my method.

Then the two-stage shadow-profit maximization problem becomes

$$\max_{b_i,\mathbf{X_i}} \{p_{y,i}(f(b_i,\mathbf{X_i}))f(b_i,\mathbf{X_i}) - \mathbf{p_i^*x_i}\} = \max_{y_i}\left\{p_{y,i}(y_i)y_i - \frac{1}{b_i}C^*(y_i,\mathbf{p_i^*})\right\}. \tag{3.2}$$

Maximization of equation (3.2) with respect to y_i leads to equation (3.3). Rearranging terms we have the real price of output on LHS and the firm's marginal cost on the RHS,

$$p_{yi}^* = p_{yi}'(y_i)y_i + p_{yi} = \frac{1}{b_i}\frac{\partial \mathbf{C}^*(\mathbf{y_i},\mathbf{p_i^*})}{\partial y_i}. \tag{3.3}$$

Because average costs vary for each firm, rent should vary for each firm. As Appelbaum notes, the test does not determine whether the demand for a firm's output is downward sloping or flat but rather whether a measure of mark-up appears in the shadow price such that a firm's output price is not equated with its marginal cost.

Rent should dissipate at the least efficient production frontier if in fact the market is competitive. That is, a firm should be willing to produce up until it neither earns profit nor rent in the long run. I have ordered the firms in the sample from most to least efficient. I have assumed they are unique which is not unreasonable given the uniqueness of geological features. Letting N represent the least efficient firm, then equation (3.3) will become

$$p_{yN} = \delta_{yN} + \frac{1}{b_N}\frac{\partial \mathbf{C}^*(\mathbf{y_N},\mathbf{p_N^*})}{\partial y_N} = 0 + \frac{1}{b_N}\frac{\partial \mathbf{C}^*(\mathbf{y_N},\mathbf{p_N^*})}{\partial y_N} \tag{3.4}$$

for the least efficient firm. The term δ_{yN} represents excess rent and/or profit for the least efficient firm. It is δ_{yN} that is identifiable by estimation and thus generates a testable hypothesis. The renewable-resource long-run profit maximizing condition should apply for the least efficient firm, i.e. the first order condition for profit maximization should be the typical price minus marginal cost equal to zero.[5]

Unlike many of the studies on nonrenewable markets, I have not explicitly included a term to account for exhaustibility as some authors have; there are two reasons for this.

[5]It should be noted that, while I have estimated these deviations through a cost system, there are alternative methods that would work as well; specifically, one could estimate a profit function instead of a cost function and obtain a supply equation.

First, I am already implicitly accounting for the exhaustibility of natural resources within the cost function; the inputs I use, drilling, geological and geophysical (G&G), exploration and development are expenditures on the resource itself and will increase as the resource is depleted. Second, the firms I am examining are not tied to one pool of reserves.

3.4 Empirical Results

The data I use to estimate the cost function are collected by the Energy Information Administration (the statistical arm of the Department of Energy). The data set is a panel of annual data containing 47 U.S. based energy firms and spans from 1977 to 2006. It also includes three foreign owned subsidiaries: BP America, Shell Oil, and Total Holdings USA. Because I am only concerning myself with offshore production, all but 17 firms must be eliminated. Despite the elimination of observations, the panel remains unbalanced. More details concerning the Financial Reporting System Data can be found in the appendix. I divide each firm's annual raw materials sales revenue by the number of barrels of oil equivalent sold that year as a measure of the price they received for their output. Any firm specific data are restricted by the Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA). I also include the following macroeconomic variables as instruments: U.S. expenditures, U.S. exports, U.S. GNP, U.S. private investment, U.S. imports, and U.S. consumption. I divide all nominal variables by the producer price index to obtain real values. I obtain all the data I use for instruments in the estimation as well as the data on the producer price index from the FRED II database at the St. Louis Federal Reserve Bank, (http://research.stlouisfed.org/fred2/).

Although energy firms have two outputs in their upstream operations, crude oil and natural gas, I am considering them as one. This is because firms do not typically explore for natural gas, rather it is a byproduct of efforts to locate oil reservoirs. It is easy to convert natural gas into oil equivalent using the energy content within each. There is approximately the same energy content in 6,000 cubic feet of natural gas as there is in one barrel of oil.

So it is possible to convert natural gas into oil equivalent terms or barrels of oil equivalent (BOE).

Given the nature of the oil and gas production industry, it would be difficult to separate inputs into capital, labor and fuel for the firm. Instead, I separate inputs to conform with the method the industry uses to report their financial disclosures. Sardosky (1991) also uses this form to estimate scarcity of oil in Alberta. In the model, total costs are a function of both crude oil and natural gas production, as well as the input prices of exploratory and developmental effort minus geological and geophysical (G&G) effort,[6] geological and geophysical effort, and the resource to be extracted. There is a semblance of dividing inputs by those that will depreciate over time, drilling expenditures; those that are more closely related to labor, geological and geophysical effort; and those that are directly related to the resource itself, expenditures on acquiring resource rights and the costs involved with the actual lifting of the resource. Regardless, the manner in which a firm's inputs are disaggregated is largely arbitrary as long as they meet certain conditions within the cost function framework.

I have defined the prices of inputs as follows:

$$\begin{aligned} p_{drilling} \equiv & \left(\frac{\text{expenditures on exploration and development excluding G\&G}}{\text{total number of exploratory and development wells drilled}}\right) \\ & \times \left(\frac{1}{\text{reserves}}\right), \end{aligned} \tag{3.5}$$

$$p_{G\&G} \equiv \left(\frac{\text{G\&G expenditures}}{\text{net acreage}}\right), \tag{3.6}$$

and

$$p_{resource} \equiv \left(\frac{\text{property acquisition costs}}{\text{reserves}}\right) + \left(\frac{\text{production expenditures}}{\text{production}}\right). \tag{3.7}$$

[6] Geological and geophysical expenditures are often considered a subcategory within exploration expenditures.

Equation (3.5) defines the price of the first input which is exploratory and development or drilling effort. The first term is the total expenditures on developmental effort and exploratory effort minus geological and geophysical effort per the total amount of developmental and exploratory wells drilled. The second term is the inverse of the contemporaneous amount of reserves, where reserves are measured in millions of barrels of oil equivalent. All expenditures are measured in millions of dollars. I convert all of the nominal values to real values by dividing by producer price index. I define the price of geological and geophysical effort, Equation (3.6), by the ratio of total expenditures on geological and geophysical effort to the amount of net acreage the firm possesses. I am assuming the more land a firm possesses the more effort it requires to explore. Finally, Equation (3.7) defines the price of the resource as the sum of the following two ratios. Total expenditures on acquisitions of leases to the firm's reserves—measured in barrels of oil equivalent—and the second term is the total expenditures on production to the number of barrels of oil equivalent produced.

The shadow cost function can be expressed as follows:

$$\begin{aligned}
\ln C^*_{y,w,t} = {} & \alpha_0 + \ln\left(\tfrac{1}{b_i}\right) + \alpha_y \ln y_{it} + \alpha_t t \\
& + \textstyle\sum_{j=1}^3 \beta_j \ln w^*_{jit} + \tfrac{1}{2}\alpha_{yy}(\ln y_{it})^2 \\
& + \tfrac{1}{2}\textstyle\sum_{j=1}^3 \sum_{j'=1}^3 \beta_{jj'}(\ln w^*_{jit})(\ln w^*_{j'it}) \\
& + \textstyle\sum_{j=1}^3 \gamma_{ij}(\ln y_{it})(\ln w^*_{jit}) \\
& + \tfrac{1}{2}\alpha_{tt}t^2 + \textstyle\sum_j^3 \nu_{tj}(\ln w^*_{jit})t,
\end{aligned} \tag{3.8}$$

where the subscript $i = 1 \dots N$ refers to the number of firms, $j = 1 \dots 3$ is the number of inputs, and t indicates a variable does not remain constant through time. y represents output of the firm, $w^* \equiv kp$ is a first order approximation of the market price, p. It is this first order approximation that allows for allocative inefficiency; that is, a firm is only efficient when $w^* = p$. t is a time trend, I also include its square and interaction terms with prices and output. I include dummy variables to differentiate between differences in technology, b_i.

The shadow share equation for each input is

$$S^*_j = \alpha_j + \sum_{j'}^{J} \beta_{jj'} w^*_{j'it} + \gamma_{ij}(\ln y_{it}) \qquad \text{for} \quad j = 1, 2, 3 \tag{3.9}$$

where S^* is the shadow share for firm j and it can be defined as $S^* \equiv k_{ji}p_j x_j / C^*$. The shadow share, much like the shadow price, results from a firm's constrained effort to minimize costs. They are the efficient shares and prices given the constrained environment in which the firm resides.

Combining equations (3.8) and (3.9), I estimate the following system of equations composing the augmented shadow-cost system

$$\ln C_{it} = \ln C^*_{it} + \ln\left\{\sum_{j=1}^{3} S^*_{jit} k^{-1}_{ji}\right\} + \xi_{it}, \tag{3.10}$$

$$S_{jit} = \frac{S^*_{jit} k^{-1}_{ji}}{\sum_{j=1}^3 S^*_{jit} k^{-1}_{ji}} + \omega_{jit}, \tag{3.11}$$

and

$$\begin{aligned}p_{yt} = \delta_{yi} + \tfrac{1}{b_i}\left[\alpha_1 + \alpha_{yy}\ln y_{it}\textstyle\sum_{j=1}^{3}\gamma_{ij}(\ln w^*_{jit})\right]\exp\Big\{\alpha_0 + \ln(\tfrac{1}{b_i}) \\ +\alpha_y \ln y_{it} + \alpha_t t + \textstyle\sum_{j=1}^{3}\beta_j \ln w^*_{jit} + \tfrac{1}{2}\alpha_{yy}(\ln y_{it})^2 \\ +\tfrac{1}{2}\textstyle\sum_{j=1}^{3}\sum_{j'=1}^{3}\beta_{jj'}(\ln w^*_{jit})(\ln w^*_{j'it}) \\ +\textstyle\sum_{j=1}^{3}\gamma_{ij}(\ln y_{it})(\ln w^*_{jit}) \\ +\tfrac{1}{2}\alpha_{tt}t^2 + \textstyle\sum_{j}^{3}\nu_{tj}(\ln w^*_{jit})t\Big\}y_{it}^{-1} + \epsilon_{it}.\end{aligned} \tag{3.12}$$

Equation (3.10) is the actual cost function, equation (3.11) represents both of the actual share equations, and (3.12) is the augmented price equation. ξ, ω, and ϵ represent normal i.i.d. error terms, p_{yt} represents the price of oil. Again, δ represents the deviation between the price of output and estimated marginal cost. I impose the following restrictions on the cost function:

$$\begin{aligned}&\textstyle\sum_{j}^{3}\beta_j = 1, \\ &\textstyle\sum_{j}^{3}\beta_{jj'} = 0 \quad \forall j', \\ &\textstyle\sum_{j}^{3}\gamma_{ij} = 0, \text{and} \\ &\textstyle\sum_{j}^{3}\nu_{jt} = 0.\end{aligned} \tag{3.13}$$

These restrictions are a function of imposing homogeneity on the total shadow cost function through shadow prices. I also impose symmetry restrictions, $\beta_{ij} = \beta_{ji}$.

To estimate the above system of equations I use RATS non-linear estimation procedure with instruments. This procedure conducts non-linear three stage least squares. I include lags of the possibly endogenous right-hand-side variables as instruments as well as their interaction with the trend, output, and their squares. I also include the six macroeconomic variables I discussed earlier as instruments.

If I were to estimate the cost system as it appears now I would be making the assumption that δ_i remains constant for the entire time span of the sample. This assumption is obviously incredible and as such I adopt the following empirical method to correct for it. I follow

Cornwell, Schmidt and Sickles's method for allowing time variation in inefficiencies. Although Cornwell, Schmidt and Sickles applied this method to technical inefficiency instead of scale inefficiency, the premise remains the same. Both are estimated by including firm dummies with an additive error. Cornwell, Schmidt and Sickles suggest representing the inefficiency by interacting a set of firm dummies with the time trend and its square

$$\delta_{it} = \Omega_{i1} + \Omega_{i2}t + \Omega_{i3}t^2, \tag{3.14}$$

where Ω is a set of firm dummies.

Like Atkinson and Cornwell, I estimate the models in sequential order. That is, I first estimate the model with only technical efficiency, then with both technical and allocative, and finally all three. All estimations converge quickly and smoothly.

Again, my intention of conducting this empirical experiment is to determine whether there is any prolonged deviation between the real price of oil and marginal cost for the least efficient firm. As I stated earlier, I do not explicitly account for the rent within the system of equations, but because I am using panel data I am able to separate rent from any excess rent and/or profit by moving to the least efficient firm. If offshore auctions are efficient distributors of resources the least efficient firm should not earn rent, excess rent, nor profit.

Before turning to the estimation results, I first run several tests. I conduct several Wald tests to determine whether including technological and allocative inefficiency is necessary. That is, I test whether $w_i^* = p_i, \forall i$ and if $\frac{1}{b_i} = 0, \forall i$. Both tests soundly reject the exclusion of the inefficiencies.

The Allen-Uzawa elasticities as well as substitution and own price elasticities are pictured in Figures 3.2 and 3.3. These results suggest that the inputs are substitutes. It also appears from the figures that drilling is the most elastic of the inputs but becomes less so over time. The least elastic of the inputs is the resource; in fact, the elasticity for the resource is inelastic which seems reasonable given the importance of the resource in the production process.

I also examine whether the cost function exhibits concavity and monotonicity. The firms' estimated shadow shares are positive through time—satisfying the monotonicity requirement—as required for a cost function; this can be seen in Figure 3.4. The Hessian for the cost function is negative semi-definite which satisfies the concavity requirement.

The results of my estimation of the full augmented shadow cost system, including all three types of inefficiency, can be seen in Table 3.1. It appears from the results that the trend, its square and its interaction with the price of geological and geophysical effort are all statistically insignificant. Both output and input prices have statistically significant positive effects on total expenditures for the average firm.

Figure 3.5 displays three graphs: the real refiners' acquisition price of crude oil;[7] the average level of technical efficiency for all firms in the sample as well as the maximum and minimum level of technical efficiency in each period among all firms in the sample; and the average deviation between the real price of oil and the estimated marginal cost as well as the maximum and minimum deviation in each period among all firms. To be clear, the maximum and minimum series make up a maximum and minimum convex shell of all the observations for each firm within the sample.

Technical efficiency can only be measured ordinally. Again, allowing efficiency to vary through time, I set the level of efficiency for the most technically efficient firm over all of the sample periods to be equal to one. As can be seen in Figure 3.5, both the greatest and least technically efficient periods are achieved in the last time period of the sample. Also, the average of the sample has remained close to the lower boundary of the sample. This suggests that the distribution of technological efficiency has dispersed non-symmetrically; the weight of the distribution lies along the minimum boundary of the sample which indicates that there are only a few relatively efficient firms within the sample. The maximum series resembles

[7]I use the refiners' domestic price as the price of crude oil. This series is available at the Energy Information Administration's website, (http://www.eia.doe.gov). To obtain the real price, I deflate the series by the GDP deflator.

multifactor productivity for the United States, e.g., manufacturing, private business, and private non-farm business.

It is apparent from Figure 3.5 that some firms have experienced different rates of return on their investments. The average firm in the sample appears to have earned some rent with the conclusion of price controls but competition appears to have arrested that. There also seems to be a change in the rate of growth in scale efficiency in 1992; there are several possible explanations for this change: the early 1990s were marked with low crude oil prices, energy firms generally experienced low profit margins in the late 1990s, and increased competition.

It seems odd however, that firms have not experienced large increases in profit and/or excess rent, particularly in the last few years of the sample. There certainly have been large increases in the price of crude oil and as the general news media has pointed out, several firms have benefited greatly from these increases in price. It is of course possible that firms simply have a better understanding of where the price of crude will be in the future but some changes in price must be unforeseeable; for instance, after the first Gulf War or Hurricanes Katrina and Rita, and yet there is very little evidence of these changes in any of the series.

3.5 Conclusion and Policy Implications

I have estimated an augmented shadow cost system allowing for technical, allocative, and time varying scale inefficiency. The resulting time varying scale inefficiency represents deviations in the price of crude oil from firm marginal costs. These deviations suggest that current attitudes towards the oil and gas industry and corresponding policy proposals are unwarranted. That is, it appears that the barriers to entry that exist in the U.S. offshore oil and gas industry have not hindered the competitive process.

However, the lack of volatility in all of the scale efficiency series is troubling. The price of oil has varied significantly over the three decade time frame I investigate. Large up swings in the price of oil should be reflected in increases in the all of the series but these increases have not been realized in Figure 3.5. Of course, it is possible that firms understand to some extent where prices will be in the future and therefore future changes in rent are being accounted for in the bidding process.

Table 3.1: GMM-Single Weight Matrix

Parameter	Estimated Coefficient	standard error	p-value
α_0	-5.313	0.074	[0.000]
α_y	0.749	0.533	[0.000]
α_t	-0.018	0.018	[0.334]
β_R	0.390	0.040	[0.000]
β_{drill}	0.275	0.028	[0.000]
$\beta_{G\&G}$	0.334	0.000	[0.000]
$\beta_{R,R}$ †	0.003		
$\beta_{R,drill}$	-0.045	0.005	[0.000]
$\beta_{R,G\&G}$	0.042	0.006	[0.000]
$\beta_{drill,drill}$	0.022		
$\beta_{drill,G\&G}$	0.022	0.003	[0.000]
$\beta_{G\&G,G\&G}$	-0.064		
$\gamma_{Y,R}$	-0.068	0.014	[0.000]
$\gamma_{Y,drill}$	0.012	0.002	[0.000]
$\gamma_{Y,G\&G}$	0.055		
$\nu_{t,R}$	-0.007	0.004	[0.084]
$\nu_{t,drill}$	0.003	0.003	[0.389]
$\nu_{t,G\&G}$	0.004		
α_{yy}	-0.0176	0.018	[0.334]
α_{tt}	0.001	0.002	[0.451]
$\tilde{R}^2$	0.799		
N	435		

I do not include coefficients for the dummy variables in any of my results for reasons of confidentiality.

†Some of the coefficients were imposed through the identification restrictions and therefore have no standard errors.

Figure 3.1: Dominant Firm with Competitive Fringe

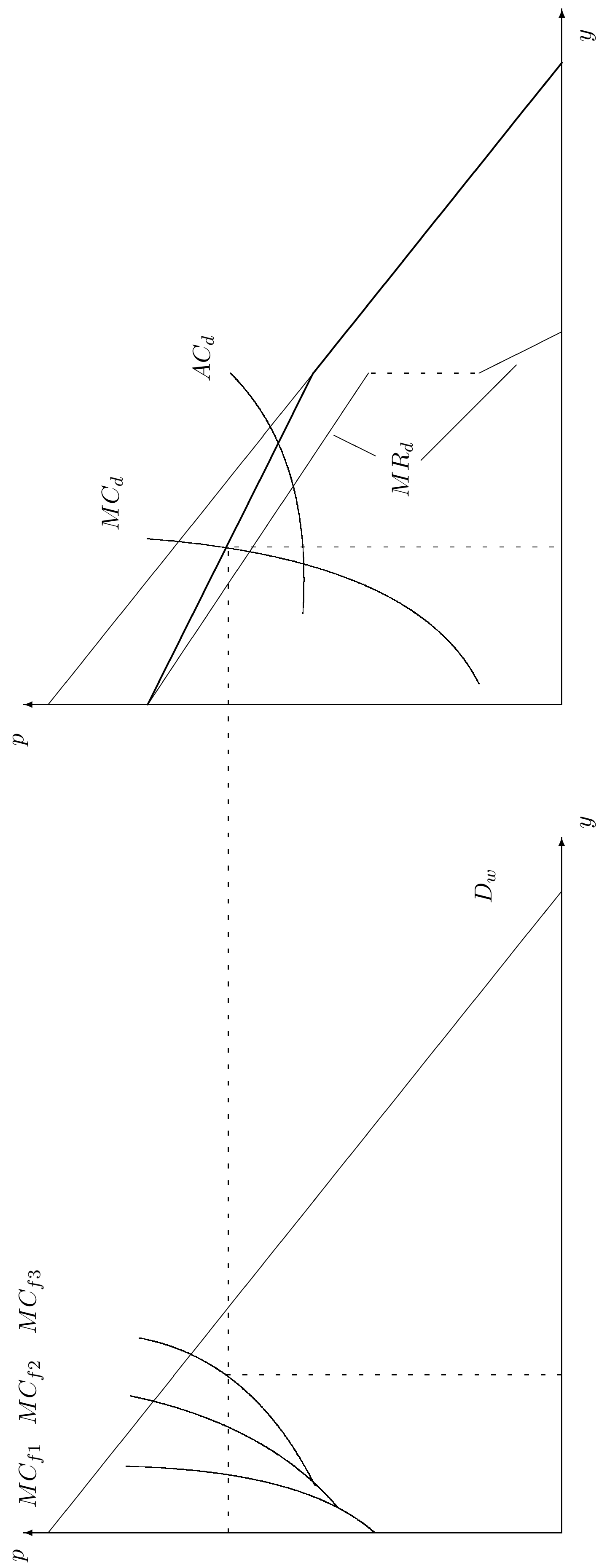


Figure 3.2: Allen-Uzawa Elasticities

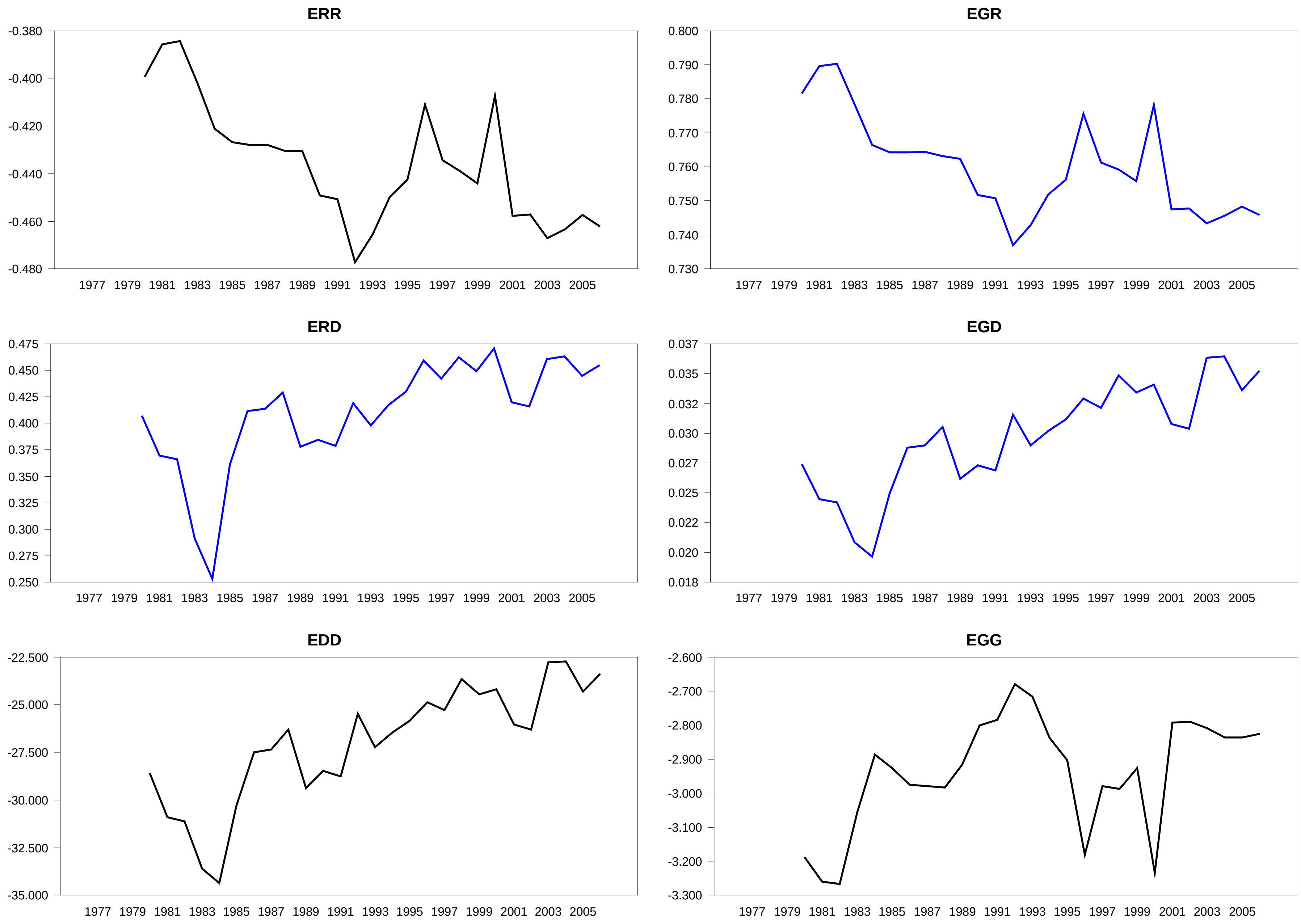


Figure 3.3: Demand and Substitution Elasticities

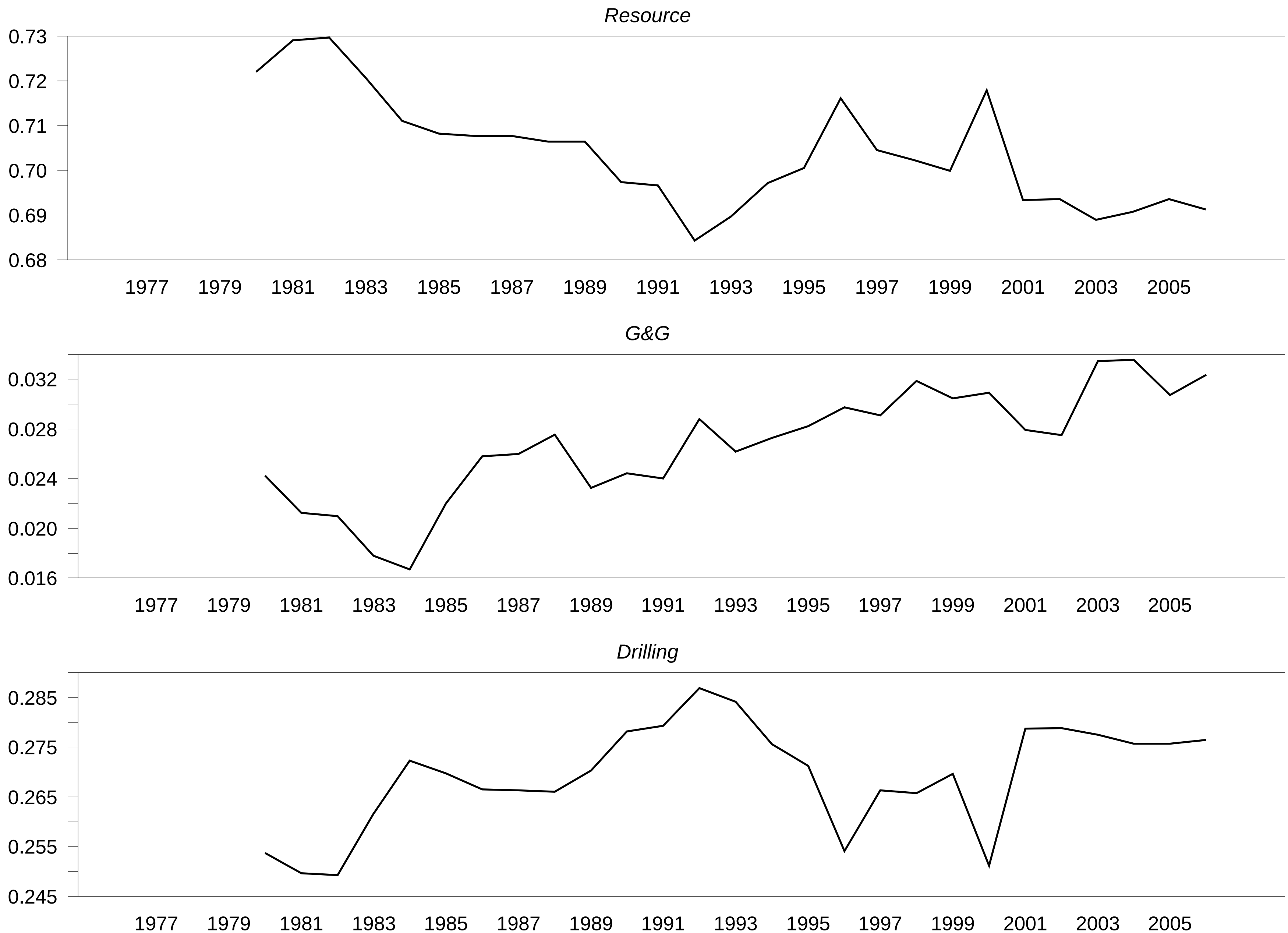
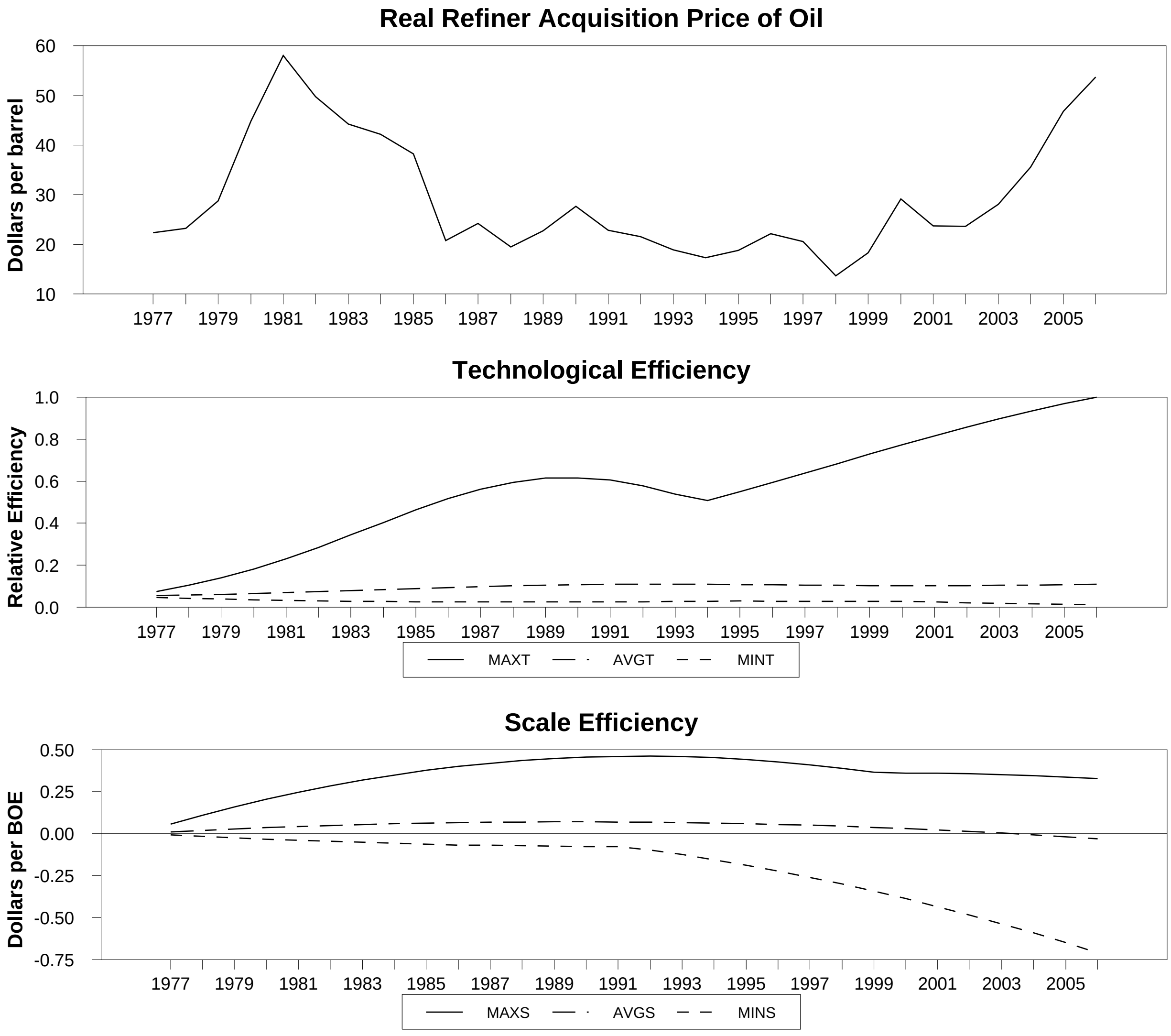


Figure 3.4: Average Fitted Shares

Figure 3.5: Deviations Between the Price of Crude Oil and MC



Chapter 4

A Test for Barriers to Entry

4.1 Introduction

The competitiveness of the crude oil market has frequently been questioned by economists. I propose a possible test to determine whether the U.S. offshore oil and gas industry is competitive. The testing procedure I propose is an adaptation of the empirical test used for the persistence in profits hypothesis which evaluates a time series of a firm or industry's profit as a measure of market power. I maintain the persistence in profits measure will lead to false conclusions about market power given certain attributes of the oil industry; therefore, I adapt the measure to take these into account.

While there are potentially stronger tests than the test I have proposed, they require a significant increase in the amount of available data. For example, estimating a cost function is often difficult due to data constraints. While data availability is not an issue in determining the market structure of the U.S. offshore oil and gas industry, often cost functions are not viable alternatives; therefore, having an alternative to the persistence in profits hypothesis is important. The U.S. offshore oil and gas industry provides a means to compare the results of my alternative test and the persistence in profits method with a third alternative test; in this case, the testing procedure first developed by Appelbaum (1979).[1]

[1] I have included a section on Diewert (1982) explanation of the test used in Appelbaum in the appendix.

4.2 Overview of the persistence in profits hypothesis

Typically two unit root tests are run by a researcher when trying to determine if market power is present. The first test compares a corporation's profits to the average level of profit of all the industry participants. The typical measure for profit used in testing procedures for the persistence in profits hypothesis[2] is profit plus interest payments divided by total assets where profits are measured as net income. A measure of deviation from the industry average profit is then constructed

$$\rho_{i,t} \equiv \pi_{i,t} - \bar{\pi}_{I,t}, \tag{4.1}$$

where $\pi_{i,t}$ is defined to be firm i's profit and $\bar{\pi}_{I,t}$ is defined to be industry I's average profit.

The analysis is typically undertaken by using a form of the Dickey Fuller Unit Root test. Variations of the testing procedure include using Augmented Dickey Fuller tests and/or panel unit root tests. The following is a basic Dickey Fuller test for a unit root

$$\Delta\rho_{i,t} = \Theta_0 + \gamma_1\rho_{i,t-1} + \xi_t, \tag{4.2}$$

where Θ_0 is a constant (termed a drift) and ξ_t is an i.i.d. white noise process. γ_1 is the coefficient of interest in this regression. It can be interpreted as the speed at which the individual firm's profit level returns to the average profit level for the industry. The duration of time a firm earns abnormal profits determines whether it is considered to have market power. Abnormal profits are defined as extended deviations in the profit level of a single firm from the average profit level for all firms within the industry.

The second test used in the persistence in profits hypothesis determines whether the industry as a whole possesses some abnormal profit level. Here the deviation in industry profit level from the average of all other industries in the sample is measured in a similar fashion to the first test. This second test requires a measure of profit for all industries. $\bar{\pi}_{A,t}$ represents the average return for all industries located in the region in which the study takes

[2]The following is taken from Geroski (1990).

place. The structure of the empirical test is identical with the corresponding variables as seen in the following two equations:

$$\rho_{I,t} \equiv \bar{\pi}_{I,t} - \bar{\pi}_{A,t}, \tag{4.3}$$

$$\Delta\rho_{I,t} = \Theta_0 + \gamma_1 \rho_{I,t-1} + \xi_t. \tag{4.4}$$

A specific example can be seen in the panel data experiment of Bentzen, Madsen, Smith, and Dilling-Hansen (2005). Bentzen et al. test for a unit root in measured Danish rates of return for individual firms as well as industries. Their sample consists of 1,310 Danish firms under the criterion of full data availability for the years 1990-2001. Bentzen et al. find varied results, the unit root tests they conduct on individual firms generally lead to rejection of unit root behavior of profits. When using industry level data, Bentzen et al. attain mixed results between unit root behavior and stationarity. The authors maintain that the inability to reject a unit root is suggestive of market power. This sentiment is generally echoed throughout the publications expounding upon the persistence in profits hypothesis.

4.3 Criticism

Although my focus is on nonrenewable resource markets, I believe my criticism of the persistence in profits hypothesis applies whenever an industry exhibits rent is likely to be present in an industry. There are many reasons this may occur, such as when an industry relies on patents or experiences low turnover in management. In the case of the oil and gas industry, technology provides the difference in average costs but leases provide the means to sustain them. In this instance the above testing strategy proves insufficient since it is unable to differentiate between economic rent and economic profit. To expand on this point I discuss the possible cases that can be encountered within this framework.

The first case to consider occurs when profits of the individual firm exhibit a unit root and those of the industry as a whole do as well. If these two unit roots are cointegrated then the time series of ρ_t will be stationary and any permanent difference between the two series will not be measured by γ_1. The omission is due to the difference between the individual firm and the average of the industry being taken as the steady state relationship when estimating γ_1. γ_1 will only capture the rate of return from a temporary shock to the steady state relationship between the firm and the average. Both permanent economic profit and economic rent will be excluded from the estimated coefficient.

The second case occurs when both time series are unit roots but not cointegrated. In this case, the difference between the two series will also be a unit root and will never revert to any stationary mean; therefore, γ_1 will not reflect any permanent difference between the two series. The third case occurs when the industry mean is a unit root. Here the difference will again be a unit root and as in case two will never revert to a stationary mean. The fourth case occurs when the individual firm time series is stationary and the industry time series is a unit root. Again, this would be similar to cases two and three. The last case to consider occurs when both the individual firm and the industry average are stationary. The same points argued above also apply to the broader industry testing procedure, only in the last case would industry returns converge to the mean of the sample.

When considering markets in which rent is present the persistence in profits testing method will be unable to differentiate between the economic rent present and economic profit. In fact, this point was recognized in the earlier writings on the persistence in profits hypothesis.

> Absolute cost disadvantages refer, at base, to some factor of production that is denied the potential entrant who, but for this omitted factor, would be as efficient as established firms. Of all the possible causes of absolute cost advantages so defined, the first which comes to mind is preferred access to natural resources. Geroski, Gilbert, and Jacquemin (1990, p.38)

Although Geroski, Gilbert, and Jacquemin recognize the potential for a problem, they conclude the opportunity cost of a reservoir obviates the need to control for any absolute advantage. They cite Demsetz's (1982) study of taxicab medallions as an illustrative example how a market for assets will obviate the need to worry about these differences in absolute cost disadvantage.

There are several points worth mentioning in regard to Geroski, Gilbert, and Jacquemin's argument. First, taxicab medallions are homogenous while pools of oil and gas reservoirs are not. The heterogeneity of reservoirs combined with uncertainty surrounding the quality of a reservoir at the time of auction can lead to full rent not being collected. Porter (1995) has found that this heterogeneity appears in the empirical evidence of offshore auctions; in the wide range of bids found on a tract but also the rate of abandonment. Second, depending on the type of auction, firms may have differing amounts of information on the reservoir for auction. For instance, in the case of a drainage auction, firms with neighboring tracts to the one to be auctioned will have better information concerning the tract than firms who do not. In the case of wildcat auctions, firms may just have better geological and geophysical expertise and therefore can better determine the worth of a tract. While an auction should invoke a firm to bid its willingness to pay, Porter notes, "In an auction market with as much uncertainty as the OCS, firms have an obvious incentive to communicate, to avoid leaving too much money on the table." (p. 10) Third, the Mineral Management Service, which maintains the Outer Continental Shelf auctions, has indicated that many of the best reservoirs were auctioned off in the first several rounds of auctions held. Providing these tracts are still producing oil, firms that entered early into the auction market would have received a cost advantage over firms that entered relatively later. There are likely multiple other reasons to expect at least some firms to maintain rent from these auctions.

Therefore, in an industry where firms earn economic rents, these rents must be accounted for when attempting to estimate long-run profit. In sum, these issues with the persistence in profits testing method make identifying the portion of producer surplus attributable to profit and the portion due to economic rent impossible.

It is worth noting, that although persistence in profits is a necessary condition for market power to exist, it is not a sufficient one. Persistence in profits indicates that barriers to entry exist but it is possible for firms to receive positive profit margins over extended periods of time and yet have no market power. In the case of the U.S. offshore oil and gas production industry, firms may benefit from increases in the price of oil simply because the auction system is set up in such a way that royalties owed to the U.S. government are in large part unaffected by changes in the price of oil.

4.4 Empirical Results

To test for persistence in profit I use net income as a measure for profits which I collect from company filings with the SEC; specifically, the Center for Research in Security Prices (CRSP) database at the University of Chicago.[3] I collect GDP data from the FRED II database at the Federal Reserve Bank of St. Louis (http://research.stlouisfed.org/fred2/). The sample is quarterly and spans from 1974:1 to 2005:4. Of course, we only observe accounting profits, not economic profits, but Mueller (1990) cites Edwards, Kay, and Mayer (1987) as evidence of accounting profits, which although imperfect, offer a sufficient measure of economic profits.

I conduct the persistence in profits empirical method by first testing the time series behavior of a sample of eight energy firms'[4] profits for unit root behavior.[5] I conduct the tests on the sample average and each firm individually; in both cases I divide by GDP to control for the business cycle. I find that the time series behavior of the sample average exhibits unit root behavior. When I test the firms individually some of the time series exhibit unit roots but others do not. The results of these tests can be found in Tables 4.1-4.4.

These findings would cause the persistence in profits test to fail to reject the null of a unit root and as such imply that market power is present. Given the unique attributes of the

[3] The CRSP database was accessed at the University of Pennsylvania's WRDS website (http://wrds.wharton.upenn.edu/).

[4] The eight firms are British Petroleum, Conocophillips, Chevron, Hess, Occidental, Royal Dutch, Sunoco, and Exxon-Mobil.

[5] The specifics of these tests are included in the appendix.

oil industry, the current persistence in profits measure of market performance will lead to false conclusions about persistence in profit. I adapt the persistence in profits testing method to account for differences in average costs. Although these differences (rent) may eventually dissipate, they may not in the span of time necessary to make inference about persistence in profits.

I alter the persistence in profits method to test for market structure by taking advantage of the following theoretical result: barriers to entry drive profits to exhibit unit root behavior. Using a model of supply and demand, I illustrate how barriers to entry will lead to unit root behavior in profits, as measured by net income.

The two extreme cases—monopoly and perfect competition—exemplify this result. Economic profits will exhibit permanent shifts given permanent changes in supply and demand in the case of a monopoly; there is no mechanism to push profit toward zero in the long run because there are no other firms to compete with the monopoly. When there is competition, economic profits return to zero in the long run when a permanent change in supply or demand occurs. In sum, in the case of a monopoly, profit exhibits unit root behavior, and in the case of competition, profit is stationary.

The situation is slightly different with barriers to entry. It is possible for competition to occur within a market that contains barriers to entry as long as there is more than one firm in the market. Consider a patent—which functions as a barrier to entry by providing a specific firm with the sole rights to a low cost technology. Other firms cannot infringe upon this technology, so the cost advantage is not eliminated through competition. As long as the firm remains in operation, the rent earned by the firm displays unit root behavior in response to permanent shifts in demand and supply. The effect is identical for leases provided to firms who have the rights to low cost reservoirs. In effect the leases themselves have created barriers to entry.

But there is a method to control for rent. In a competitive industry with an upward sloping supply curve, the least efficient firm in the industry will not earn rent. Using the results of the unit root tests already conducted, tables 4.1-4.4, I examine the behavior of profit for all of the firms in the market. In theory, if one of the firm's profits rejects the null of a unit root, then the test suggests that barriers to entry have not affected the level of competition within the market. However, in practice, empirical work is subject to error; in this case, I am concerned with type one error. As such, I look for multiple rejections of the null hypothesis as an indicator of a competitive market. The results suggest that several firms reject the null of non-stationarity which implies that the barriers to entry in the U.S. offshore oil and gas market are not hindering competition.

I now compare the two sets of implications, my own and the persistence in profits hypothesis, to a procedure first used by Appelbaum (1979). Appelbaum estimates an augmented cost system to determine whether there is any mark-up present in an industry. I include Diewert's exposition of the procedure in the appendix.

While profit maximization and cost minimization represent different optimization schemes, under certain conditions regarding the production function, they result in the same technology set. The link between cost functions and profit functions is a well established result in duality theory. A theoretical treatment of this link can be found in Färe and Primont (1995), Cornes (1992), and Chambers (1988). I take advantage of this result as an empirical check of my alternative testing method.

Atkinson and Cornwell (1994) adapt Appelbaum's procedure to account for industries which are heavily regulated. Following Atkinson and Cornwell, I estimate an augmented shadow cost system to determine the competitiveness of the U.S. offshore oil industry. The details of the empirical method can be found in Chapter 3 of this document. I obtain deviations between the price of crude oil and marginal cost for a sample of 17 firms that produce crude oil and natural gas off the shores of the United States. The details of the data can be found in the appendix. In addition, I implement Cornwell, Schmidt and Sickles's (1990) method for allowing for time varying heteroskedastic error. I implement the method to obtain estimates of the deviations between the price of crude oil and marginal cost through time.

Cornwell, Schmidt and Sickles suggest the following relationship to account for time varying heteroskedasticity

$$\delta_{it} = \Omega_{i1} + \Omega_{i2}t + \Omega_{i3}t^2, \tag{4.5}$$

where omega represents firm dummies. A trend and trend squared variable are interacted with the firm dummies to account for any variation through time.

Although the sample contains only 17 firms, these firms are the larger firms within the industry. According to Hopper (1965) and Tax (1953), it is likely that the least efficient firms are contained within my sample. This sentiment also seems to be born out in observable behavior. It is often the case that smaller independents will move in and take over a reservoir after a major energy firm no longer finds it profitable for production. Several empirical papers suggest that non-integrated oil firms fair better profit-wise than their integrated counterparts: Measday (1982); Canes (1976); Rusin and Newport (1978); and Bleakley, Gee, and Hulme (1997).

Having obtained estimates of δ_{it} I now test them for unit root behavior, after determining the appropriate lag length using Hossain's (2002) Modified Akaike Information Criterion (MAIC). The results of the unit root tests vary—Table 4.5—some of the series display behavior consistent with a unit root while others are stationary.

The results of the unit root tests for the sample average of firms indicate unit root behavior at the 5% level but not at the 1% level when only a constant is included. Although I have included the results of the unit root test when both a constant and trend are included, these tests do not seem appropriate having examined Figure 3.5. This is contrary to the result obtained from the SEC data. The individual firm unit root tests produce mixed results. These results suggest that U.S. offshore production of oil and natural gas does not earn any profit and/or excess rent in the long run. Finally, my inability to reject the null for some of firms in the sample suggests that lower cost producers do earn rent.

It is apparent from Figure 3.5 that some firms have experienced different rates of return on their investments. The average firm in the sample appears to have earned some rent with the conclusion of price controls but competition appears to have arrested that. There also seems to be a change in the rate of growth in scale efficiency in 1992; there are several possible explanations for this change: the early 1990s were marked with low crude oil prices, energy firms generally experienced low profit margins in the late 1990s, and increased competition.

It seems odd however that firms have not experienced large increases in profit and/or excess rent, particularly in the last few years of the sample. There certainly have been large increases in the price of crude oil and as the general news media has pointed out, several firms have benefited greatly from these increases in price. It is of course possible that increased competition eliminated these gains or that firms simply have a better understanding of where the price of crude will be in the future but some changes in price must be unforeseeable; for instance, after the first Gulf War or Hurricanes Katrina and Rita, and yet there is very little evidence of these changes in any of the series.

4.5 Conclusion

I have suggested an alternative empirical test to the method used by the persistence in profits hypothesis; my results contradict those obtained from the persistence in profits empirical method. The persistence in profits test suggests that firms in the U.S. offshore oil and gas production industry have market power. I find this result erroneous on two counts. First, as I stated earlier, persistence in profits is a sufficient condition for barriers to entry but only a necessary condition for market power.

Second, using the same unit root tests as the persistence in profits hypothesis, my testing method indicates that barriers to entry are not inhibiting the market for U.S. offshore oil and gas production. This is a stark difference in the interpretation of the unit root tests. I believe my interpretation is more closely aligned with the actual structure of the U.S. offshore production market.

As a secondary check of the results, I invoke a readily accepted method of determining the structure of markets. From the resulting series of deviations between the price of crude oil and marginal cost it appears that at least one of the series is stationary. More importantly, it appears from the deviations that the least efficient firm in the sample earns negative economic rent over the span of the data series. These results indicate that barriers to entry have not provided a means for firms to earn excess rent in the U.S. offshore oil and gas production market.

Finally, the behavior of several of the firms' time series deviations between price and marginal cost do exhibit unit root behavior which implies these firms earn persistent rent. This result could explain the misperception surrounding the competitiveness of the industry.

Overall, this study has brought into question the persistence in profits' appropriateness in testing for market structure in an industry in which rents exist. My empirical method can be a valid alternative when data constraints eliminate the possibility of estimating a cost function.

Table 4.1: Summary Statistics

	Mean	Variance	Skew	Kurtosis	Jarque-Bera
Average	−2.928055	0.350871	-0.043701	-0.132376	0.133151
			(0.842515)	(0.767096)	(0.935592)
AHC	-0.752271	0.340290	0.280531	-0.943252	6.424076
			(0.200362)	(0.034077)	(0.040274)
BP	-0.846859	0.347373	0.464318	0.464318	9.312869
			(0.034053)	(0.034678)	(0.009500)
COP	-0.747793	0.340557	0.348149	-0.981064	7.719036
			(0.112021)	(0.027516)	(0.021078)
CVX	-0.909727	0.365269	0.458980	-0.936953	9.176163
			(0.036164)	(0.035290)	(0.010172)
OXY	-0.921085	0.800123	-4.983253	43.920161	10817.662628
			(0.000000)	(0.000000)	(0.000000)
RD	-0.708363	0.387160	0.188899	-1.082594	6.957172
			(0.390449)	(0.015428)	(0.030851)
SUN	-0.899867	0.387332	0.426401	-1.047031	9.725566
			(0.051611)	(0.018657)	(0.007729)
XOM	-0.726937	0.402436	0.567473	-0.751934	9.885375
			(0.009589)	(0.091155)	(0.007135)

Table 4.2: KPSS and Ng-Perron tests

	η_μ	η_τ	MZ_α	MZ_T
Average	2.618	0.390	-5.71878e-04	0.23404
AHC	2.211	0.389	-5.11330e-06	0.16937
BP	3.187	0.756	-5.06599e-08	0.03507
COP	2.597	0.516	-1.67116e-07	0.03578
CVX	3.192	0.700	-3.75868e-08	0.02109
OXY	2.834	0.285	-2.13766e-07	0.02379
RD	NA	NA	-6.32460e-08	0.03525
SUN	3.226	0.787	-6.21388e-06	0.14879
XOM	2.120	0.471	-2.43370e-06	0.08689
5%	0.463	0.146	-17.3	-2.91

Table 4.3: Elliot, Rothenberg and Stock Tests

	$DFGLS_\tau$	$DFGLS_\mu$	P_τ	P_μ
Average	-0.463	-1.837	27.421	15.985
AHC	-0.042	-1.771	126.282	27.699
BP	-1.333	-2.070	7.890	8.301
COP	-1.622	-1.895	5.769	9.321
CVX	-2.679	-3.844	1.897	1.850
OXY	-3.563	-4.017	1.208	1.940
RD	-1.319	-2.373	7.946	6.683
SUN	0.068	-2.723	72.580	37.803
XOM	-0.285	-1.988	24.674	11.613
5%	-1.95	-2.73	3.26	4.65

Table 4.4: Perron's test for a structural break

	IO1	IO2	AO
Average	-2.07362	-3.28959	-2.93493
AHC	-4.34025	-3.70644	-2.36649
BP	-3.25456	-4.25913	-3.12975
COP	-3.57655	-4.38134	-3.46739
CVX	-2.73466	-2.39701	-2.87330
OXY	-10.85040	-95.76854	-11.77414
RD	-9.15912	-9.17732	-4.62605
SUN	-2.37939	-2.93493	-3.29011
XOM	-3.78310	-4.66214	-3.63629
5%	-4.80	-5.08	-4.65

Table 4.5: Phillips-Perron and KPSS tests

	with constant		with trend	
	KPSS: η_μ	Phillips-Perron	KPSS: η_τ	Phillips-Perron
Average	0.624	-0.001	0.393	0.335
Firm 1	0.393	-1.527	0.718	-0.434
Firm 2	0.570	-0.249	0.718	2.347
Firm 3	0.561	-2.308	0.718	2.815
Firm 4	1.430	6.953	0.392	-0.631
Firm 5	1.318	4.676	0.392	-0.063
Firm 6	1.575	-41.475	0.718	-0.573
Firm 7	1.523	11.889	0.718	-0.163
Firm 8	0.745	0.553	0.718	-0.997
Firm 9	1.153	2.933	0.718	-1.576
Firm 10	0.566	-0.264	0.718	-1.594
Firm 11	0.938	1.519	0.718	-2.330
Firm 12	0.497	-2.116	0.718	-0.771
Firm 13	0.578	-0.213	0.718	0.166
Firm 14	0.519	-0.488	0.718	2.375
Firm 15	1.343	-6.222	0.718	-2.158
Firm 16	1.349	5.154	0.392	1.127
Firm 17	0.398	-1.620	0.718	1.150
5%	0.463	-2.963	0.146	-3.567
1%	0.739	-3.666	0.216	-4.295

Chapter 5

The Windfall Profit Tax

5.1 Introduction

With the recent 2005-2008 spike in the price of crude oil, members of both Congress and the media have called for reinstating the windfall profit tax. Initially enacted from 1980-1988, the title of the tax is a misnomer. The tax—an excise tax—was based on the difference between the price of crude oil and a Congressional statutory base price. Hearings have taken place in both the 109^{th} and 110^{th} Congresses in regard to imposing either a tax, a reduction or elimination of established incentives, or some combination of the two. The desire for punitive measures to be taken against the oil industry has also been echoed by President Obama although at the time of this writing his administration's position is unclear. Supporters of the tax have suggested that the rise in the price of oil provides a "windfall" to energy firms. Others such as The American Petroleum Institute claim that the windfall profit tax punishes oil firms when oil prices are high but does nothing to help them when prices are low. Concurrent with the rise in the price of crude oil has been an ongoing discussion about U.S. dependency on foreign oil. Some researchers have questioned whether the windfall profit tax encouraged companies to invest outside of the United States.

Although some research has been conducted on the windfall profit tax, the short duration of tax enactment, 1980-1988, and the designed temporary nature of the tax has left the matter under-investigated by economists. The resurgence of demand for additional regulation on the oil industry begs for a closer look into the windfall profit tax and the effects it has had on the industry.

Figure 5.1 displays the change in reserve additions in the U.S. and abroad for a sample of firms; it is clear from the figure that there was a significant shift from domestic reserve additions to foreign. While the tax undoubtedly lowered U.S. production and increased the United States' dependence on foreign oil, the magnitude of the shift from domestic to foreign production is uncertain.

I propose to test the effect of the implementation of the windfall profit tax on indicators of U.S. development, using a difference in differences analysis of company data to determine the tax's influence. By examining the windfall profit tax on a microeconomic level, using corporate data—company production, firm reserve additions, and expenditures on exploration and development—I offer a detailed picture of the effect of the tax.

An additional advantage of using corporate datum is that it provides the actual amount of windfall tax paid by each firm, the data accounts for different types of oil produced and the varying tax rates faced by each firm. Corporate data then avoids any potential pitfalls created when trying to account for different tax rates in aggregate data sets. For example, the amount of the windfall profit tax owed varied depending on whether a firm was a major or independent producer and by which tier the oil being produced was classified as; in addition, several categories of oil were not taxed at all: state and local government oil, oil owned by Native American Indian Tribes, charitable medical and educational institutions, a large portion of new oil produced in Alaska, and front-end tertiary oil[1] were all excluded from the tax.

5.2 Overview of the tax

The U.S. oil and gas industry has been subject to government regulations almost since its inception. Bradley (1996) has written a detailed account of the U.S. government's regulatory involvement in the oil and natural gas industry. Bradley produces numerous accounts of misallocations of resources due to these regulatory interferences. When specifically considering

[1] Tertiary oil projects involve heating the reservoir to enhance recovery, e.g., steam injection.

the windfall profit tax, Lazzari (1990) has produced a thorough structural overview of the tax. Because these resources are available, I will only touch on the necessary background issues for my analysis.

It is important to frame the windfall profit tax in its historical context by recognizing that it was preceded by a more heavily regulated environment. This environment, marked by President Richard Nixon's price controls, holds special importance to our discussion because it was the elimination of the price controls that inspired the windfall profit tax. Congress presumed that the end of price controls would generate exorbitant profits for energy companies. In an effort to capture these expected profit windfalls, the tax was instituted in 1980 as a means of recouping what was considered undeserved profits accruing to energy companies.

Lazzari writes at the time of the tax enactment the Congressional record shows that Congress also was concerned with distributional effects, the industry's low effective marginal tax rate, and the general need for revenue. Increases in firm profits due to the rise in the price of oil in the early 1970s were viewed by policymakers as an undeserved windfall for the industry, transferring wealth from consumers to producers. The oil industry's lower effective marginal tax rate had generated a feeling among some members of Congress that the industry had not been contributing its fair share of the tax burden. Finally, in 1976 the U.S. budget deficit had reached 4% of GNP and the Congress was looking for new sources of revenue.

Although its name contained the word profit, in reality the windfall profit tax was an excise tax. The tax was calculated by taking the difference between the retail price of a barrel of crude oil and the 1979 statutory base price. Initially established under price controls, the base price was estimated on what was perceived to be the cost of bringing oil to market. The base price was adjusted quarterly to account for inflation and state severance taxes. The only portion of the windfall profit tax legislation actually related to profit limited the tax to not exceed 90% of a firm's net income.

Table 5.1: Windfall Profit Tax by Tier

Tier	Tax Bracket	Average Base Price/bbl for 1980
Tier I	70% Majors 50% Independents	$12.81
Tier II	60% Majors 40% Independents	$15.20
Tier III	30% heavy oil and incremental tertiary 22.5% for newly discovered oil	$16.55

The tax was levied only on U.S. production but the tax burden was not distributed uniformly among U.S. oil producers. Taxed oil fell into three different tiers which were determined by the following characteristics: the age of the well that produced the crude, the type of crude, and the daily flow of production. To encourage the expansion of the domestic oil supply new oil was taxed less. Eventually the Economic Recovery Act of 1981 altered the structure of the tax by giving royalty owners a tax credit, eliminating any tax on stripper oil[2] producers and lowering the tax rate on newly discovered oil. Table 5.1 illustrates the breakdown of the tax structure.

Tier I was composed of wells producing while under price controls. Tier II included stripper wells and the Naval Petroleum Reserve production. Tier III was composed of heavy oil[3], incremental tertiary oil, and newly discovered oil. The baseline price increased at the rate of inflation, measured by the GNP deflator, for tiers I and II. Tier III increased an additional 2% per year.

[2]Stripper oil is classified as oil coming from reservoirs producing less than 15 barrels a day.

[3]Heavy oil is oil that has an API gravity of less than 22 degrees.

When levied, the windfall profit tax was intended to be temporary and was scheduled to begin phasing out in December 1987 contingent on meeting the revenue goal of $227.3 billion; otherwise, the phase-out was to begin no later than December 1990. The tax was scheduled to phase-out at a rate of 3% per month over 33 months. When the price of crude fell in the mid-1980s, the revenues generated from the windfall profit tax ceased, yet oil producers were obligated to continue disclosing their financials despite having no taxable income. Over the next few years both the federal government and producers viewed the tax as an administrative burden. As a consequence, the tax was repealed in 1988.

5.3 Method and Empirical Results

Before proceeding to my own method, I review the studies that have been conducted with regard to windfall profit tax. As stated in my introduction, there has been little work done on the windfall profit tax. Of the studies I have found, only two have made attempts to determine the importance of the windfall profit tax.

Lazzari says the windfall profit tax "reduced domestic oil production from between 3 and 6 percent, reservoirs and increased oil imports from between 8 and 16 percent." (1990, p. i) But Lazzari makes certain assumptions about the flexibility of the oil industry supply curve. Specifically, Lazzari assumes an elasticity of supply in the range of one-half to one to derive these estimates of the effects of the tax. Additionally, Lazzari assumes that because energy firms are competitive, their marginal cost equals the price of crude oil. This assumption does not hold in nonrenewable resource industries since in these markets it is necessary to account for rent.[4] Under the circumstances just described, it is necessary to account for cost when trying to determine how much of the change in production and imports can be attributable to the windfall profit tax. As any microeconomic text will state, the demand for a good depends on its substitute; in this case, foreign oil reserves are a substitute for domestic oil reserves. Without including costs, Lazzari implicitly makes the assumption that the cost of

[4]Rent is a payment to the owner of a resource in excess of what is required for its use.

production from outside the United States has changed identically to the cost of domestic production.

Figure 5.1 illustrates the difference in U.S. and foreign finding costs for a group of international energy firms. The figure makes clear that the rates of change between U.S. and foreign finding costs vary over the time period in which the tax was in effect.

Unlike Lazzari, Ferry (1993) conducts an empirical experiment to determine the general response of U.S. oil reserves and production to regulation. Ferry examines how different fiscal policies affect aggregates of domestic discovery and production. He estimates the windfall profit tax delayed the development of 2.4 billion barrels of reserves. Examining the effect of the windfall profit tax on the individual components of reserve replacement, Ferry estimates that the tax postponed 126 million barrels in new field discoveries, 31 million barrels in old field discoveries, 45 million barrels in extensions, and 3.3 billion barrels in revisions. Ferry also estimates that the windfall profit tax decreased production by 1.1 billion barrels. I have included a section in the appendix that discusses Ferry's method for deriving these estimates.

Ferry's method of determining the importance of the windfall profit tax overlooks some important details. First, reserves and production may react with a lag to changes in firm behavior and therefore may not represent correct indicators of the effect of the tax given the terminal date of the data used in this study. Second, Ferry, like Lazzari, does not account for international oil production markets. Third, the tax was not levied uniformly on all domestic production, which may also bias his results. Fourth, although not an oversight, his analysis is based on data covering 1947-1986, which would suggest that the analysis needs to be updated. I expand on a few of these points below.

Ferry assumes that cost-minimizing firms only took production costs of directly taxed inputs into consideration for their optimization problem. This method assumes the costs of substitute inputs, foreign reserves, and other latent mitigating factors remained constant. This omission may bias estimates of the effect of the windfall profit tax.

Lucke and Toder (1987) discuss the burden of the windfall profit tax on U.S. producers of crude oil. The authors point out that differences in the tax burden exist because of the different types of oil produced, the type of firm that produced the oil, the age of the deposit and so forth. This raises the question to whether an accurate picture of the effect of the windfall profit tax on domestic oil production can be obtained from aggregated data. For instance, independents were taxed at lower rates than majors.[5] Therefore, reservoirs which were cost prohibitive to majors under the windfall profit tax might not have been cost prohibitive for independents. Majors could then sell reserves-in-place to independents who in-turn could produce the reserves cost effectively. Examining aggregate data only in the previously described circumstance would mask this effect.

Another concern is that Ferry's study focuses on reserve replacement. While technology has improved enough such that reserve replacement has become a more successful undertaking, an element of chance remains involved.

To correct for the last concern, I include additional indicators besides reserve replacement to flesh out the effect of the tax. I can eliminate the element of luck within the empirical results by including investment expenditures as a dependent variable.

To account for differing production costs faced by international energy firms, I estimate their marginal costs using two separate shadow cost functions for international energy firms: one for their U.S. production, and one for the remainder of their production. I estimate a shadow cost function instead of a simple cost function because the shadow cost function is especially suited for industries that are heavily regulated.[6] It is my hypothesis that the omission of U.S. and foreign costs in previous studies have misrepresented the importance of the windfall profit tax.

The data I use to estimate the cost function and conduct the difference in differences experiment are collected by the Energy Information Administration (the statistical arm of

[5]The difference between majors and independents being, independents are not vertically integrated. In our case, they have no downstream production.

[6]The details of the cost function and the data used to estimate it can be seen in Littlefield (2008).

the Department of Energy). The data set is a panel of annual data containing 50 energy firms[7] with annual observations spanning the years 1977 to 2006. Additional details pertaining to the data set can be found in the appendix. Because many of the firms did not exist under both regulatory regimes, I have eliminated all but 17 firms. Firm specific data are confidential and protected by the Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA) as well are any empirical results that may compromise a firm's competitive strategy.

The cost functions for both U.S. and foreign production satisfy the necessary conditions for their validity, i.e. concavity and monotonicity. Once I have obtained estimates of each energy firm's marginal cost, I then include these estimates to control for costs in a natural experiment to determine the effect of the windfall profit tax.

Beyond marginal cost, I include the following additional control variables within the difference in differences analysis: the price of oil, the fraction of firm production to total reserves, year dummies, lags of the regressand, and each firm's corporate income tax paid. I use the composite refiners acquisition price as a measure of the price of crude oil. I use each firm's annual output of barrels of oil equivalent for production. As a measure of reserves I use each firm's total proved oil equivalent in reserves. All of the data are collected from the EIA. With the exception of the price of crude, the data are collected from the Financial Reporting System database.

I regress the following annual indicators on the independent variables listed above: firm production, exploratory wells drilled, development wells drilled, firm production expenditures, firm land acquisition expenditures, firm geological and geophysical expenditures, firm exploration expenditures, and firm development expenditures. I also divide changes in reserve additions into the following groups: revisions, improved recovery, extensions and discoveries, and sales of Minerals-in-Place.

[7]The sample includes 47 U.S. based firms and three foreign owned subsidiaries: BP America, Shell Oil, and Total Holdings USA.

All physical quantities of oil and oil equivalents are measured in millions of barrels of oil equivalent. I have converted all monetary values into real dollars by using the GDP deflator. Expenditures are measured in millions of dollars. Wells drilled are simply the annual number of wells drilled. Both the price of oil and marginal cost are measured in dollars per million barrels. Likewise, taxes are also measured in millions of dollars.

I estimate the following equation to determine the effect of the windfall profit tax on various investment indicators, production, and reserve replacement:

$$\begin{aligned}\Delta y_{it} = {} & \beta_0 + \textstyle\sum_{j=1}^{2} \beta_j \Delta MC_{i,t+1-j} + \sum_{j=1}^{2} \beta_{j+3} \Delta \ln PO_{i,t+1-j} + \beta_6 \Delta y_{i,t-1} \\ & + \beta_7 \Delta FRAC_{i,t} + \beta_8 \Delta WPT_{i,t} + \beta_9 \Delta INCTAX_{i,t} \\ & + \textstyle\sum_{j=1}^{T-1} \beta_{9+j} D_j \end{aligned} \tag{5.1}$$

y_{it} represents the regressand for firm i at time t for either U.S. or foreign production. MC_{it} is the marginal cost for each firm at time t. PO_t is the price of oil. $FRAC_{it}$ is the ratio of each firm's production to reserves for period t. I include time dummies, D_j, for each period and a lag of the regressand. I also include the differenced corporate income taxes paid by each firm. The coefficient for WPT is the coefficient of interest and may be interpreted as the difference in differences estimator. WPT can be thought of as two dummy variables interacted with the windfall profit tax faced by a firm. The first dummy takes the value of one if the firm is within the United States and zero otherwise. The second dummy variable takes the value of one during the time period of the windfall profit tax and zero otherwise.

I tested the above equations for both serial correlation and heteroskedasticity. Heteroskedasticity does appear to be a problem; as such, I have estimated these equations with a heteroskedasticity/serial correlation consistent covariance matrix.

The estimation results can be seen in Tables 5.2 through 5.4. Table 5.2 exhibits the results of regressing aggregated data on the independent variables in equation (5.1). Table

5.3 presents results from a further disaggregation of reserve replacement. The dependent variables in this case are: revisions, improved recovery, extensions and discoveries, and net purchases of Minerals-in-Place. Table 5.4 displays the response of firm expenditures.

Although my focus is on the importance of the windfall profit tax, it is worth noting other aspects of the empirical results as well. For example, marginal cost is statistically significant in all but two of the regressions run. This is significant because it is my contention that the absence of marginal cost in previous studies biased their results. When the coefficient for marginal cost is statistically significant, the sign of the coefficient is also what I would expect according to theory. Of the two regressions in which marginal cost is not statistically significant, the first contains production as the regressand. One possible reason for the lack of statistical significance for marginal cost is that a significant portion of expenditures are sunk at this stage in the production process.

When revisions is used as a regressand, marginal cost is again statistically insignificant; however, the R^2 suggests that the equation has very little explanatory power. The Energy Information Administration classifies revisions to previous estimates in the following way.

> Changes in previous estimates of proved reserves, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors. Revisions do not include changes in reserve estimates resulting from increases in proved acreage or from improved recovery techniques.

This suggests that changes in recoverable reserves should, at least in part, be related to fundamentals such as the price of crude; however, they are also estimates subject to reevaluation when additional information is available.

Examining the price of oil within the estimated equations, either the contemporaneous and/or lag effect are statistically significant for all but the following regressands: production, acquisition of land, production expenditures, revisions, extensions and discoveries, and Net

Purchases of Minerals-in-Place.[8] When the price of oil is statistically significant it also has the sign I would expect according to theory. The lack statistical significance of the price of oil on both production and production expenditures is a quizzical result. When using Land Acquisition as the regressand, the price of oil also displays what I would consider a theoretically incorrect sign, although it is not statistically significant. I believe this result is due to the long lag time between the leasing of land and production of oil from it. Firms are likely to base their leasing behavior on their expectations of the price of crude in the future. The negative effect of exploratory wells on the price of oil may be explained by substitution. Cleveland and Kaufmann (1991) point out that firms tend to increase both their exploratory and development drilling with an increase in the price of crude oil, they also tend to replace exploratory drilling with developmental drilling.

The final two control variables I include are the ratio of each firm's production to reserves and the income tax face. The fraction of production to reserves is both statistically significant and displays the sign I would expect for reserve replacement; however, the negative relationship with expenditures while not necessarily incorrect is not what I expected. The delay between expenditures and production make any contemporaneous relationship tenuous. Income taxes always appear with the sign I would expect but are often statistically insignificant. This may be due to the low effective tax rate enjoyed by the oil industry.

A few of the coefficients on the windfall profit tax are quizzical in regard to my expectations. The coefficient for exploratory wells drilled is statistically influenced by the windfall profit tax but its sign is positive which is not what I would expect. One possible cause of this result is that the windfall profit tax represents a regulatory loosening relative to price controls. A second possibility is that the temporary nature of the tax did not provide a sufficient incentive to discourage firms from exploring for the future or discovering new potential low-cost deposits. If my assumption is correct, then a permanent tax would likely generate a larger negative effect. Another possibility, which I will expand upon below, is the devel-

[8]The price of oil also has no statistical effect on revisions but as I stated earlier, I find this result to be uninformative.

opment of reserves was not affected by the windfall profit tax because of the stage at which the tax was levied in the development process.

The effect on net-purchases may help to explain the effects of the windfall profit tax under improved recovery, extensions and discoveries, as well as exploratory wells drilled. The purchase and sale of minerals-in-place would allow firms to continue to operate within the United States while avoiding the windfall profit tax. Because major energy firms faced a higher tax rate on production than relative to independent energy firms, they could find, develop, and sell proved reserves and high-cost existing reserves to independents.

My aggregation of oil and natural gas represents one potential reason for the lack of a significant effect of the windfall profit tax on development expenditures. Figure A.5 illustrates my point. There appears to be a decline in offshore natural gas development when the windfall profit tax is rescinded. Development wells increase through the end of tax enactment. These two contrary effects might be negating each other in the regression analysis.

The effect on land acquisition seems reasonable but contradicts my theory on why the windfall profit tax has had a positive influence on exploration. There is however a slight difference in exploration and acquisition. Land acquisitions represent a commitment by a firm and expenditures and effort spent on exploration occur downstream of this commitment. Thus, without any commitment, it appears firms substituted away from domestic investment; however, once a commitment was made they saw that commitment through, at least until firms sold the reserves as minerals-in-place. Finally, because the windfall profit tax is considered a production expenditure it is reasonable that the windfall profit tax has positively influenced production expenditures.

Because I am only considering a sample of companies, my results are not comparable with Ferry or Lazzari's. Therefore, to determine the economic importance of the tax, I compare the predicted changes in the regressands due to the windfall profit tax to the average of the regressand for all firms for two sets of time periods: the full span of the data set and the years in which the windfall profit tax was enacted. For example, the change in production due to the windfall profit tax is approximately 4 million BBLs of oil equivalent. Dividing this change by the average output by all firms for the time span 1980-88 implies a 0.024 percent change. It appears that regardless of which time frame is used the response of regressands are relatively unaffected by the windfall profit tax. These results can be seen in Table 5.5.

5.4 Discussion

From the results that I have obtained, the windfall profit tax did have a statistically significant effect on energy firms that produced both in the United States and abroad. My estimates suggest that the economic effect was minor. This result differs from both Lazzari and Ferry's study. I attribute this difference in the economic significance of the windfall profit tax to the inclusion of marginal cost. When considering some of the more unexpected results of my study, it seems that including a proxy for returns on investment might be appropriate; for instance, including leads of marginal cost. Although my study suggests that reestablishing the windfall profit tax or similar legislation[9] would have little effect on investment in our natural resources, there are several caveats to consider.

First, although some of the tax plans immerging from Congress have been for a temporary tax, a temporary tax that is instituted every time the price of crude oil rises will be indistinguishable from a permanent tax. It is important to note when considering the effect of the 1980-88 windfall profit tax that it was always intended to be temporary. Undoubtedly, the tax effect was smaller than if it had been considered a permanent tax.

Second, because I have not included any type of proxy to control for the political environment at the time, the above equation is likely susceptible to omitted variable bias. The decade prior to the tax enactment included a number of nationalizations of reservoirs within foreign countries. These nationalizations likely had an effect on the decision making process undertaken by firms when deciding where to invest.

[9] Several types of legislation have been discussed in Congress including income tax levy, excise tax, and repeal of special tax privileges.

The combination of these two effects suggest that my estimates of the importance of the windfall profit tax should be taken as the minimum. One possible avenue for future research would be to derive a proxy for riskiness of nationalization within a country and include a variable to control for potential benefits of exploration.

In sum, my study sheds new light on the effect of the windfall profit tax and finds that its economic impact was minor. Despite this, the government should be cautious when considering the imposition of new windfall profit tax legislation given the reservations around this study. A more reasonable approach would be to reduce the advantages the industry currently enjoys over other industries (i.e. the industry's low effective marginal tax rate) forcing the industry to compete for capital investment. The removal of the industry specific tax incentives has the advantage of forcing the oil and gas industry to compete on a level playing field with other industries and does not create the unintended consequences of sophisticated tax regulation seen during the enactment of the windfall profit tax.

Table 5.2: Difference in Differences Analysis

Independent Variable	ΔProduction	ΔExploratory Wells Drilled	ΔDevelopment Wells Drilled
$\Delta MC_{i,t}$	-0.153	-0.190***	-1.700***
	(0.132)	(0.052)	(0.392)
$\Delta MC_{i,t-1}$	-0.139	-0.142***	-1.727***
	(0.123)	(0.053)	(0.452)
ΔPO_t	0.198	-0.016	2.176**
	(0.434)	(0.261)	(0.955)
ΔPO_{t-1}	0.314	-0.517**	2.714**
	(0.359)	(0.245)	(1.244)
$\Delta y_{i,t-1}$	0.003***	-0.125	-0.210***
	(0.027)	(0.091)	(0.056)
$\Delta FRAC_{i,t}$	-0.293***	-0.157**	-0.713***
	(0.071)	(0.051)	(0.131)
$\Delta WPT_{i,t}$	-0.005	0.027**	0.066*
	(0.006)	(0.011)	(0.036)
$\Delta INCTAX$	-0.031***	-0.000	-0.022***
	(0.006)	(0.001)	(0.005)
R^2	0.540	0.127	0.239

*** significant at the 1% level

** significant at the 5% level

* significant at the 10% level

Table 5.3: Difference in Differences Analysis

Independent Variable	ΔRevisions	ΔImproved Recovery	ΔExtensions and Discoveries	ΔNet Purchases of Minerals-in-Place
$\Delta MC_{i,t}$	0.081	-0.296**	-0.216	-5.051***
	(0.330)	(0.139)	(0.214)	(0.906)
$\Delta MC_{i,t-1}$	-0.139	-0.286***	-1.363***	-1.941**
	(0.327)	(0.099)	(0.188)	(0.788)
ΔPO_t	1.237	0.815**	-0.542	-0.460
	(1.719)	(0.468)	(1.013)	(2.652)
ΔPO_{t-1}	0.3745	1.046***	0.448	-2.597*
	(1.266)	(0.308)	(0.893)	(1.451)
$\Delta y_{i,t-1}$	-0.529***	0.521***	-0.315***	-0.449***
	(0.099)	(0.062)	(0.080)	(0.109)
$\Delta FRAC_{i,t}$	-1.021***	-0.521***	-1.363***	-0.126
	(0.288)	(0.069)	(0.188)	(0.269)
$\Delta WPT_{i,t}$	0.043	0.023	0.839	-0.054**
	(0.037)	(0.010)	(0.026)	(0.023)
$\Delta INCTAX$	-0.022**	-0.002	-0.017**	-0.005
	(0.010)	(0.002)	(0.006)	(0.004)
R^2	0.319	0.317	0.213	0.411

*** significant at the 1% level

** significant at the 5% level

* significant at the 10% level

Table 5.4: Difference in Differences Analysis

Independent variable	ΔLand Acquisition Expenditures	ΔGeological and Geophysical Expenditures	ΔExploratory Expenditures ¬ G&G†	ΔDevelopment Expenditures	ΔProduction Expenditures
$\Delta MC_{i,t}$	-45.679***	-.137*	-0.976***	-2.585***	-1.287
	(7.396)	(0.077)	(0.263)	(0.962)	(0.813)
$\Delta MC_{i,t-1}$	-20.760***	-0.223***	-0.602***	-1.223***	-1.918**
	(7.144)	(0.081)	(0.226)	(0.959)	(0.794)
ΔPO_t	-7.237	0.550**	1.573**	15.486***	1.863
	(13.126)	(0.269)	(0.782)	(3.947)	(2.869)
ΔPO_{t-1}	-3.330	-0.373*	-0.721	11.925***	-0.448
	(15.755)	(0.220)	(0.765)	(3.305)	(2.262)
$\Delta y_{i,t-1}$	-0.539***	-0.239***	-0.063	-0.075	-0.010
	(0.124)	(0.085)	(0.053)	(0.054)	(0.034)
$\Delta FRAC_{i,t}$	-13.511***	-0.021	-1.373***	-3.140	-1.053**
	(5.209)	(0.072)	(0.133)	(1.969)	(0.502)
$\Delta WPT_{i,t}$	-0.333	0.034***	0.121***	-0.123	0.986***
	(0.236)	(0.011)	(0.031)	(0.086)	(0.046)
$\Delta INCTAX$	-0.180*	-0.009***	-0.024***	-0.236***	-0.250***
	(0.099)	(0.002)	(0.003)	(0.034)	(0.054)
R^2	0.460	0.333	0.322	0.617	0.705

† ¬ denotes the exclusion of G&G.

*** significant at the 1% level

** significant at the 5% level

* significant at the 10% level

Table 5.5: Relative Effects: % change due to the WPT

Variable	1977-2006	1980-1988
Production	-0.003	-0.003
Exploratory Wells Drilled	0.010	0.009
Development Wells Drilled	0.133	0.081
Land Acquisition Expenditures	-0.081	-0.072
G&G Expenditures	0.043	0.045
Exploration $\neg$ G&G expenditures	0.057	0.042
Development Expenditures	-0.020	-0.022
Production Expenditures	0.109	0.089
Revisions	0.262	0.247
Improved Recovery	0.088	0.077
Extensions and Discoveries	1.110	1.272
Net Purchases of Mineral-in-Place	-0.074	-0.076

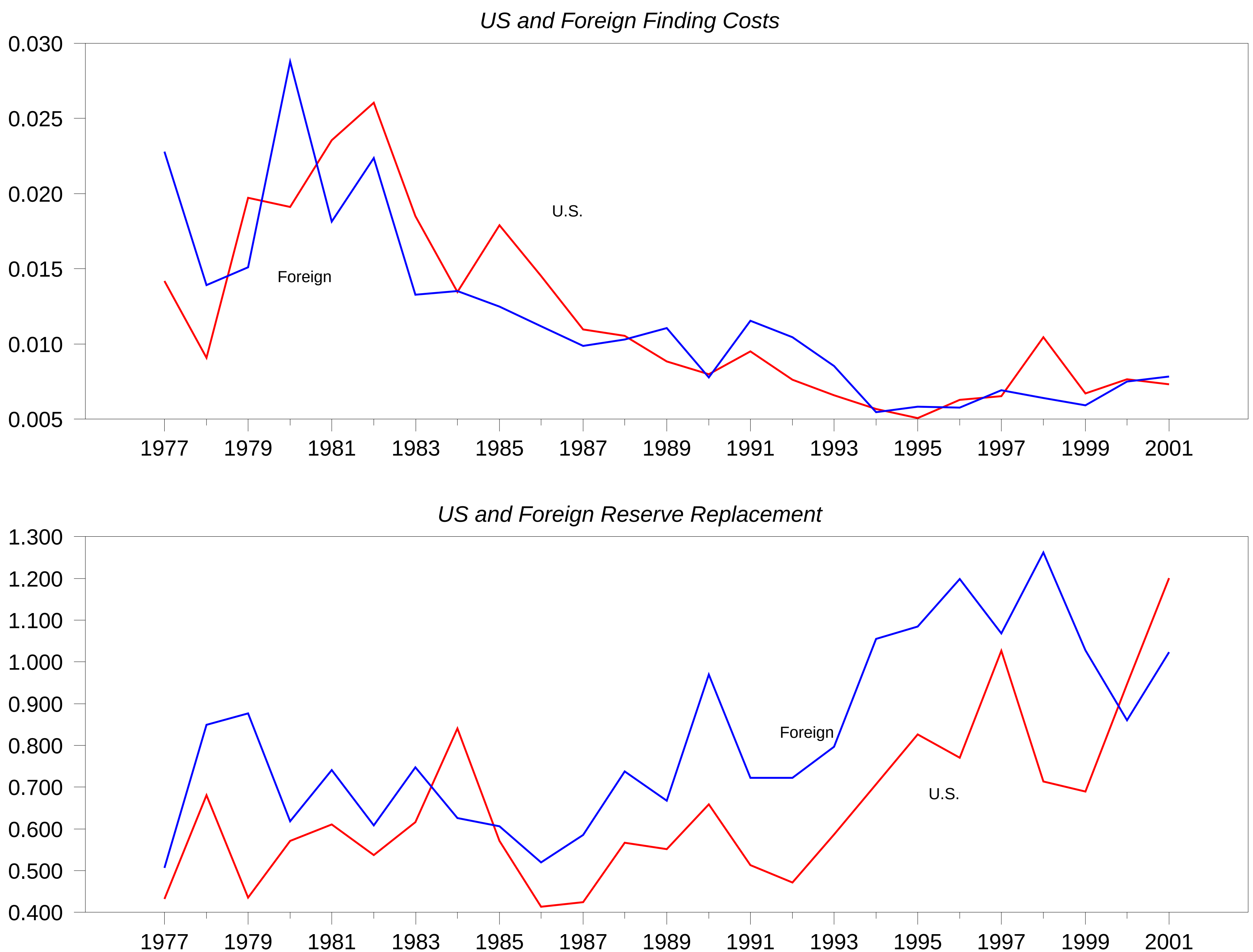


Figure 5.1: Reserve Replacement and Finding Costs

Chapter 6

Conclusion

My goals for this study were: to determine the structure of U.S. offshore oil and gas market, to develop a method of determining the structure of markets, and to determine the effect the windfall profit tax had on investment in U.S. oil and natural gas development. My results suggest that the U.S. offshore oil and gas production market is competitive and that despite the structure of offshore lease agreements, leases have done a good job extracting rent. I produced an alternative to the persistence in profits hypothesis with very different implications than those obtained from the persistence in profits method. And furthermore, the implications of my tests are more in line with results I obtained in my first chapter. Finally, my research stands in opposition from that done previously on the windfall profit tax. In contrast, my research suggests the effect the tax had on the U.S. oil and gas industry was minor.

Do Energy Companies Benefit from Volatile Oil Prices?

The research that has examined the production of U.S. offshore oil and gas has surrounded the performance of auctions. My research not only addresses auctions but also the structure of the market. In that sense, my empirical test is a dual-hypothesis. Under the null hypothesis, firms earn persistent profit and/or excess rent. This null could occur under two circumstances. One, the independence of the bonus-bid from the price of crude oil has generated long-term rent for firms in the market. Two, the U.S. offshore oil and gas production market is not competitive. Alternatively, the rejection of the null hypothesis results in both of the dual hypothesis being false.

To determine the structure of the market I examine deviations of firm marginal costs from the price of crude oil through time. To obtain these estimates I use a translog shadow cost function, building off the research of Appelbaum (1979), Atkinson and Cornwell (1994), and Cornwell, Schmidt and Sickles (1990). The deviations of the average firm at any point in time are in line with what would be expected of a competitive market. The series is stationary and is close to zero. In closing, from a U.S. energy policy standpoint these results suggest that current attitudes toward the U.S. offshore oil and gas production industry are unwarranted.

A Test for Barriers to Entry

Because the test I conduct in my first essay requires detailed information that is not always available, I have produced an alternative that does not require as much information. Although the idea behind the test is based loosely on the persistence in profits method, the implications of the test are quite different when considering the U.S. offshore oil and gas production market. The test suggests that U.S. offshore oil and gas production is competitive. But more importantly, the study provides a viable alternative to the persistence in profits method when rents are likely present.

The Windfall Profit Tax

The modest research that has been done on the windfall profit tax is not only out of date but also neglects some important details, the most significant of which appears to be neglecting to account for the cost of substitute inputs. Instead of focusing on the entire domestic market, as was done previously, I took a more disaggregated approach by focusing on firms that produced not only in the U.S. domestic market but also abroad. After including estimates of marginal cost, which I obtained from the cost function I developed in my first essay, the importance of windfall profit tax was diminished. This stands in contrast to previous claims as to the importance of the tax, which is to say, the tax had little affect on investment in and production from U.S. oil reservoirs.

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Appendix A

Financial Reporting System Data

The firm specific data I use are obtained from the Energy Information Administration. The data are contained in their Financial Reporting System database. The Energy Information Administration uses the data to produce an annual publication, "Performance Profiles." These reports give summary information about the data and can be accessed at http://www.eia.doe.gov/emeu/perfpro/. Though the data contain details on all aspects of operations—upstream and downstream—I only take advantage of the upstream portion.

The initial 1976 criterion for being included in the FRS survey included any firm which, "had at least 1 percent of either production or reserves of oil, gas, coal, or uranium in the United States or 1 percent of either refining capacity or petroleum product sales in the United States." (Energy Information Administration, 1998)

However, this criterion was changed in 1998 due to the evolution of the industry. The new criterion for inclusion in the data set is, "any U.S.-based company (or its parent company) that is publicly-traded, and accounts for 1 percent or more of U.S. production or reserves of crude oil (including natural gas liquids) or natural gas, or 1 percent or more of U.S. refining capacity or refined product sales volume." (Energy Information Administration, 1998)

The data have been scarcely used for scholarly work as data are restricted by the Confidential Information Protection and Statistical Efficiency Act of 2002 (CIPSEA). Given this restriction, below I will provide as detailed information as possible concerning the data.

The variables I use for my experiments can be seen in Tables A.1-A.2 below. The majority of the variable descriptions are taken directly from Energy Information Administration's website, http://www.eia.doe.gov/glossary/index.html. Instead of supplying simple summary statistics of the data, I include Figures A.1 through A.11. Each figure illustrates how the mean of the variable changes through time as well as blue one standard deviation bands. Within the figures the following letters denote: (F) for foreign, (O) for oil, (NG) for natural gas, and (D) for a dry hole.

To determine if offshore barriers to entry are binding in that they reduce competition in the U.S. offshore oil and gas market, I utilize the EIA's delineation of offshore and onshore data. Unfortunately, this eliminates all but 17 of the 50 firms in the sample. The data on the 17 remaining firms compose the data set I use to estimate all of the cost functions within my dissertation as well as the difference in differences estimation. The panel is unbalanced; this can be seen in Tables A.3-A.7. The number of observations drop to 9 observations per time period at the end of the sample. This drop in the number of observations is due to the merging of the firms.

Although I only have 17 firms in my sample, they tend to be the larger firms in the market. As Tax (1953) and Hopper(1965) have noted, often the largest firms are less efficient than corresponding smaller firms within an industry. Several authors have made this observation: Measday (1982), Canes (1976), Rusin and Newport (1978), and Bleakley, Gee, and Hulme (1997). It therefore seems likely that firms in this sample will be closer to the least efficient cost frontier.

The inputs I use in the cost function are similar to Sardosky's (1991). Sardosky includes drilling, geological and geophysical, and land acquired. I add production expenditures to land acquisition as a measure of the price of the resource. To generate shares for the cost function, I divide the total expenditure on each input by the total expenditure for upstream operations for a firm. To generate prices, I divide the total expenditure on each input by the best metric for a unit of input I was able to obtain in the data set. I define expenditures on exploration—minus geological and geophysical—and development per well per the number of reserves as a measure of the price of drilling. This can be seen in Equation (A.1) below. I define the price of geological and geophysical effort as expenditures on geological and geophysical activities divided by the total number of net developed and undeveloped acres possessed by a firm. Finally, I define the price of the resource itself as the sum of two ratios. First, the annual expenditures on the acquisition of lease rights are divided by the of number of reserves—barrels of oil equivalent—generated in the same year. Second, production expenditures are divided by the number of barrels of oil equivalent produced.

$$\begin{aligned} p_{drilling} \equiv & \left(\frac{\text{expenditures on exploration and development excluding G\&G}}{\text{total number of exploratory and development wells drilled}}\right) \\ & \times \left(\frac{1}{\text{reserves}}\right), \end{aligned} \tag{A.1}$$

$$p_{G\&G} \equiv \left(\frac{\text{G\&G expenditures}}{\text{net acreage}}\right), \tag{A.2}$$

and

$$p_{resource} \equiv \left(\frac{\text{property acquisition costs}}{\text{reserves}}\right) + \left(\frac{\text{production expenditures}}{\text{production}}\right). \tag{A.3}$$

Table A.1: FRS Data Descriptions

Variable	Description
Y	I use millions of barrels of oil equivalent as a measure of each firms output. Natural gas can be converted to barrels of oil equivalent at a rate of 0.178 barrels per thousand cubic feet.
RESRV	Proved Energy Reserves: Estimated quantities of energy sources that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions. The location, quantity, and grade of the energy source are usually considered to be well established in such reserves.
ACR	Acreage: An area, measured in acres, that is subject to ownership or control by those holding total or fractional shares of working interests. Acreage is considered developed when development has been completed. A distinction may be made between ”gross” acreage and ”net” acreage: Gross. All acreage covered by any working interest, regardless of the percentage of ownership in the interest. Net. Gross acreage adjusted to reflect the percentage of ownership in the working interest in the acreage.
EXPL	Exploration Expenditures: Costs of locating oil and gas deposits, including the costs of retaining and carrying undeveloped property, geological and geophysical costs, and the costs of drilling and equipping exploratory wells.
G&G	Geological and Geophysical Expenditures: Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies.
DEVL	Development Expenditures: Costs of developmental wells, facilities and support equipment used to access and prepare oil and gas deposits for production.
PROD	Production Expenditures: The costs of extracting oil and gas from oil and gas deposits.
TC	Total Upstream Expenditures are composed of: expenditures on acreage acquisition, exploration expenditures, development expenditures, and production expenditures.
Exploratory wells drilled	Exploratory. Drilling to locate probable mineral deposits or to establish the nature of geological structures; such wells may not be capable of production if minerals are discovered.
Development wells drilled	Developmental. Drilling to delineate the boundaries of a known mineral deposit to enhance the productive capacity of the producing mineral property.

Table A.2: FRS Data Descriptions

Variable	Description
Dry well drilled	Dry [well] hole: An exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
REVSN	Changes in previous estimates of proved reserves, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors. Revisions do not include changes in reserve estimates resulting from increases in proved acreage or from improved recovery techniques.
IMPRVD	Improved Recovery: Reserve additions resulting from the application of improved recovery techniques.
EXTNSN	Extensions and Discoveries: Reserve additions that result from the extension of previously discovered reservoirs or the discovery of new fields or reservoirs.
NETPURCH	Purchases or Sales of Minerals-in-Place. Increase or decrease in the estimated quantity of reserves resulting from the purchase or sale of mineral rights in land with known proved reserves.
WPT	The Windfall Profit Tax paid by corporations
INCTAX	Corporate taxes paid on all income profits. This does not include the WPT.

Source of Definitions: Energy Information Administration, found at http://www.eia.doe.gov/glossary/index.html

Table A.3: FRS Observations per Period

	U.S. Domestic					Foreign				
	REVSN	IMPRVD	NETPURCH	EXTNSN	RESRV	REVSN	IMPRVD	NETPURCH	EXTNSN	RESRV
1977	17	17	17	17	17	16	16	16	16	16
1978	17	17	17	17	17	16	16	16	16	16
1979	17	17	17	17	17	16	16	16	16	16
1980	17	17	17	17	17	16	16	16	16	16
1981	17	17	17	17	17	17	17	17	17	17
1982	17	17	17	17	17	16	16	16	16	16
1983	17	17	17	17	17	16	16	16	16	16
1984	17	17	17	17	17	16	16	16	16	16
1985	17	17	17	17	17	16	16	16	16	16
1986	17	17	17	17	17	17	17	17	17	17
1987	17	17	17	17	17	17	17	17	17	17
1988	17	17	17	17	17	16	16	16	16	16
1989	17	17	17	17	17	16	16	16	16	16
1990	17	17	17	17	17	16	16	16	16	16
1991	17	17	17	17	17	16	16	16	16	16
1992	17	17	17	17	17	17	17	17	17	17
1993	17	17	17	17	17	17	17	17	17	17
1994	17	17	17	17	17	17	17	17	17	17
1995	17	17	17	17	17	16	16	16	16	16
1996	17	17	17	17	17	16	16	16	16	16
1997	17	17	17	17	17	16	16	16	16	16
1998	17	17	17	17	17	16	16	16	16	16
1999	16	16	17	16	16	16	16	16	16	16
2000	14	14	16	14	13	13	13	13	13	13
2001	11	11	16	11	11	11	11	11	11	11
2002	11	11	16	11	11	11	11	11	11	11
2003	10	10	16	10	10	10	10	10	10	10
2004	10	10	16	10	10	10	10	10	10	10
2005	10	10	16	10	10	10	10	10	10	10
2006	9	9	16	9	9	9	9	9	9	9

Table A.4: FRS Observations per Period

	U.S. Domsetic					Foreign				
	ACR	EXPL¬G&G	G&G	DEVL	PROD	ACR	EXPL¬G&G	G&G	DEVL	PROD
1977	17	17	17	17	17	16	16	16	16	17
1978	17	17	17	17	17	16	16	16	16	17
1979	17	17	17	17	17	16	16	16	16	17
1980	17	17	17	17	17	16	16	16	16	17
1981	17	17	17	17	17	17	17	17	17	17
1982	17	17	17	17	17	16	16	16	16	16
1983	17	17	17	17	17	16	16	16	16	16
1984	17	17	17	17	17	16	16	16	16	16
1985	17	17	17	17	17	17	17	17	17	17
1986	17	17	17	17	17	17	17	17	17	17
1987	17	17	17	17	17	16	16	16	16	16
1988	17	17	17	17	17	16	16	16	16	16
1989	17	17	17	17	17	16	16	16	16	16
1990	17	17	17	17	17	16	16	16	16	16
1991	17	17	17	17	17	16	16	16	16	16
1992	17	17	17	17	17	16	16	16	16	16
1993	17	17	17	17	17	16	16	16	16	16
1994	17	17	17	17	17	17	17	17	17	17
1995	17	17	17	17	17	16	17	17	16	16
1996	17	17	17	17	17	16	17	17	16	16
1997	17	17	17	17	17	16	17	17	16	16
1998	17	17	17	17	17	16	17	17	16	16
1999	16	16	16	16	16	16	16	16	16	16
2000	13	13	13	13	13	13	13	13	13	13
2001	11	11	11	11	11	11	11	11	11	11
2002	11	11	11	11	11	11	11	11	11	11
2003	10	10	10	10	10	10	10	10	10	10
2004	10	10	10	10	10	10	10	10	10	10
2005	10	10	10	10	10	10	10	10	10	10
2006	9	9	9	9	9	9	9	9	9	9

Table A.5: FRS Observations per Period

	U.S. Domestic						Foreign				
	Y	NETEXPL	NETDEVL	TC	INCTAX	WPT	Y	NETEXPL	NETDEVL	TC	INCTAX
1977	17	17	17	17	17	17	16	16	16	17	17
1978	17	17	17	17	17	17	16	16	16	17	17
1979	17	17	17	17	17	17	16	16	16	17	17
1980	17	17	17	17	17	17	16	16	16	17	17
1981	17	17	17	17	17	17	17	17	17	17	17
1982	17	17	17	17	17	17	16	16	16	16	17
1983	17	17	17	17	17	17	16	16	16	16	17
1984	17	17	17	17	17	17	16	16	16	16	17
1985	17	17	17	17	17	17	16	17	17	17	17
1986	17	17	17	17	17	17	17	17	17	17	17
1987	17	17	17	17	17	17	17	16	16	16	17
1988	17	17	17	17	17	17	16	16	16	16	17
1989	17	17	17	17	17	17	16	16	16	16	17
1990	17	17	17	17	17	17	16	16	16	16	17
1991	17	17	17	17	17	17	16	16	16	16	17
1992	17	17	17	17	17	17	17	17	16	16	17
1993	17	17	17	17	17	17	17	17	16	16	17
1994	17	17	17	17	17	17	17	17	17	17	17
1995	17	17	17	17	17	17	16	17	16	17	17
1996	17	17	17	17	17	17	16	17	16	17	17
1997	17	17	17	17	17	17	16	17	16	17	17
1998	17	17	17	17	17	17	16	17	16	17	17
1999	16	16	16	16	16	16	16	16	16	16	16
2000	13	13	13	13	14	14	13	13	13	13	14
2001	11	11	11	11	11	11	11	11	11	11	11
2002	11	11	11	11	11	11	11	11	11	11	11
2003	10	10	10	10	10	10	10	10	10	10	10
2004	10	10	10	10	10	10	10	10	10	10	10
2005	10	10	10	10	10	10	10	10	10	10	10
2006	9	9	9	9	9	9	9	9	9	9	9

Table A.6: FRS Observations per Period

	U.S. Offshore									
	ACR	EXPLR¬G&G	G&G	DEVLP	PROD	TC	RESRVO	PRODO	RESRVNG	PRODNG
1977	17	17	17	17	17	17	15	15	15	15
1978	17	17	17	17	17	17	15	15	15	15
1979	17	17	17	17	17	17	16	16	16	16
1980	17	17	17	17	17	17	17	17	17	17
1981	17	17	17	17	17	17	17	17	17	17
1982	17	17	17	17	17	17	17	17	17	17
1983	17	17	17	17	17	17	17	17	17	17
1984	17	17	17	17	17	17	17	17	17	17
1985	17	17	17	17	17	17	17	17	17	17
1986	17	17	17	17	17	17	17	17	17	17
1987	17	17	17	17	17	17	17	17	17	17
1988	17	17	17	17	17	17	17	17	17	17
1989	17	17	17	17	17	17	17	17	17	17
1990	17	17	17	17	17	17	17	17	17	17
1991	17	17	17	17	17	17	17	17	17	17
1992	17	17	17	17	17	17	17	17	17	17
1993	17	17	17	17	17	17	17	17	17	17
1994	17	17	17	17	17	17	17	17	17	17
1995	17	17	17	17	17	17	17	17	17	17
1996	17	17	17	17	17	17	17	17	17	17
1997	17	17	17	17	17	17	17	17	17	17
1998	17	17	17	17	17	17	17	17	17	17
1999	16	16	16	16	16	16	16	16	16	16
2000	14	14	14	14	14	14	14	14	14	14
2001	11	11	11	11	11	11	11	11	11	11
2002	11	11	11	11	11	11	11	11	11	11
2003	10	10	10	10	10	10	10	10	10	10
2004	10	10	10	10	10	10	10	10	10	10
2005	10	10	10	10	10	10	10	10	10	10
2006	9	9	9	9	9	9	9	9	9	9

Table A.7: FRS Observations per Period

	U.S. Offshore									
	GROSS ACREAGE		NET ACREAGE		EXPLORATORY			DEVELOPMENT		
	UNDEVACR	DEVACR	UNDEVACR	DEVACR	DRYWELL	OILWELL	GASWELL	DRYWELL	OILWELL	GASWELL
1977	17	17	17	17	17	16	16	16	16	16
1978	17	17	17	17	17	16	16	16	16	16
1979	17	17	17	17	17	17	17	17	17	17
1980	17	17	17	17	17	17	17	17	17	17
1981	17	17	17	17	17	17	17	17	17	17
1982	17	17	17	17	17	17	17	17	17	17
1983	17	17	17	17	17	17	17	17	17	17
1984	17	17	17	17	17	17	17	17	17	17
1985	17	17	17	17	17	17	17	17	17	17
1986	17	17	17	17	17	17	17	17	17	17
1987	17	17	17	17	17	17	17	17	17	17
1988	17	17	17	17	17	17	17	17	17	17
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1992	17	17	17	17	17	17	17	17	17	17
1993	17	17	17	17	17	17	17	17	17	17
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1996	17	17	17	17	17	17	17	17	17	17
1997	17	17	17	17	17	17	17	17	17	17
1998	17	17	17	17	17	17	17	17	17	17
1999	16	16	16	16	16	16	16	16	16	16
2000	14	14	14	14	14	14	14	14	14	14
2001	11	11	11	11	11	11	11	11	11	11
2002	11	11	11	11	11	11	11	11	11	11
2003	10	10	10	10	10	10	10	10	10	10
2004	10	10	10	10	10	10	10	10	10	10
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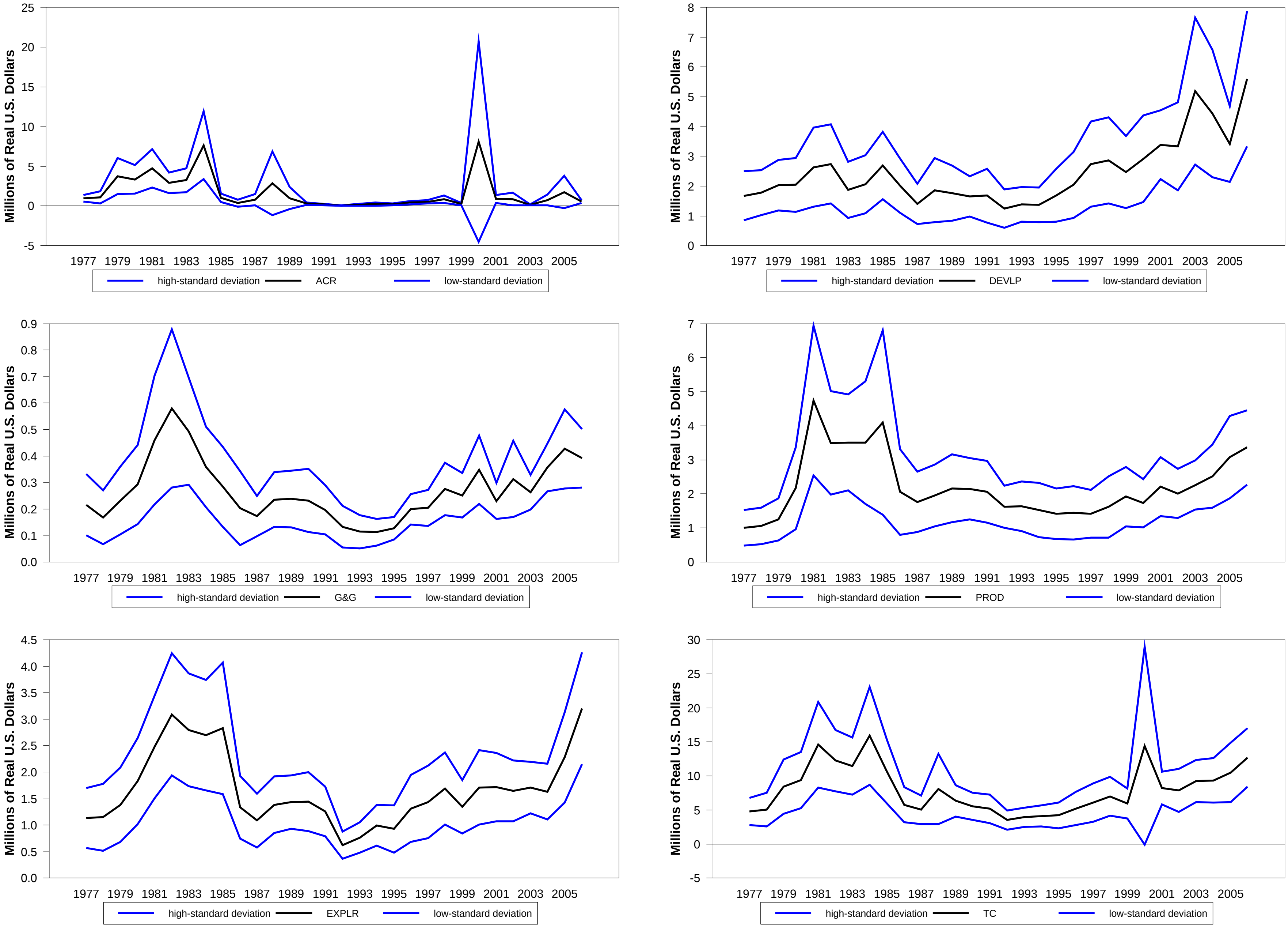


Figure A.1: Offshore Expenditures

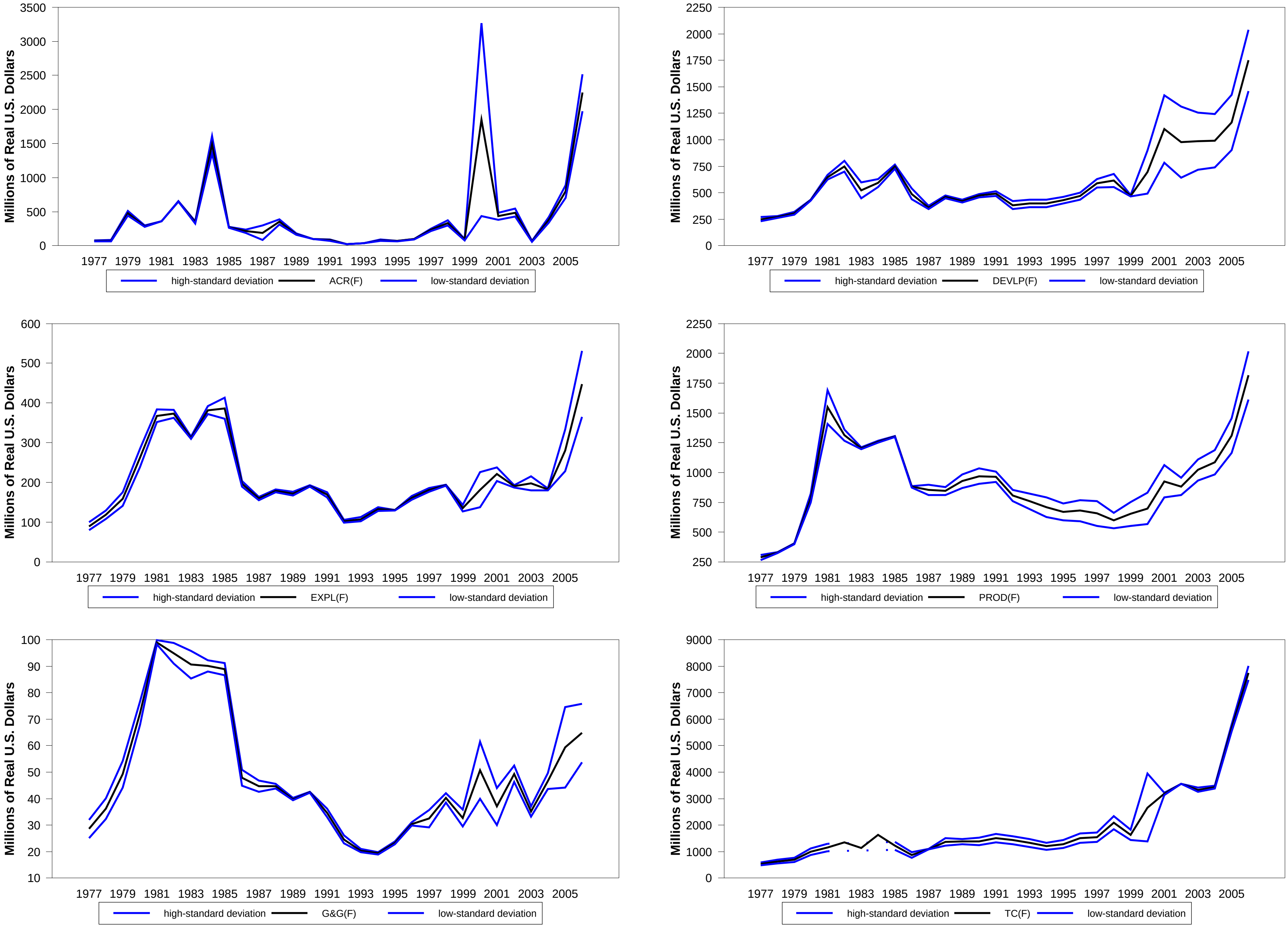
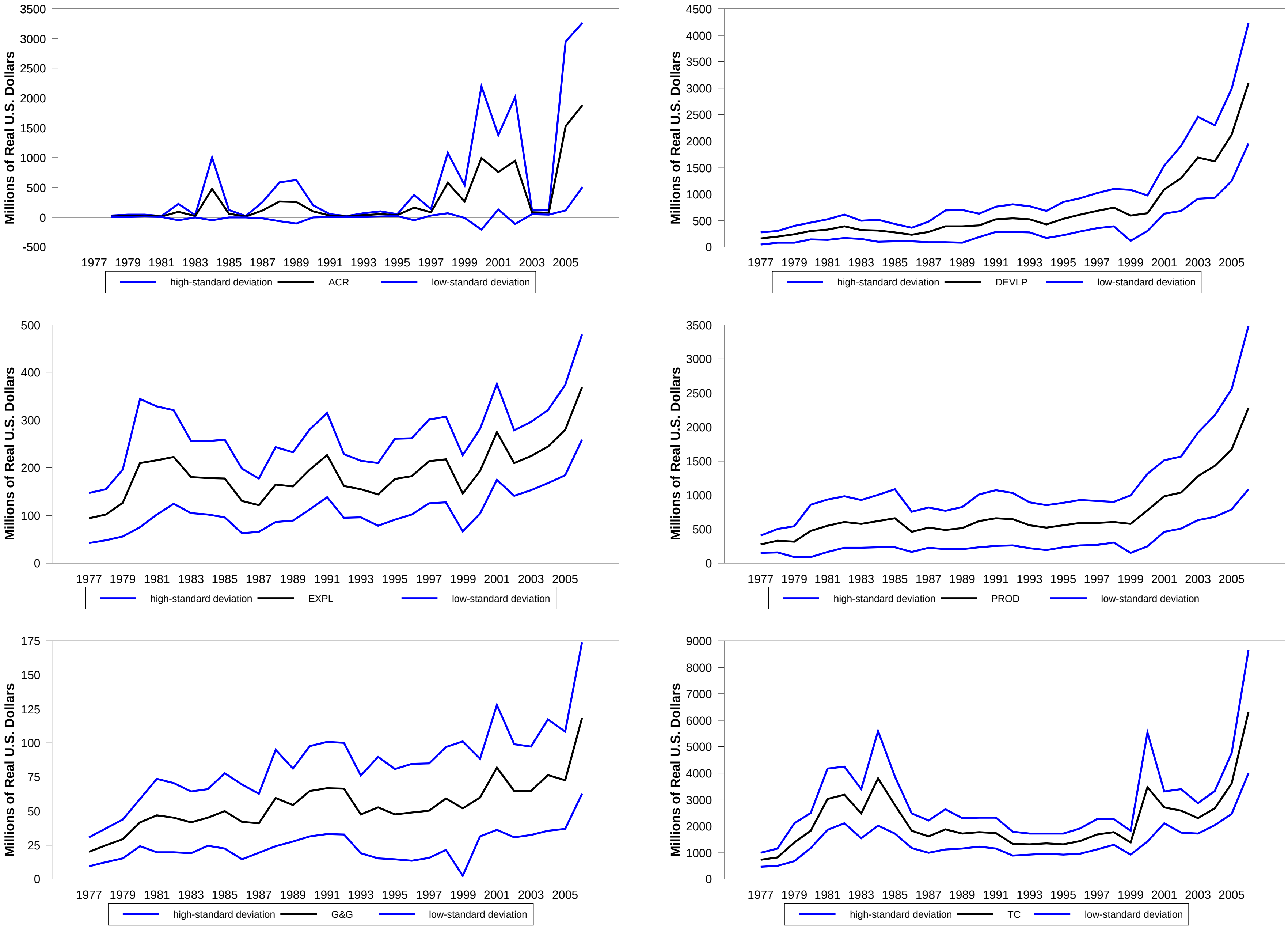
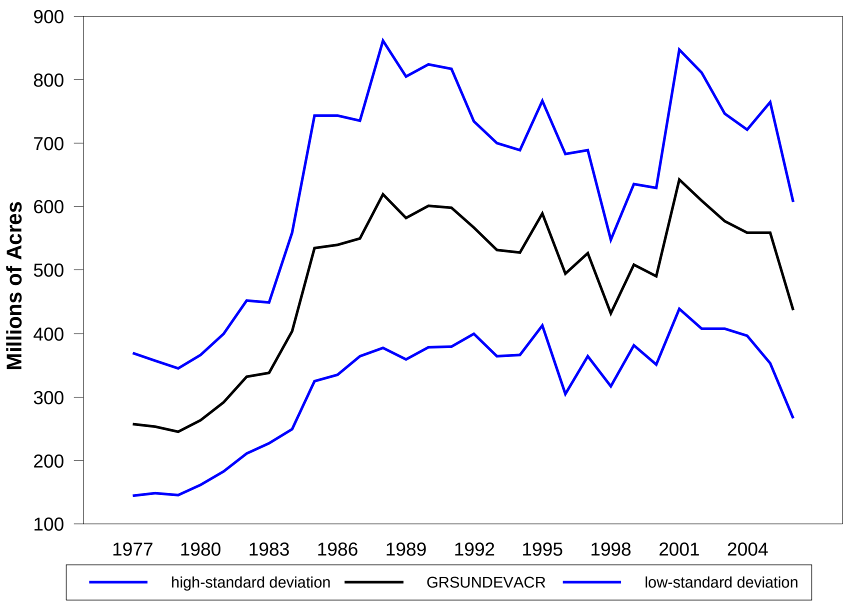
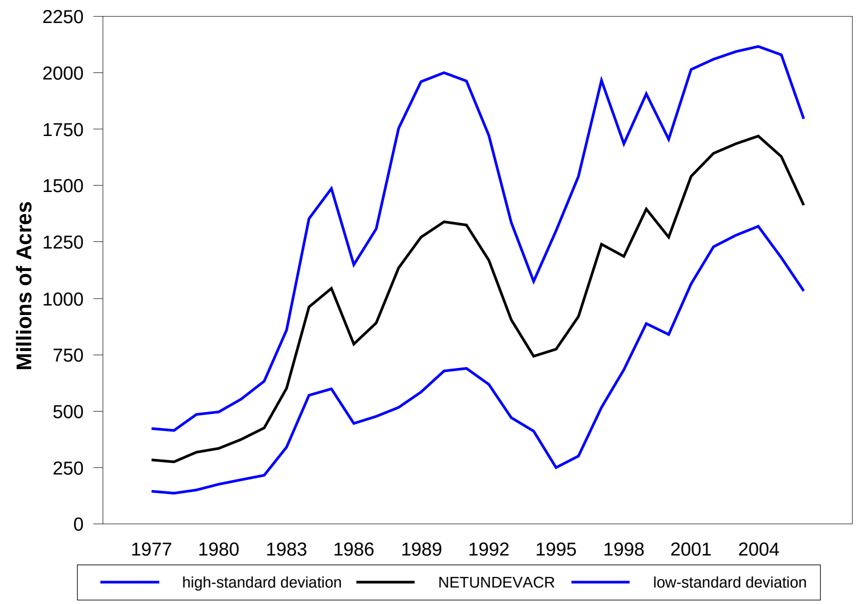


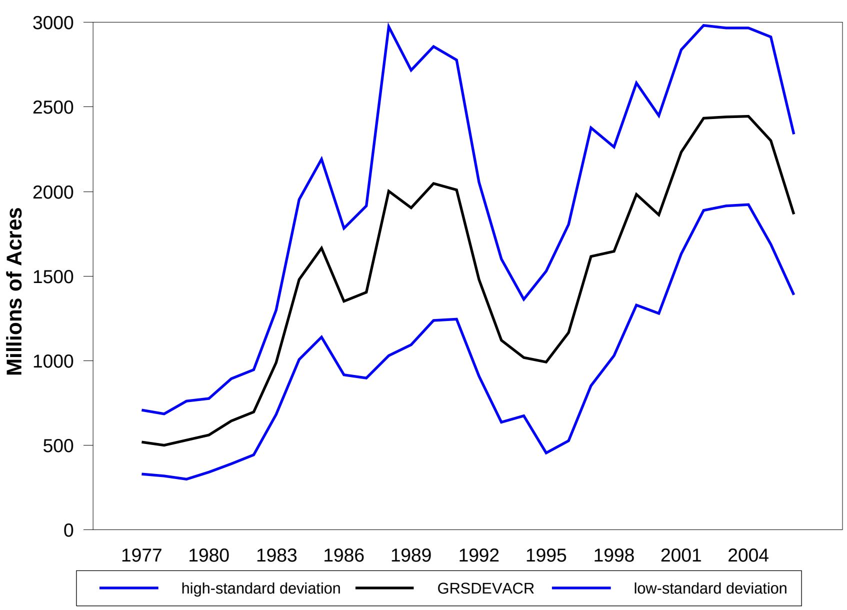
Figure A.2: Foreign Expenditures

Figure A.3: Domestic Expenditures









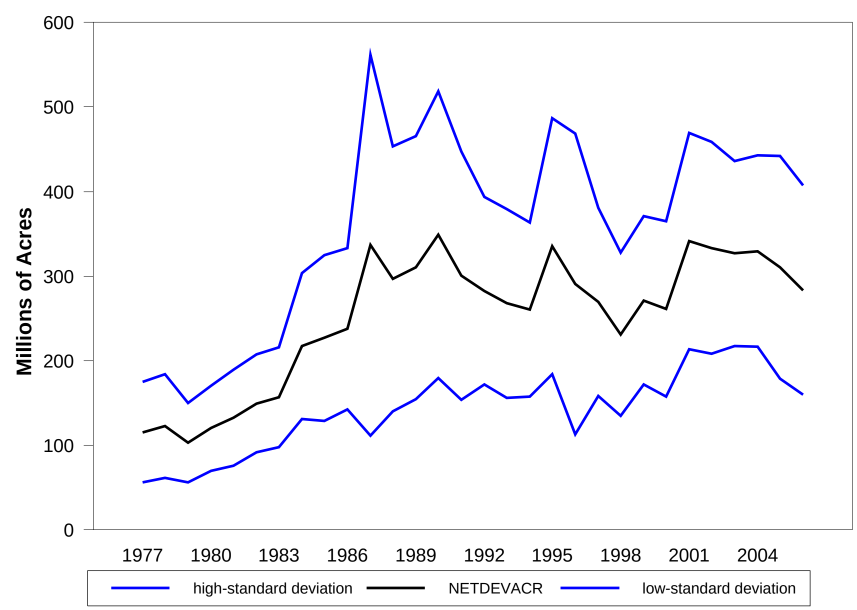


Figure A.4: Gross and Net, Developed and Undeveloped Offshore Acreage Acquisition

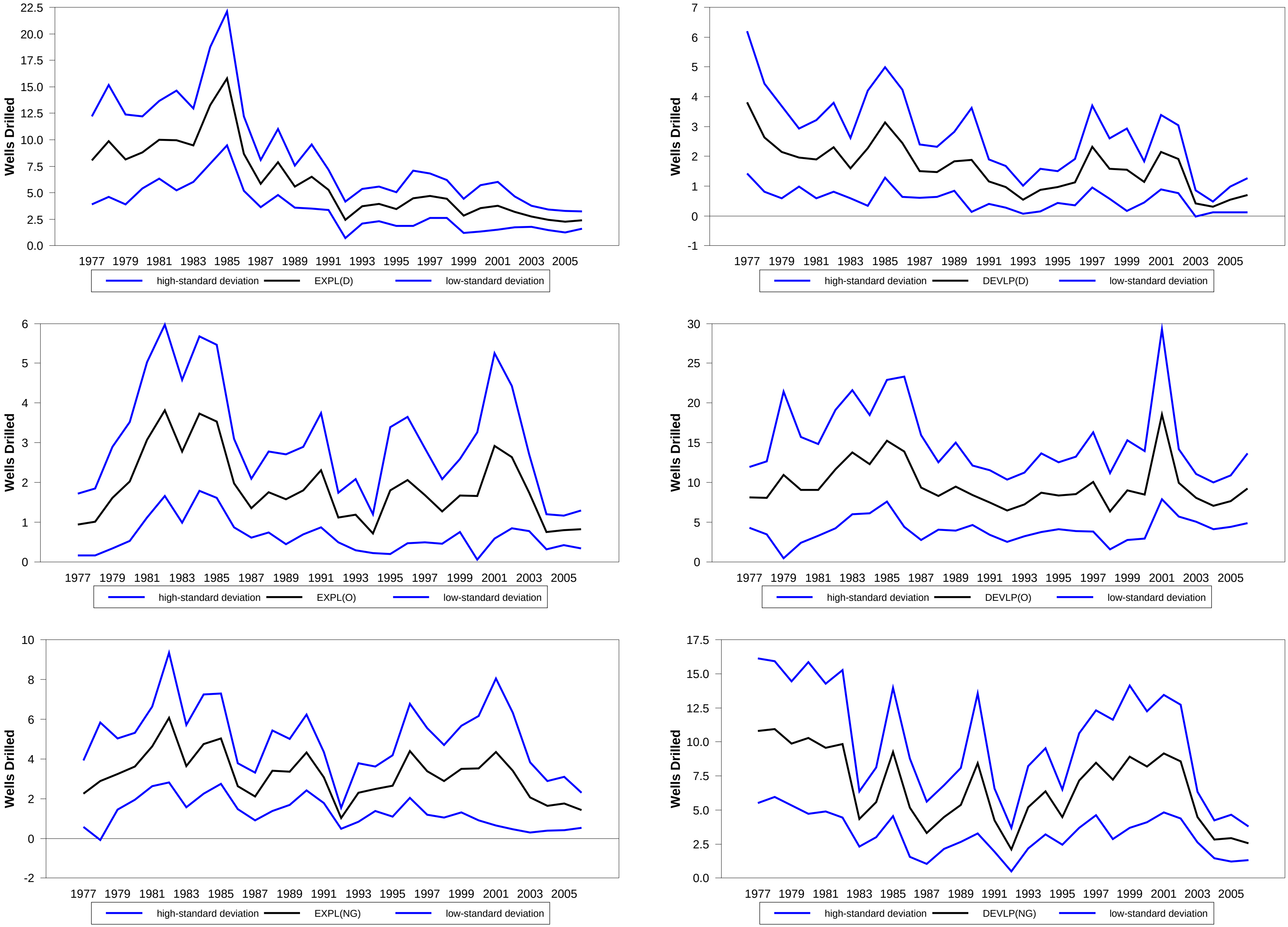


Figure A.5: Offshore Exploration and Development Oil and Gas Wells

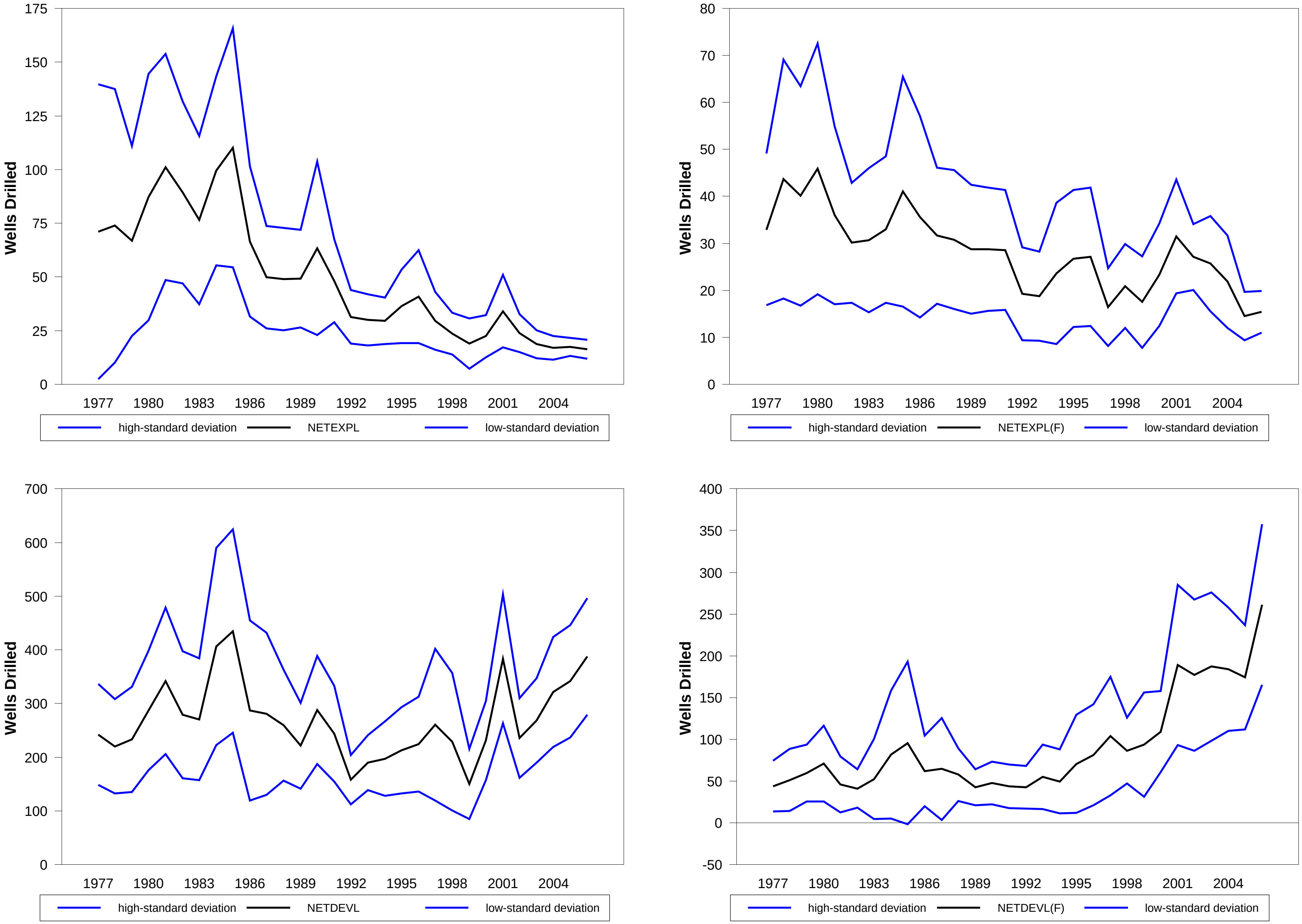


Figure A.6: U.S. and Foreign Exploratory and Development Annual Wells

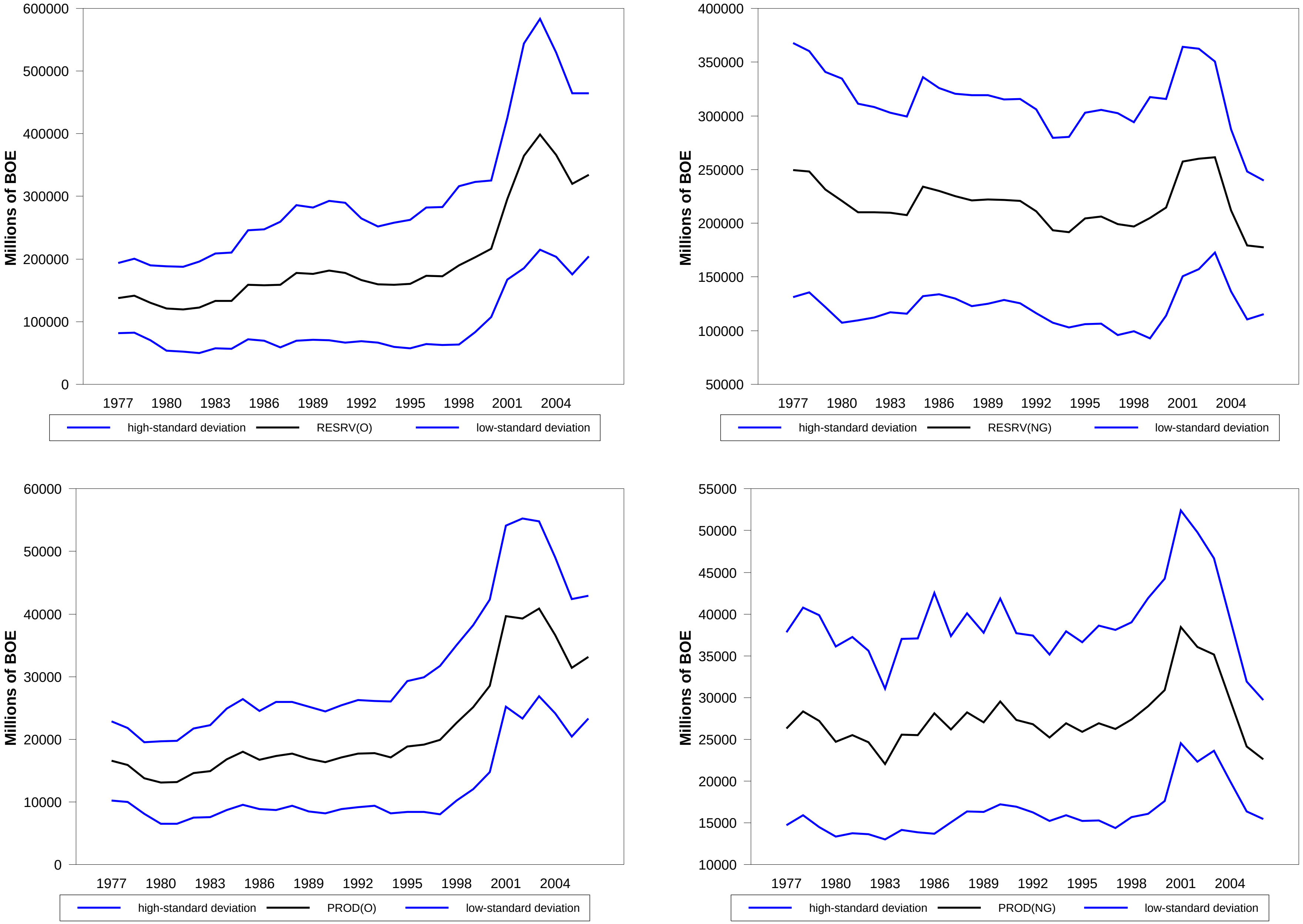


Figure A.7: Offshore Production and Reserves

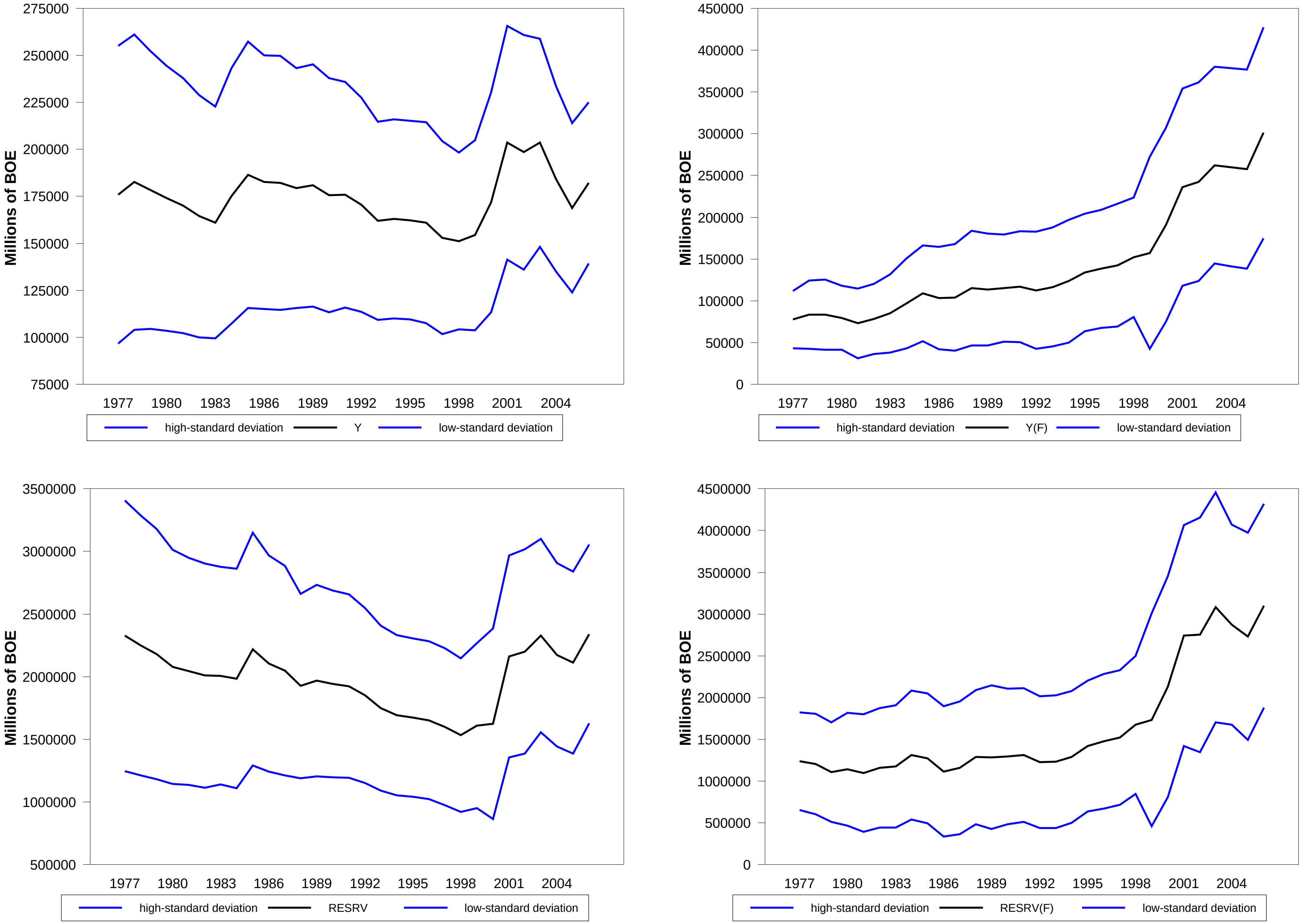


Figure A.8: U.S. and Foreign Production and Reserves

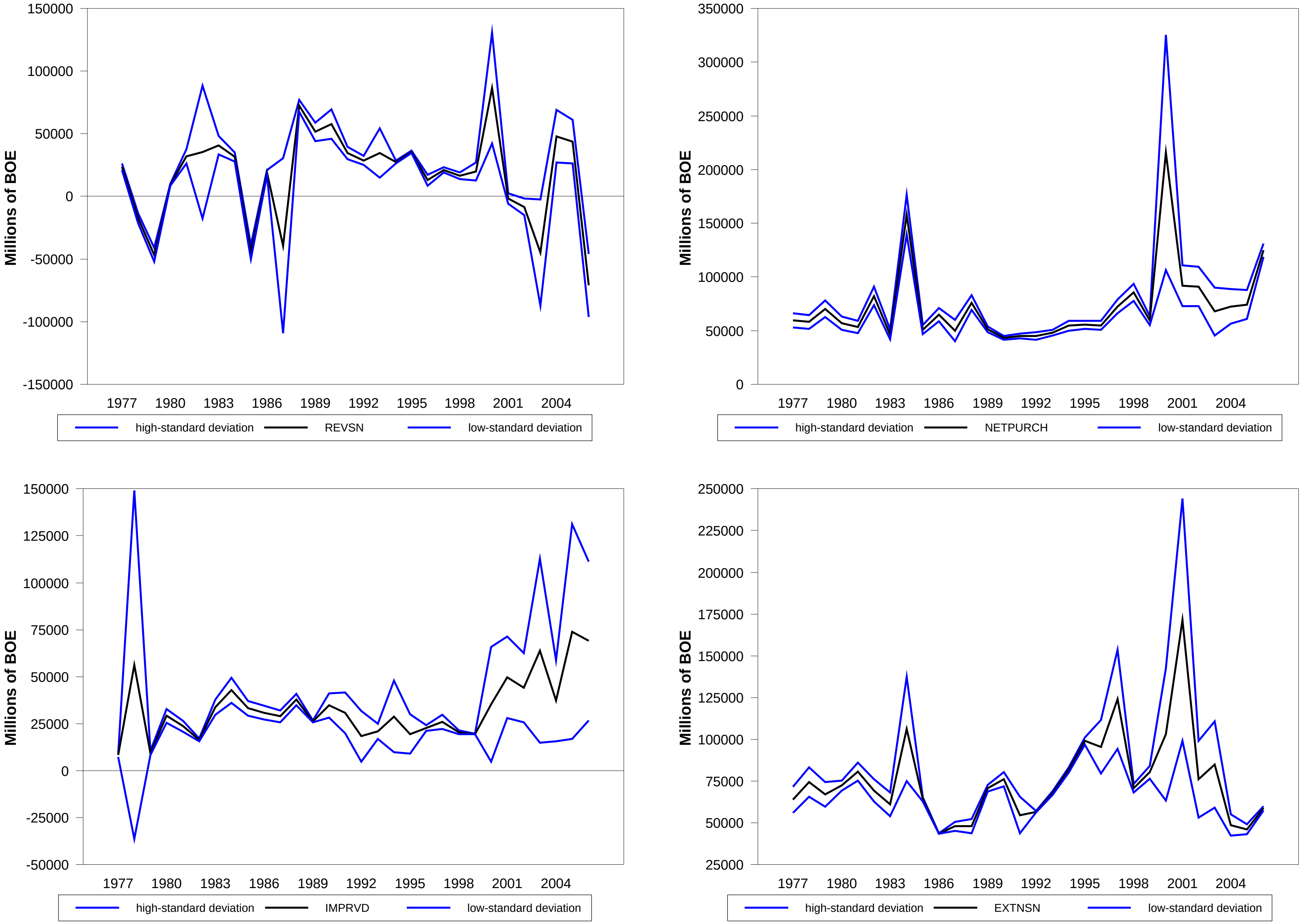
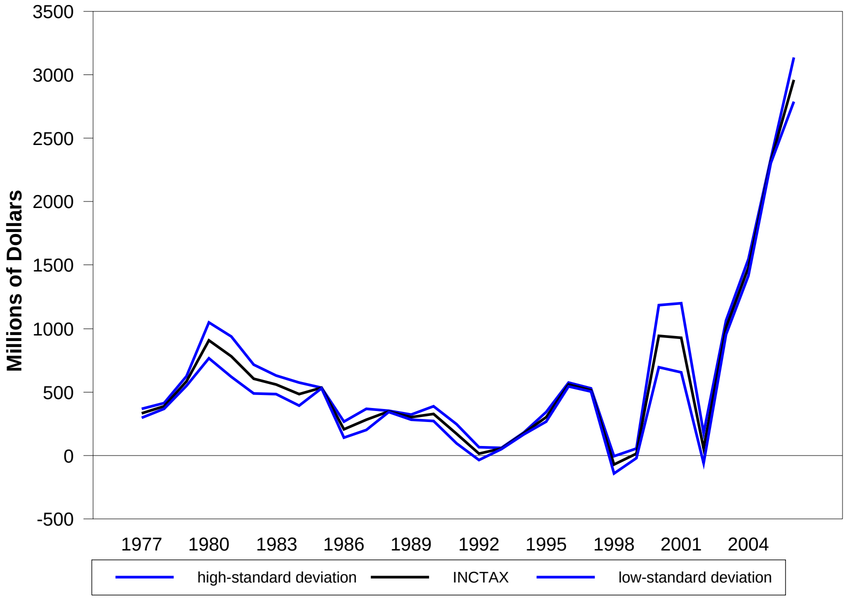
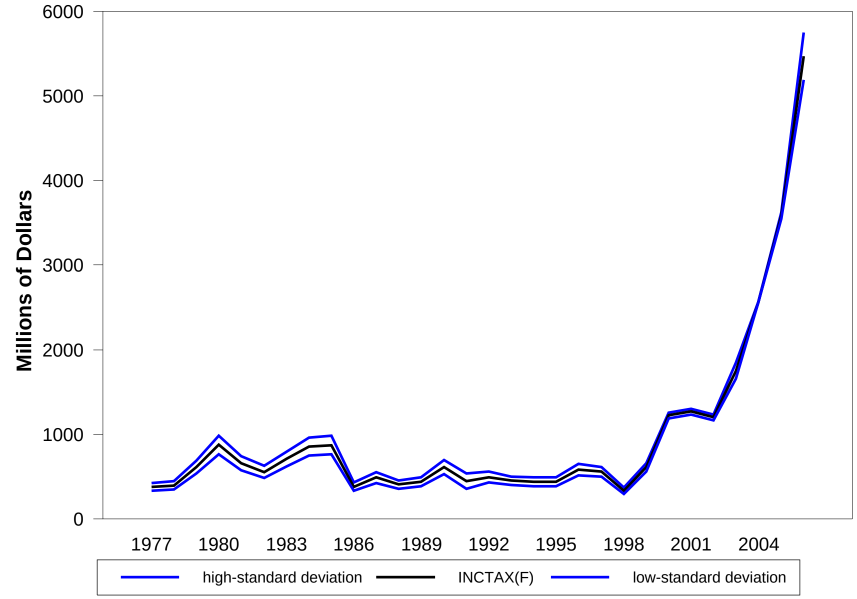


Figure A.9: Breakdown of U.S. Reserves

Figure A.10: Breakdown of Foreign Reserves





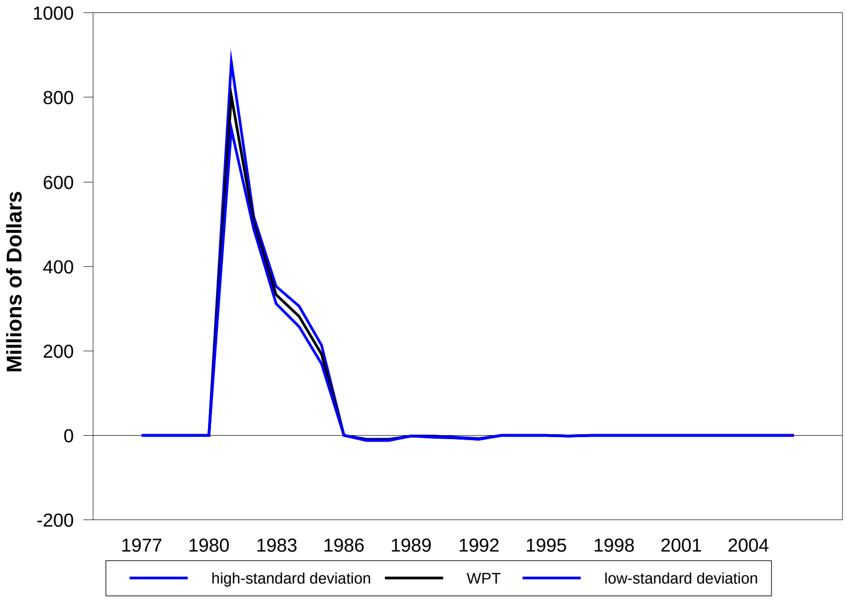


Figure A.11: U.S. and Foreign Taxes

Appendix B

Empirical Test for Market Power

Diewert (1982) provides a nice exposition of the theoretical arguments behind this method. Diewert begins by assuming the production function meets the following conditions:

Assumption 1 *F is a continuous function defined over non-negative real N space,*

Assumption 2 *F is an increasing function,*

Assumption 3 *F is quasi-concave,*

where F is a production function. Diewert also assumes that all levels of inputs are strictly positive and an interior solution exists to the following period t (suppressed) monopolist maximization problem,

$$\max_{\mathbf{x_i}} \{w(D(\mathbf{x_i}))\mathbf{x_i} - C(\mathbf{x_i}, \mathbf{p_i}) : \mathbf{x_i} > 0\} = w(D(\mathbf{x_i}))\mathbf{x_i} - \mathbf{p_i}\mathbf{x_i}, \quad \forall t, \tag{B.1}$$

where $\mathbf{x}$ denotes the vector of inputs, $\mathbf{p}$ the vector of input prices, and wD is inverse demand function. Then both F and its cost function dual, C, share the same technology and hence have equivalent empirical specifications. Assuming that the inverse demand function is differentiable at $\mathbf{x_i}$ and the differential of the cost function also exists then the following first order condition exists,

$$p_{yi} = -wD'(\mathbf{x_i})\mathbf{x_i} + \frac{\partial C(\mathbf{x_i}, \mathbf{p_i})}{\partial \mathbf{x_i}}, \quad \forall t. \tag{B.2}$$

The output price, p_{yi}, is set equal to $w(D(\mathbf{x_i}))$. Assuming the cost function is differentiable with respect to input prices at $\mathbf{x_i}$ and $\mathbf{p_i}$, then Sheppard's lemma gives the following demand equations:

$$\mathbf{x_i} = \nabla_p C(\mathbf{x_i}, \mathbf{p_i}), \quad \forall i, \text{ and } \forall t. \tag{B.3}$$

Finally, assuming that this inverse demand function, $D(\mathbf{x_i}) \equiv \alpha - \delta \ln \mathbf{x_i}$, supplies a suitable local approximation for demand then equation B.2 can be rewritten as

$$p_{yi} = w\delta + \frac{\partial C(\mathbf{x_i}, \mathbf{p_i})}{\partial \mathbf{x_i}}, \quad \forall t. \tag{B.4}$$

The simultaneous estimation of equations (B.3) and (B.4) provide a method to determine whether a firm is producing at marginal cost, i.e., $\delta = 0$.

Appendix C

Ferry's Empirical Method

To generate these estimates Ferry constructs a system of equations. These equations result from the reserve replacement component identity as well as two additional equations for production and number of wells drilled. He disaggregates reserve replacement into oil field discoveries, new reservoirs in an old field, extensions, and revisions. The six equations represent the following six relationships—where each dependent variable is a function of the bracketed independent variables:

$$\text{oil field discoveries}(\text{exploratory wells}, \text{lagged oil field discoveries}, \frac{1}{\text{cumulative exploratory wells}}), \tag{C.1}$$

$$\text{new reservoirs in an old field}(\text{cumulative exploratory wells}, \text{exploratory wells}), \tag{C.2}$$

$$\text{extension}(\text{cumulative exploratory wells}, \text{oil field discoveries}, \text{new reservoirs in an old field}), \tag{C.3}$$

$$\text{revisions}(\text{expected reserves - fall in reserves}, \text{enhanced recovery revisions}, \text{unit price of oil}), \tag{C.4}$$

$$\text{production}(\text{yearly base of production}),\ \text{and} \tag{C.5}$$

$$\text{wells}(\text{unit price of oil}, \frac{\text{barrel of reserve additions}}{\text{exploratory wells drilled}}, \text{index of drilling costs}). \tag{C.6}$$

The yearly base of production is defined as a constant fraction of a three year weighted average of reserves.

The unit price formula attempts to capture all of the policy influences, i.e., price controls and the windfall profit tax, as well as expensing, intangible drilling costs, and depletion allowances that affected oil discovery from 1947-1986. Ferry uses a net present value format and the exhaustibility of oil to derive his unit price formula. That is, he models well productivity by assuming an exponential decline in capacity. To this end, Ferry examines how different government policies affect domestic discovery and production as a whole.

To be specific, Ferry computes the following formula,

$$NPV = (1 - T + bT)\int_{t_0}^{t^*} R(q(t), t)e^{-rt}dt - (1 - T)\int_{t_0}^{t^*} C(q(t), t)e^{-rt}dt, \tag{C.7}$$

where T is taxes, b is the rate of depletion allowance, t_0 represents the initial date of production, t^* represents the concluding date of production, r is the rate of discount, and R and C represent revenue and cost. Then revenue and cost are both functions of the quantity, q, of the resource produced as well as time, t.

Appendix D

Unit Root Tests

The determination of the existence of a unit root in the data can be a difficult task. Tests that I have undertaken include: Perron's (1997) test for an endogenous break in the time series, Elliot et al. (1996) and Ng and Perron's (2001) unit root tests.

Because a break or shift in trend can be misinterpreted as a unit root, I implement Perron's unit root test to investigate this possibility. Perron's unit root test allows for an endogenous change in the slope or level of the series.

I employ the Elliot et al. DFGLS test for a unit root, which is similar to the augmented Dickey-Fuller t-test. The authors suggest that their test improves the power of the unit root test over the standard Dickey-Fuller test, when there is an unknown deterministic mean or trend present. Elliot et al. avoid having to estimate the deterministic trend nuisance parameters by using a set of test procedures that are invariant to them. The authors suggest regressing $y_{\bar{\alpha}}$ on $Z_{\bar{\alpha}}$ where $y_{\bar{\alpha}} \equiv (y_1, y_2 - \bar{\alpha} y_1, \ldots, y_t - \bar{\alpha} y_{t-1})$ and $Z_{\bar{\alpha}} \equiv (z_1, z_2 - \bar{\alpha} z_1, \ldots, z_t - \bar{\alpha} z_{t-1})$. y_t is the variable of interest, z_t is defined as the vector $[1, t]'$, $\bar{\alpha} \equiv 1 + \bar{c}/T$, and

$$\bar{c} = \begin{cases} -7 & \text{if} \quad \text{drift} \\ -13.5 & \text{if} \quad \text{linear trend} \end{cases} . \tag{D.1}$$

The regression coefficient can be used to construct a new detrended series that does not contain a deterministic component; it is now possible to proceed with the normal Dickey-Fuller procedure. If $\widetilde{\xi}$ is our estimated coefficient from the regression of $y_{\bar{\alpha}}$ on $Z_{\bar{\alpha}}$, we can construct a new series by the following calculation: $\widetilde{y}_t \equiv y_t - \widetilde{\xi}' z_t$. Differencing this series and performing the following regression

$$\Delta\tilde{y}_t = \eta_0\tilde{y}_{t-1} + \eta_1\Delta\tilde{y}_{t-1} + \ldots + \eta_p\Delta\tilde{y}_{t-p} + \epsilon. \tag{D.2}$$

The new null hypothesis tests if $\eta_0 = 0$.

Extending this analysis, Ng and Perron construct four additional statistics using the detrended data generated above, two of which can be seen below.

$$MZ_\alpha = \left(T^{-1}\tilde{y}_T^2 - f_0\right)/2k, \tag{D.3}$$

and

$$MSB = \left(k/f_0\right)^{1/2}, \tag{D.4}$$

where f_0 is the zero frequency estimate of the residual spectral density and $k = \sum_{t=1}^{T-1}(\tilde{y}_t/T)^2$. The authors suggest these additional two statistics constitute a battery of tests with good power. These tests generally outperform other unit root tests in the published literature and in particular when facing an autoregressive parameter close to unity which causes many tests, including the augmented Dickey-Fuller test, to have low power.