# Taxes and the Extraction of Exhaustible Resources: Evidence from California Oil Production*

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January 2013

**Abstract**

Rapid oil price increases frequently bring calls for special oil industry taxes. This paper uses new well-level production data and price variation induced by federal oil taxes and price controls to estimate how taxes affect production. Theory suggests temporary taxes create strong incentives for retiming productioneven well shutting. Empirical estimates suggest little shut-in in response to taxes, but substantial production retiming with an estimated elasticity between 0.208 and 0.261. The estimates are used to calibrate a simple model of the efficiency cost of tax-induced distortions, implying that a 15% tax reduces social efficiency by between 3% and 25% of the revenue raised.

**Keywords:** Taxes, Energy, Oil, Supply Elasticity.
**JEL Classification:** H23, H25, Q41, Q48.

*I thank Michael Greenstone, Jon Gruber, and especially Jim Poterba for valuable advice and encouragement. I also thank Maria Damon, Mike Golosov, Cynthia Kinnan, Matt Notowidigdo, John Parsons, Bob Pindyck, Mar Reguant-Rido, Steve Salant, Wolfram Schlenker, and seminar participants at MIT, NYU, Resources for the Future, University of Illinois, London School of Economics, Columbia University, University of Colorado Boulder, the Ford School of Public Policy, and the 2010 NTA annual meeting for helpful comments.

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# 1 Introduction

Steep increases in oil prices often bring with them renewed calls to levy additional taxes on the oil industry. Most recently, the rapid run-up in prices during 2008 led to legislative proposals and campaign trail discussions of new "windfall profit" taxes. Advocates of such taxes argue that the upfront drilling investments necessary for current production were made during periods of much lower prices and that profits from such investments are an unearned "windfall." Critics counter that additional taxes may have deleterious effects on domestic oil production, leading to increased U.S. dependence on foreign oil. The consequences of these types of taxes hinge critically on how producers respond to changes in after-tax price.

Despite the importance of estimates of the elasticity of U.S. supply for assessing the impact of policy changes—like the levying of new excise taxes or the elimination of current depletion subsidies—consensus elasticity estimates have been lacking. Previous studies have relied exclusively on time-series variation and have mostly found very small and economically insignificant elasticities.[1] Most policy studies of oil markets rely on a range of plausible elasticities due to the lack of consistent credible estimates. In fact, the 2006 Congressional Research Service (CRS) report on proposed windfall profit taxes stated, "few studies generate reliable estimates and in fact some studies estimate negative supply elasticities, which are not plausible."[2] Thus the CRS report, like

[1] Hogan (1989) and Ramcharran (2002) found significant supply elasticities of 0.09 (0.03) and 0.05 (0.02), respectively. Jones (1990) and Dahl and Yücel (1991) found insignificant elasticities of 0.07 (0.04) and -0.08 (0.06), and Griffin (1985) found a significant negative elasticity, -0.05 (0.02). Hogan (1989) also estimated a longer-run elasticity of 0.58 (0.18).

[2] Lazzari (2006)

previous studies by the Congressional Budget Office (2012) and the Organisation for Economic Co-operation and Development (OECD) (2004), employed a number of assumed elasticities—CRS used supply elasticities of 0.2, 0.5 and 0.8—rather than settling on a specific elasticity estimate.[3]

I estimate the supply response using a new rich dataset that reports monthly production for all onshore wells in the state of California—the third-ranking state in oil production—over a 31-year period beginning in 1977. I construct a dataset of 30,025,957 observations describing 140,672 wells. The sample includes wells that were already completed and wells completed during the period. In addition to monthly production, the data report monthly values, for each well, for the quality of oil produced, the firm operating the well, the method of pumping, exact location, the field and pool it taps, and whether it is capable of producing or is shut-in. This level of detail allows me to assign each well its appropriate regulatory and tax regime treatment, following the *Code of Federal Regulations* for each year. Using this policy detail and monthly field-by-grade prices from Platt's *Oil Price Handbook and Oilmanac* for each year, I am able to trace over time the path of after-tax prices for each well, taking into account differential regulatory and tax treatment across wells.

Because these federal policies created substantial variation in after-tax price over time, I am able to identify the supply response using only within-well variation. In fact, regulatory and tax policy generate enough across-well vari-

[3]The OECD, in its 2004 Economic Outlook, based its projection of production by countries that are not members of the Organization of the Petroleum Exporting Countries on elasticities of 0.1, 0.3, and 0.5. The U.S. Department of Energy's Energy Information Agency does not explicitly state the elasticities it uses in its analyses, but its forecasts indicate that it used an elasticity of 0.2 over a ten-year window and virtually zero for one-year responses.

ation in after-tax price in each month-year that I can also non-parametrically control for common unobserved time factors affecting well productivity.

Previous attempts to estimate the supply elasticity of oil production suffer from several difficulties that my well-specific monthly data can rectify. The use of the readily available but non-representative Department of Energy Monthly Energy Review (MER) average pre-tax first purchase price series introduces measurement error in the price variable, leading to potential downward biases in estimates of the supply response. When I estimate my oil production models with the MER price series rather than the more accurate field-by-grade prices adjusted for well-specific regulatory and tax treatment, I find elasticity estimates an order of magnitude smaller than my baseline estimates. These findings are similar to estimates found in the previous literature.

To assess the welfare cost of taxes on oil extraction, it is important to distinguish between responses along the extensive and intensive margins. If the reduction in production is driven by the shutting-in of wells, the high cost of reversing shut-in makes this a potentially permanent loss of oil. On the other hand, if production is reduced primarily along the intensive margin, operators are simply tilting their extraction paths forward in response to the tax: they will pump less today and more in the future. This intensive adjustment will still reduce producer surplus, but the welfare cost will come from the delay in revenues and the additional cost of sub-optimally pumping the well, not from an output gap. As my analysis examines the within-well supply response, the exploration margin is not a part of my assessment of the deadweight loss of temporary taxes.[4] Temporary taxes are more likely to delay rather than curtail exploration activities, meaning that temporary taxes could lead to even more production re-timing than is captured here.

My estimates suggest that production from existing wells is price-responsive. The main results show an after-tax price elasticity of oil production in California of 0.237, with a 95 percent confidence interval of 0.180 to 0.295. Response along the extensive margin is minimal; a ten percent decrease in after-tax price would lead to at most a 1.17 percent increase in the shut-in rate. The estimates are used to calibrate a simple model of the efficiency cost of tax-induced distortions relative to the no-tax optimal extraction path. These calculations suggest that a 15 percent temporary excise tax on California oil producers reduces the present value of producer surplus by between three and 25 percent of the government revenue raised, depending on the original life of the well and the duration of the temporary tax.

## 2 Modeling the Impact of Temporary Taxes

The model highlights how temporary taxes—which have been recently proposed in reaction to rapidly increasing oil prices—create strong incentives for retiming production and how the deadweight loss from such a tax can be assessed.

[4] As new wells are completed they are added to the sample used to generate the empirical estimates, but since the analysis uses only within-well variation in after-tax price, the estimate does not measure the impact of new wells on aggregate production.

## 2.1 The Extraction Problem

As in the Hotelling (1931) model, the well operator chooses an extraction path to maximize the present value of total profit over the life of the well, taking into account the exhaustibility of the reserves of his well.[5] Operators are assumed to be price-takers with known reserves.

Exhaustibility in effect makes extraction a "pump today or pump tomorrow" decision for the operator. This opportunity cost creates an incentive for holding the resource *in situ*, tempering the incentive to extract and sell.

Because the typical U.S. well lacks sufficient natural subsurface reservoir pressure for the oil to flow to the surface, most wells are pumped, making extraction costly. Extraction costs include fixed costs, such as the user-cost of pumping equipment, and operating costs, such as energy inputs to drive the pump and labor costs of monitoring. The cost function is modeled as convex in the extraction rate with an additional fixed cost of operating. Letting $q_t$ denote the extraction rate and $f$ the fixed cost of operation, the cost function can be written

$$c\left(q_t\right) = \begin{cases} cq_t^2 + f & \text{if the well produces} \\ 0 & \text{if the well does not produce} \end{cases}$$

where $c$ is a parameter of the cost function.

For simplicity, it is assumed that the full price path and total reserves, $R_0$,

[5]Hotelling's seminal work has been extended and discussed by numerous authors, including Dasgupta and Heal (1980).

are known at time 0. The problem can be written as a Hamiltonian

$$\Lambda\left(q_t, \lambda_t\right) = \int_0^{T(\mathbf{p})} e^{-rt}\left[p_t q_t - c\left(q_t\right)\right] dt - \lambda_t\left[\int_0^{T(\mathbf{p})} q_t dt - R_0\right] \tag{1}$$

where $p_t$ is the price at time $t$, and $T\left(\mathbf{p}\right)$ is the time at which all profitable oil has been extracted and the economic limit of the well has been reached.[6] The shadow value of reserves is $\lambda_t$. The life of the well, $T\left(\mathbf{p}\right)$, is a function of the price path—higher average prices will accelerate extraction and shorten well life. The reserves will be fully exhausted at time $T$.[7] The exact shape of the extraction path is determined by the marginal cost of extraction and the discount factor.

Given the quadratic cost function, the optimal extraction at time $t$ is

$$q_t^* = \frac{p_t}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left(p_T - 2\sqrt{fc}\right)}{2c} \tag{2}$$

where again $T$ is the economic life of the well.[8] The extraction rate declines over time due to the discounting of future profits. Wells that are further from their economic limit, $T$, will pump at a faster rate. The extraction rate is

[6] In the last period of extraction the operator will choose an extraction quantity that equates the marginal and average cost of extraction, for the specific cost function employed below that is $q_T = \sqrt{\frac{f}{c}}$. After extracting $q_T$ the operator shuts the well and the extraction rate falls to zero.

[7] Since $q_T$, the production quantity that equates marginal cost and average cost, is, by virtue of minimizing average cost, less than the production quantity that equates marginal cost and price—the operator finds all remaining production profitable.

[8] More specifically, $T\left(\mathbf{p}\right)$ is implicitly defined by the exhaustibility constraint

$$\int_0^T \left[\frac{p_t}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left(p_T - 2\sqrt{fc}\right)}{2c}\right] dt = R_0$$

inversely proportional to the slope of the marginal cost function—wells with more steeply convex costs of extraction will extract more slowly.

## 2.2 Excise Taxes and the Extraction Path

*A Permanent Excise Tax*

After the introduction of a permanent excise at rate $\tau$, the operator's optimal extraction rate falls to:

$$q_t^* = \frac{p_t\,(1-\tau)}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left((1-\tau)\,p_T - 2\sqrt{fc}\right)}{2c} \tag{3}$$

The permanent excise tax reduces extraction in all periods. Because the tax reduces revenues in all periods, including the final period, the well may shut down with reserves remaining in the well if the marginal cost of production exceeds the after-tax price. In this sense, permanent taxes can induce shut-in.

*A Temporary Excise Tax*

The introduction of an unanticipated temporary excise tax that is known to be in place until time $t_1$ reduces after-tax price in the near term, but leaves the after-tax price after $t_1$ unchanged. For simplicity assume price is constant.[9] The price between time 0 and $t_1$ is denoted by $p_1 = (1-\tau)\,p^W$, where $p^W$ is the pre-tax world price, and the price after $t_1$ is denoted by $p_2 = p^W$.

For wells with pre-tax economic lives that extend beyond time $t_1$, while

[9] Adding uncertainty to the model would affect the shape of the original extraction path, depending of the exact form of the stochastic process. It would not change the implication of interest–a temporary tax creates strong incentives to shift production to the post-tax period regardless of the shape of the original extraction path.

the tax is in place between 0 and $t_1$ the operator's optimal extraction rate is:

$$q_t^* = \frac{p_1}{2c} - \frac{e^{-r(T(p_1,p_2)-t)}\left(p_2 - 2\sqrt{fc}\right)}{2c} \tag{4}$$

Assuming zero fixed costs for expositional clarity, the total impact of a change in $p_1$ on the extraction rate while the tax is in place is:

$$\frac{dq_t^*}{dp_1} \geq \frac{1}{2c} - \frac{e^{-r(T(p_1,p_2)-t)}}{1 + e^{-r(T(p_1,p_2)-t)}} \frac{rt_1}{2c} \tag{5}$$

again, where $p_1 = (1-\tau)\, p^W$—higher tax rates lead to lower extraction rates. The first term of equation (5) describes the direct impact of a tax change on extraction: a higher after-tax price accelerates extraction. The second term captures the mitigating impact of the exhaustibility constraint: higher price before $t_1$ reduces the life of the well, increasing the opportunity cost of extraction since the last barrel is pumped sooner.

For long-lived wells, where $T(p_1, p_2)$ is large, the impact of the second term of equation (5) is small, especially if the tax is in place for a relatively short period of time. If $T(p_1, p_2)$ is large, then equation (5) is approximately:

$$\frac{dq_t^*}{dp_1} \geq \frac{1}{2c} \tag{6}$$

In other words, the impact of a 10 percent decrease in the after-tax price, $p_1$, is a $(0.05/c)$ reduction in the extraction rate for wells that are not near the end of their economic life. The empirical work aims to estimate the cost function parameter $c$.

Finally, wells with high fixed or operating costs and little remaining reserves may shut-in in response to even a temporary tax. If the well operator planned to shut his well before time $t_1$ prior to the introduction of the tax, the introduction of the tax will hasten his abandonment since, for his purposes, the temporary tax effectively is a permanent tax.

In summary, excise taxes affect both the current price and the opportunity cost of extraction. Temporary excise taxes lead the operator to re-time production, shifting extraction from the tax period to the future when the tax has expired. The temporary tax's deadweight loss does not arise from a reduction in total quantity; it comes from the additional costs of sub-optimally pumping the reserves and the real dollar cost of delaying production.

The implications of a temporary tax based on the simple model described above suggest a strategy to assess the impact and welfare cost of such taxes. Empirically estimating the cost parameter $c$ would allow for assessments of the welfare cost of excise taxes on the extraction of exhaustible resources, taking the dynamics of extraction into account.

# 3 Institutional Background

The estimation strategy makes use of price changes driven by price regulation, decontrol, and the imposition of federal excise taxes. These policies significantly altered producer prices and created considerable differences in producer price across wells. This section provides background information on the California oil industry and details the relevant history of government actions affecting producer prices.

## 3.1 Oil Facts and Producer Price

California is the third highest oil producing state in the third highest producing nation. Onshore oil producers in California account for roughly one percent of total world production.[10] The oil produced in California is of lower quality than more prominent benchmark crudes such as West Texas Intermediate (WTI). American Petroleum Institute (API) gravity measures the specific gravity, or "heaviness" of oil, which determines how efficiently the crude can be refined into petroleum products.[11] California oil was more than 60 percent heavy or very heavy crude during the 1977-1985 period. Heavy oil is generally more expensive to extract and refine.[12] Given the result from Section 2 that wells with higher marginal costs will be less responsive to changes in after-tax price, it is reasonable to think that estimates based on California wells provide a lower bound on tax-price responsiveness for the average U.S. well.

U.S. producer prices are not sensitive to the production decisions of individual U.S. operators. Since they account for a small share of world production and operate in a market alongside a cartel, U.S. oil producers, including California producers, can reasonably be assumed to be price-takers.[13] Refiners

[10]U.S. Department of Energy, Energy Information Administration:
http://tonto.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm

[11]API gravity is an inverse function of specific gravity:
$\text{API Gravity} = \frac{141.5}{\text{Specific Gravity}} - 131.5$

[12]Heavy oil has an API gravity less than 20; very heavy oil has an API gravity less than 16. Higher API gravity oil is lighter and sells for a premium. During the 1977-1985 period, 11.6 percent of California crude was heavy while 49.8 percent was very heavy.

[13]Kilian (2009) asserts "the price of crude oil is determined in global markets." Domestic pre-tax prices were assumed to track world prices in other empirical studies such as Smith

always had the option to purchase imported oil—which was exempt from both price controls and the WPT. While the WPT was in place, the availability of tax-exempt imports fixed the refiner price at the world price; producer prices were reduced by the full amount of the tax.[14]

## 3.2 Decontrol and the 1980 Windfall Profit Tax

The decontrol of oil prices began in 1976 with marginally productive wells called stripper wells. Rising prices and less stable foreign sources prompted concerns regarding U.S. oil independence and generated interest in increasing domestic oil production. The Carter administration began decontrolling non-stripper domestic crude in June 1979. Decontrol went forward with the understanding that the sudden increase in domestic producer prices would be taxed at the federal level.[15] The 1980 Windfall Profit Tax was signed into law April 2, 1980, and virtually all non-Alaskan oil owned by a taxable private party was subject to the tax. Purchasers withheld the tax from the amounts otherwise payable to a producer and filed quarterly WPT tax returns with the Internal Revenue Service.

The timing of decontrol varied by API gravity, and by the age and productivity of the well from which oil was extracted. These same oil and well

et al. (1986).

[14]Though transportation costs are small, roughly 5 percent of oil prices, domestic producers may have been able to pass a fraction of the tax, equal to the transport cost, on to purchasers. All oil produced in California is refined within the state, but refiner demand exceeds production so imports comprise the difference. Imports come largely from Canada and Mexico and average transport costs run roughly $1.30 per barrel according to Rodrigue (2009).

[15]According the Joint Committee on Taxation's General Explanation of the Crude Oil Windfall Profit Tax of 1980, "without such a tax, decontrol probably could not [have gone] forward."

characteristics determined the WPT treatment as well. The WPT taxed oil that was typically more costly to extract at a lower tax rate. Tax-favored oil included heavy oil that had an API gravity of 16 or less, and oil from stripper wells, which produce, on average, less than 10 barrels of oil per day for at least 12 months.

All taxable oil was divided into three tiers under the WPT; each tier corresponded to a different tax rate.[16] An operator's WPT tax liability was equal to the product of the WPT tax rate and the difference between the selling price and a tier-specific base price for each barrel of oil he sold. WPT payments were deductible from corporate taxable income, meaning that the after-tax price ($ATP_{it}$) received by the operator of well $i$ at time $t$ was:

$$\mathrm{ATP}_{it} = \begin{cases} \left(1 - \tau_t^{Corp}\right)\left(P_{it} - \tau_{it}^{W}\left(P_{it} - B_{it}\right)\right) & \text{if } P_{it} > B_{it} \\ \left(1 - \tau_t^{Corp}\right) P_{it} & \text{otherwise} \end{cases}$$

where $B_{it}$ is the real base price. The WPT was legislated as a temporary tax. At its height, the WPT raised \$44 billion in gross revenue (before corporate income tax deductibility), or roughly half the revenue raised by the corporate income tax. Statute required the tax to expire by 1991. In reality the tax became ineffective due to sharp decreases in oil prices in 1986; 1985 was the last year it raised any revenue. In fact, the WPT was repealed in 1988 to eliminate the administrative burden of a tax that did not raise revenue. The timing of decontrol and the simplified details of WPT treatment for each of

[16] Specific categories of oil, largely state-, Native American-, or charitable trust-owned oil, were exempt from the WPT. See Lazzari (2006) for further details.

the three tiers of oil follow.

*Tier I Oil*

Tier I oil was non-heavy oil extracted from a non-stripper well that produced oil in 1978. Tier I oil was subject to price controls through 1979. Price controls on Tier I oil were phased out gradually.[17] At the end of January 1981, the phase-out of price controls was abruptly ended and Tier I oil was fully decontrolled. The base price for Tier I oil was 21 cents less than the May 1979 price control price for the property. The tax rate on Tier I oil was 70 percent.

*Tier II Oil*

Tier II oil consisted of non-heavy oil from stripper wells that produced oil in 1978, and oil produced from a Naval Petroleum Reserve (NPR) field. A well is considered a stripper well if it has ever averaged less than 10 barrels of oil per day for 12 consecutive months after 1972. Oil produced from stripper wells was exempted from price controls in August 1976. An NPR field is one of four fields owned by the federal government to which access is leased to private operators. The base price for Tier II oil was the December 1979 selling price of oil from the same property multiplied by 0.425, a conversion factor that achieved a statutorily set average base price of $15.20. The tax rate on Tier II oil was 60 percent.

*Tier III Oil*

[17] Beginning in January of 1980, the selling price was a weighted average of the world market price and the price control price with the weight on the market price equal to 0.046 multiplied by the number of months since December 1979.

Tier III oil was composed of two types of oil, new oil from wells that did not produce oil in 1978 and heavy oil with an API gravity of 16 or less. New oil was fully decontrolled in June 1979. Price controls on heavy oil were lifted August 17, 1979. The base price for both new and heavy oil was the December 1979 selling price of oil from the same property multiplied by 0.462. Heavy and new oil were the most tax-favored types of oil; the tax rate on Tier III oil was 30 percent initially and was gradually reduced to 22.5 percent beginning in 1982.

The three tiers of oil, and even different categories of oil within Tier III, were treated very differently by government policies. Differences in the timing of decontrol and differential tax treatment provide the variation in after-tax price that generates the supply elasticities estimated here. These policies created cross-sectional variation in after-tax price allowing for flexible controls for underlying common time-varying factors.

# 4 New Production and Price Data

The decontrol of oil prices and the introduction of federal excise taxes created substantial variation in after-tax price over time and across wells. These policies classified wells into different regulatory and tax tiers by the characteristics of the well and the oil it produced. Thus well-level data are necessary to account for and make use of this substantial variation. Wells within a field could be assigned very different after-tax producer prices depending on whether they produce the same kind of oil, share the same stripper status, or produced in

1978. To use this well-level variation, I assembled a new database of well-level production and after-tax producer prices that describes every onshore well in California starting in 1977, which encompasses the regulatory and tax periods. These data have not been used in previous studies.

## 4.1 Data

The data used in this study cover all potentially active onshore oil wells in California, beginning in 1977. The main analysis regarding the impact of price regulation and excise taxes makes use of the more than 75,000 oil wells that were capable of producing at some point during the 1977 to 1985 period. The State of California Department Conservation Division of Oil, Gas and Geothermal Resources requires operators to report monthly production and characteristics for all completed wells that are potentially capable of production. Characteristics reported each month include the date of well completion, API gravity of the oil produced, the field and pool being tapped, operator name, and the status of the well. The data are particularly well suited for the analysis since they provide monthly information that allows more precision in the timing of price changes relative to the annual or quarterly data used in other studies. More importantly, the data report the characteristics necessary to determine the timing of decontrol and WPT tax treatment for each well.

Some adjustments to the data were necessary. In months where oil production is zero either because the well is not yet complete or is shut-in, no API gravity data are reported; I assign these well-month observations the soonest future API gravity in the case of uncompleted wells and the most recent previous API gravity in the case of shut-in wells. Stripper well status is determined by examining production history within the data, so the share of wells qualifying for stripper status would rise mechanically at the end of 1977 if only production history determined stripper status. To address this data concern, I back-fill stripper status so that a well that is determined to be a striper well in January 1978 is classified as a stripper well in 1977 as well.

As explained in Section 3, all oil does not trade at a single price; different grades trade at their own prices. The price data are from Platt's *Oil Price Handbook and Oilmanac*, which provides monthly field-by-field posted prices by API gravity for controlled and decontrolled oil. Fields for which price data are not available are assigned the average price for oil of the same API gravity for wells in California that month. Because the prices of different grades do not track the world price in parallel, using the more precise prices could potentially be important. Crude is globally traded and priced based on API gravity and location. Location provides information on the sulfur content of the oil since sulfur content is largely constant across the wells in a field.[18] Oil with low sulfur content, known as "sweet" crude, can be refined into light petroleum products such as gasoline or kerosene more cost effectively than high-sulfur, "sour" crude, which is typically processed into diesel or fuel oil.[19] For refining purposes, oil of the same API gravity and sulfur content is viewed as perfectly

[18]Refiners with the lowest transportation costs, typically those with the closest refineries, will purchase from a given field. As individual purchase and production decisions are too small to move transport costs, the difference between price at the wellhead and price at the refiner is taken to be independent of the decisions of individual firms.

[19]When oil prices are referred to in the popular media, the price frequently quoted is that of WTI, or UK Brent, both of which are light and sweet. The OPEC basket, which is a weighted average of crudes produced by OPEC nations, is a third benchmark and is both heavier and sourer than WTI or Brent.

substitutable regardless of origin.

While various congressional acts created the systems of regulation, decontrol, and excise taxation that provide the identifying variation in producer prices, the precise detailed rules of these legislative acts are found in the *Code of Federal Regulations* for each year. The details of price control assignment and WPT tax treatment are drawn from "Title 10: Energy" of the *Code of Federal Regulations* for each year, 1976-1980, and "Title 26: Internal Revenue" of the *Code of Federal Regulations* for each year, 1981-1985, which detailed the implementation of price control and WPT legislation.

## 4.2 Summary Statistics

Table 1 presents summary statistics for the full sample of 75,342 wells used to assess the impact of the regulatory and tax regimes of the late 1970s and 1980s. The average well produces 443 barrels of oil per month; conditioning on non-zero production raises the average roughly 50 percent. Approximately 28 percent of well-month observations report zero oil production either because the well is shut-in or because the well has not yet been completed. The production data are right skewed. The median well produces 113 barrels of oil per month, the 75th percentile well-month observation produces 428 barrels per month, and the 99th percentile observation produces 5,325 barrels per month. The within-well production variation, 2,859, is comparable to the overall standard deviation, 3,071. The average producer price during the period, \$18.3, is only 45 percent of the mean purchaser's price, with part of this difference attributable to the corporate income tax and part to the WPT. Producers for whom price controls were gradually phased out as they faced excise taxes under the WPT received the lowest—less than $12.30—after-tax prices. Producers of lighter oil received the highest prices in the sample—exceeding $32.00—at the end of 1979 and the beginning of 1980 prior to the introduction of the WPT. The within-well deviations in average after-tax price is 15 percent smaller than the overall variation in after-tax price, while the within-well and overall variation in pre-tax price is comparable. This discrepancy is driven by the differential regulatory and tax treatment of wells over the period. The average and median API gravities are 18.2 and 15.0, respectively, illustrating the heaviness of California oil. Finally, note that although there is considerable variability in API gravity in the sample (standard deviation of 6.8), each individual well has little variation in the API gravity of the oil it produces (standard deviation of 1.4).

# 5 Estimation Strategy

The way in which oil prices were decontrolled and oil production was taxed provide an unusual degree of variation in net-of-tax prices for often identical commodities across producers and over time. The decontrol of oil prices and the introduction of the WPT were policy changes implemented in tandem; oil prices were decontrolled by executive order while legislation enacting the excise tax was in committee in Congress. Figure 1 illustrates the timing of decontrol for different types of oil over the 1979 to 1981 period, starting with new oil and ending with old oil. These different categories of oil were also subject to different WPT tax rates and corresponding tax bases. Taken together these policy changes provide substantial deviations from the world market price.

The model described in Section 2 showed that the impact of a change in the after-tax price on the extraction rate for a long-lived well was a decreasing function of the cost parameter $c$. In other words, the cost parameter $c$ can be recovered from an estimate of the derivative of the extraction rate with respect to after-tax price. The impact of a level change in after-tax price on the extraction rate in levels is the empirical response of interest. The most natural regression framework that would yield estimates of $\frac{dq_t}{dp_t}$ is a simple linear model of the form:

$$q_{it} = \alpha + \beta \left(1 - \tau_{it}\right) p_{it} + X_{it}\gamma + u_i + \eta_{it} \tag{7}$$

where $q_{it}$ is extraction per month, $\left(1 - \tau_{it}\right) p_{it}$ is after-tax price, $X_{it}$ is a set of controls, and $u_i + \eta_{it}$ is the error term.[20] If the price ceilings and WPT tax rates were uncorrelated with the error term, the policy-based variation in after-tax price would yield an unbiased estimate of the tax response. But if after-tax price is correlated with an underlying well-specific component of the error term, $u_i$, then pooled ordinary least-squares estimation will yield biased estimates. The bias of the estimate will depend on the correlation between the omitted well-specific effect and the tax rate or price ceiling. Price ceilings and excise

[20]The after-tax price here is denoted by $\left(1 - \tau_{it}\right) p_{it}$ although in reality price controls and the WPT can both be described as taxes on a price basis, where the basis is the difference between the selling price of a barrel of oil and a statutory base price. In the case of price controls, the tax rate is 100 percent. This type of basis tax is structured like a capital gains tax and as in the capital gains literature, the marginal incentive to sell a barrel of oil is captured by $\left(1 - \tau_{it}\right) p_{it}$ and the basis is a transfer.

tax rates were not randomly assigned to wells by price controls and the WPT. Well characteristics (e.g. well age and stripper status) and oil characteristics (i.e.specific gravity), which are key determinants of the cost of extraction, were used to determine regulatory and tax treatment. Regulatory and tax treatment varied along these dimensions, in part in an effort to favorably treat operators who would be most adversely impacted by the policies. Thus, pooled ordinary least squares (OLS) estimates of equation (7) would be inappropriate.

Because extraction costs vary across wells even within tier, controls for the factors that determine tax treatment may not be sufficient to fully address heterogeneity in extraction costs. Instead, to isolate variation in the after-tax price not related to underlying differences in extraction costs, the analysis uses only within-well variation. Because of the considerable across time variation in after-tax price generated by the decontrol of oil prices and the levying of the WPT, there remains sufficient variation for each well over time to identify the supply response.

## 5.1 Residual Variation in After-Tax Price

Figure 3 plots different price measures for two wells. The real posted price line reports the real purchase price of the oil. The upper plot describes a relatively tax-disadvantaged well, and the lower plot describes a relatively tax-favored well.

The upper plot tracks an initially non-stripper well that was decontrolled gradually beginning in January 1980, then fully decontrolled in January 1981. The gradual decontrol can be seen in the nearly linear upward slope of the

Real Posted Price line starting in January 1980 and continuing until January 1981, when the price discontinuously jumps with full decontrol. This well was initially subject to a 70 percent WPT excise tax. The onset of the tax is the sudden downward jump in the After-Tax Price in March 1980. In October 1982, the well qualified as a stripper well and thus shifted to the slightly more tax-favored Tier II and became subject to a 60 percent excise tax rate; hence the uptick in the After-Tax Price. The decrease in posted price in January 1983 led to decreases in all price measures.

My estimation strategy removes well and time fixed effects. Purging the after-tax price measure of well fixed effects amounts to subtracting the well's average price over all periods from the price each period. Thus the Residual–Well FE line is the After-Tax Price line shifted downward by the well mean price. Further purging the post-well fixed effect residuals of time fixed effects amounts to then subtracting the average price each period over all wells. This two-way residual isolates relative within-well price variation, where relative means relative to all other wells in the sample that period. Thus, this well's two-way residual declines beginning in June 1979 as Tier III oil is fully decontrolled and market oil prices rise. The Residual–Well, Time FE line slopes upward between January 1980 and March of 1980 as the well began gradual decontrol, while already decontrolled wells faced less rapidly increasing prices. When the WPT is levied in March 1980, the two-way residual continues its upward trend because the increases in after-tax price due to continued decontrol more than offset the tax. Even after full decontrol in January 1981, the relative within-well after-tax price remains negative because this well faces the highest tax rate of all wells. The disadvantage narrows as posted prices in the Livermore field increased relatively faster than other fields. When the well is reclassified as a stripper well, there is a final uptick in the two-way residual as its WPT tax rate has fallen by 10 percentage points, which is short-lived as the Livermore price premium fades a few months later. From that point on, the two-way residual is near zero since declines in the posted price result in after-tax prices nearly equal to the average after-tax price for each well.

The lower plot tracks a relatively tax-favored well. The well did not produce oil in 1978 and is classified as a new well. The After-Tax Price line jumps upward in June 1979 when new oil was decontrolled and again several months later as posted prices reflected higher world prices. This Tier III well was initially subject to a 30 percent WPT tax rate, which was decreased by 2.5 percentage points each year starting in 1982 until the rate was 22.5 percent in 1984. Focusing on the two-way residual line, Residual–Well, Time FE, the fact that this well was tax-advantaged can be seen at several points. First, when this well was decontrolled in June 1979, the two-way residual is large and positive. The strong upward movement of posted prices beginning in 1980 is mitigated in the two-way residual since other wells were beginning decontrol and receiving higher after-tax prices during this time—the residuals do, however, remain above zero since this well was fully decontrolled. The residuals remains positive even after the introduction of the WPT because it was tax-favored.

Price variation generated by temporary taxes is likely to be perceived as having a persistence that differs from that generated by movements in price. If producers perceive price changes as having greater persistence than tax-driven changes, then supply elasticities generated by price changes would overstate the supply response to temporary taxes. Thus within-well variation in after-tax price, which retains both price- and tax-driven changes in after-tax price may not be the appropriate price measure for the analysis. To isolate price differences due only to differential decontrol and tax treatment, the data are purged of time-series variation in price. The plot for each well tracks this process of isolating relative within-well variation in after-tax price.

The key exclusion restriction of an identification strategy that purges after-tax prices of well and time averages is that, outside a time-invariant fixed factor, wells respond identically over time to changes in relative after-tax price. In other words, there are no time-varying well-specific factors, besides after-tax price, affecting well production.

# 6 Supply Response to After-Tax Price Changes

Table 2 presents OLS estimates of

$$q_{it} = \beta_1 \left(1 - \tau_t^{Corp}\right) \left(B_{igt} + \left(1 - \tau_t^{W}\right) \left(P_{gt} - B_{igt}\right)\right) + \beta_2 age_{it} + \chi_t + \delta_i + \epsilon_{it} \quad (8)$$

using the full sample of California oil wells. The dependent variable is the quantity of oil produced by well $i$ in month $t$. All specifications include well-level fixed effects to absorb level differences across wells in the operator's response to changes in net price—namely production cost heterogeneity. The sample includes all wells, whether or not they shut-in. Month-by-year dummies absorb mean production and price variation in each month. The tax-price elasticity is identified by within-well variation in after-tax price relative to the within-well variation of other wells. As wells age, their productivity declines, so an additional control for the age of the well, measured from its date of completion, is also included. Each column of Table 2 reports estimates from a different regression.

Column 1 reports results from an estimation of equation (8). The estimated coefficient on the after-tax price, $\beta_1$, implies that a one-dollar increase in the after-tax price leads the average well to produce 8.73 additional barrels of oil, a price elasticity of 0.237. Because well age is considered an important determinant of well productivity, column 2 adds a quadratic term in well age. The insignificant increase in the elasticity to 0.238 and the unchanged precision suggest that the linear control for well age is sufficient. Although over the course of a well's life there is little change in the API gravity of the oil extracted—the within-well standard deviation is only 1.4 degrees, less than 20 percent of overall variation—changes in API gravity could lead to changes in lifting costs if the changes are concentrated and thus large for wells that do experience changing gravity. Column 3 employs dummies and quadratic time trends for each decile of API gravity. The after-tax price coefficient is reduced by these added time-varying controls for oil quality, but the change, a reduction of the elasticity to 0.208, is statistically insignificant and economically minor.

The data cover all wells in the state of California, including wells located in the federally owned and privately leased NPR. The extracting firm in the NPR made productions decisions, but received less than the after-tax price for each barrel. Furthermore, as the firm only leased the reserves, it may not have taken the exhaustibility of the reserves into account in the same way that a reserve owner would. Thus, the production response of these NPR wells to changes in after-tax price may be smaller than the response for privately owned wells.[21] Column 4 presents estimates of a model identical to that of column 1, but drops the NPR wells from the sample. The point estimate is larger, which is consistent with the idea that the operator of the NPR wells was less price sensitive than other well operators. Though the estimated after-tax price elasticity is larger in terms of the point estimate, the difference is statistically insignificant. The NPR wells, in other words, were not significantly biasing the overall estimate of column 1.[22]

## 6.1 High and Low Marginal Cost Wells

Equation (5) makes clear that responses will be smaller for wells with high marginal costs, assuming that wells are far from the end of their economic life. Although the vast majority of wells in California are pumped, 13,198 wells produce oil based on their natural subsurface reservoir pressure for at least part of their lives. These flowing wells have low operating costs if they produce their natural flowing quantity, but it is very costly to adjust their production either upward or downward. Adjustment involves the installation of pumping

[21] The federal government opened the NPR to drilling in 1976. From 1976 until 1998 a private firm leased access to the field and extracted oil from the reserves. The oil was sold to private refiners at the after-tax price with the proceeds divided between the extracting firm and the federal government.

[22] The supply elasticity of the NPR wells, 0.173 (0.097) (not in table), is roughly 25 percent smaller than the overall elasticity, but statistically indistinguishable from the overall or non-NPR elasticities.

equipment to either increase subsurface pressure to accelerate extraction or to exert downward pressure to reduce the flow rate. In other words, very high costs of extraction rate adjustment make the operators of flowing wells unlikely to adjust their production levels in response to temporary changes in after-tax price.

Table 3 presents estimates of equation (8) separately for flowing and pumped wells.[23] Column 1 reports the baseline specification, which corresponds to column 1 of Table 2. Column 2 reports elasticity estimates for pumped wells.[24] Pumped wells—those for which production levels are more of a choice variable—are significantly more price elastic than the average well. A ten percent increase in after-tax price results in a 3.56 percent increase in oil production; the baseline specification implies only a 2.37 percent increase in production. Flowing wells, on the other hand, do not show a statistically significant production response to changes in after-tax price. The 95 percent confidence interval rules out supply responses larger than 0.072.

## 6.2 Well Closure Decisions

For wells near the end of their economic life, the post-tax profit from remaining reserves may not offset the losses they will incur during the tax period. Thus some well operators may choose to exit by shutting-in their wells. In fact, there was notable concern regarding response along this margin at the time

[23]Because some wells may initially flow but then need to be pumped, the number of wells in the flowing and pumped regressions exceeds the total number of wells.

[24]All elasticities are evaluated at average price and quantity, separately for pumped and flowing wells.

the tax was introduced.[25]

Table 4 reports conditional logit and OLS estimates of

$$S_{it} = \beta_1 \left(1 - \tau_t^{Corp}\right) \left(B_{igt} + \left(1 - \tau_t^{W}\right) \left(P_{gt} - B_{igt}\right)\right) + \beta_2 age_{it} + \chi_t + \delta_i + \epsilon_{it} \quad (9)$$

where $S_{it}$ is a dummy variable equal to one if the well is shut-in and $\beta_1$, the after-tax price coefficient, measures the percentage change in the probability of shut-in caused by a one-dollar increase in price. Columns 1-4 report marginal effects and semi-elasticities from conditional logit models. For comparison purposes, columns 5 and 6 report results from fixed effect OLS models. All of the regression models include well and time fixed effects to partial-out cost heterogeneity at the well-level and time-varying factors that affect production for all wells. If taxes motivate well operators to close their wells, then the short-run impact of the tax could translate into a long-run reduction in oil production as the reserves remaining in the shut wells are effectively lost.[26] As the predicted values of conditional logit models must lie between one and zero, the conditional logit model excludes wells that experience no variation in shut-in status. Identification again comes from relative within-well changes in after-tax price and the exclusion restriction requires that no time-varying well-specific factors affect production. Approximately 16.1 percent of well-month observations are shut-in during the 1977-1985 period; 27 percent of observations for wells that are neither always shut-in nor always open are

[25] For example, two months before the enactment of the tax, the *Wall Street Journal* ran a critical editorial about the proposed WPT titled "The Close-the-Wells Tax."

[26] Shut-in wells can be re-opened but rarely are because reopening is very costly and shut-in reduces the share of remaining reserves that is feasibly extractable. Only extraordinary price events typically trigger the re-opening of shut-in wells.

shut-in. The estimated after-tax price coefficient reported in column 1 of Table 4 suggests that a 10 percent increase in the after-tax price only reduces the rate of shut-in by 0.95 percentage point. This small estimated response suggests that a temporary tax like the WPT has a negligible impact on firms' shut-in decisions. This could be because the fixed costs of operating are small relative to profit from production or because few wells are near the end of their economic life. Of the wells producing in 1977, 69 percent are still producing in 1987, 44 percent are still producing in 1997 and 34 percent are still producing in 2007.

Column 2 adds a quadratic term in well age to better adjust for the decline in productivity that typically occurs over the life of the well. The estimates are virtually identical, again suggesting that a linear control for well age is sufficient. Adding quadratic time trends by API gravity decile increases the semi-elasticity by almost 25 percent to -0.117. Column 4 excludes wells from the NPR field. Dropping wells from the NPR field increases the point estimate of price response along the extensive margin, suggesting again that firms that lease government reserves are less price responsive than other operators, though the difference is statistically insignificant.[27]

The conditional logit model requires variation in the dependent variable for each well in the sample. To assess the impact of limiting the sample this way, I also report shut-in semi-elasticity estimates from fixed effect OLS models. For comparison, column 5 of Table 4 reports OLS estimates for the sample of wells with shut-in variation that is used to estimate the conditional logit model;

[27] In fact the after-tax price semi-elasticity of shut-in among NPR wells is only -0.0002 (0.0002).

column 6 reports OLS estimates from the full sample of wells. The estimate using the smaller sample is nearly three times as large as the estimate from the full sample and is similar to the conditional logit estimates. The estimates of columns 5 and 6 imply that, among operators that have meaningful discretion over the shut-in status of their wells, the effect of after-tax price on the shut-in decision is significantly larger. This suggests that the sample restrictions of the conditional logit model may be partly responsible for the higher semi-elasticity estimates of columns 1 through 4 relative to column 6. Though the conditional logit coefficients are twice as large as the full sample OLS coefficient, they remain small in magnitude. Taken together, these estimates suggest that the temporary tax does not lead to economically important rates of shut-in.

# 7 Reconciliation with Previous Estimates

The analysis presented in Section 6 uses well-level production data and after-tax prices carefully constructed from monthly field prices and complex regulatory and tax treatment rules. Previous studies, summarized in Table 5, estimate the supply response using aggregate national production and average pre-tax price. Examples of these studies include Griffin (1985), which uses quarterly data from 1971 to 1983, or Hogan (1989), which uses annual data over the longer 1966 to 1987 interval, or Jones (1990), which examines the 1983 to 1988 time period using quarterly data, or Dahl and Yücel (1991), which uses quarterly data from 1971 to 1987, or Ramcharran (2002), which uses annual data from 1973 to 1997.[28] These studies use time-series variation alone. As Table 5 reports, these time-series elasticity estimates are 60 and 80 percent smaller than my preferred elasticity estimate, 0.237 (0.029), when positive and significant, as in the cases of Hogan (1989) and Ramcharran (2002). Jones (1990) estimates a statistically insignificant supply elasticity of similarly small magnitude, 0.07 (0.04). In addition to these small positive elasticity estimates, Dahl and Yücel (1991) estimate an insignificant negative elasticity, and Griffin (1985) estimates a significant negative elasticity of -0.05 (0.02), which he suggests could be attributable to price controls.

The supply responses estimated in these studies may not be appropriate for assessing producer responses to excise taxes for three reasons. First, the use of the readily available but imprecise MER average pre-tax first purchase price series introduces measurement error in the price variable. Government policies created large deviations between after-tax price and world price that differed by well. These deviations are not reflected in the MER price series. The average effective WPT tax rate—the ratio of after-WPT but before-corporate income tax price to posted price—in my California data is 21.2 percent and ranges from zero, for wells for which the selling price eventually fell below their base price, to 56.4 percent, for wells in the highest WPT tax bracket. Since the variation in WPT rates across wells makes it impossible to construct the average after-tax price from the average pre-tax price, using the MER average first purchase price series introduces considerable measurement error for

[28]These studies estimated supply elasticities for total U.S. production as part of an examination of market structures among OPEC and non-OPEC countries; nonetheless most of these are the studies cited in supply elasticity surveys, such as Dahl and Duggan (1996).

a significant fraction of sample years used in previous studies. Ignoring taxes, especially when producer prices are reduced by the full or nearly full amount of the tax, leads to measurement error in the producer price variable and biases the resulting supply elasticity estimate downward. Table 6 reports analyses using MER average prices. Column 1 reports the results of my baseline specification, which corresponds to column 1 of Table 2. As column 2 of Table 6 shows, even in a within-well specification, using the MER prices instead of a well-specific after-tax price results in a small, statistically significant elasticity estimate of 0.021 (0.01).[29] The pooled and time-series regressions reported in columns 3 and 4 yield similarly small elasticity point estimates, though the pooled estimate, 0.024 (0.01), is statistically significant, while aggregating to the time-series yields an insignificant elasticity estimate of 0.017 (0.015). Taken together columns 2 through 4 of Table 6 make clear that the MER average pre-tax price series leads to considerably downward biased estimates comparable to those found by previous studies and roughly one-tenth the size of my estimates based on more accurate well-specific prices.

Second, this paper aims to assess the impact of taxes on oil production, so the elasticity estimate should be generated by after-tax price variation with a persistence similar to that of proposed tax policy. The persistence of after-tax price changes driven by movements in world price may be higher or lower than the persistence of changes in after-tax price driven by temporary taxes. As proposals have largely described temporary taxes, the temporary price

[29]Note that the preferred specification from my analysis using my constructed after-tax price also includes month-year fixed effects that are precluded by the within-month-year invariance of the MER time series.

changes induced by government policy isolated here are more appropriate than movements in world price. Finally, time-series regressions use aggregate totals of U.S. oil production as the dependent variable, introducing "aggregation bias" since well productivity is not homogeneous. U.S. oil wells lie along a gradient of productivity; when prices are higher the average producing well is less productive as some high cost wells are brought online. Aggregation will subsume this heterogeneity and bias the coefficient.

Detailed well-level data make it possible for me to assign each well a more accurate after-tax price. Well-level data also allow me to control for underlying heterogeneity in well productivity. Table 7 details the advantage of the micro-data. The regression results reported in Table 7 use the well-specific after-tax price as the key explanatory variables. The baseline estimate is repeated in column 1 of Table 7. Column 2 drops the month-year dummies, meaning that the within-month variation in price isolated in column 1 is combined with over-time variation in the pre-tax price, sans a linear time trend, to yield the 0.071 (0.014) elasticity estimate. In other words, adding the variation in world price shrinks the elasticity estimate by roughly 70 percent. Producers are less sensitive to pre-tax price variation, suggesting that producers may view underlying price variation as less persistent than variation due to temporary taxes. Columns 3 and 4, which report estimates from pooled OLS and time-series regressions, respectively, report negative elasticities. This surprising negative correlation is due to the nature of federal policies during decontrol and the WPT. Federal policy systematically treated less productive wells more favorably—both heavy oil wells, which face higher extraction costs, and stripper wells, which by definition are only marginally productive, were decontrolled earlier and assigned lower WPT rates than other wells. Thus wells that, on average, produced less oil received higher after-tax prices by fiat. While the well fixed effects of the specification of column 1 controls for these underlying differences, the pooled and time-series regressions of columns 3 and 4 reflect the negative correlation.

I construct a subsample of wells for which the after-tax price did not reflect such a fundamental difference in operating costs by dropping all heavy and stripper wells. In addition, I restrict the sample to wells that began production before 1982 to make the sample even more homogeneous, but this restriction is less empirically relevant.[30] This smaller sample retains cross-sectional variation in after-tax price since some wells were classified as favorably treated new oil wells while wells that produced oil in 1978 were classified as old oil wells. The key is that these remaining regulatory and tax treatment differences reflected less substantial systematic differences in production costs. Columns 5 and 6 report pooled and time-series estimates from regressions using this sample of more comparable wells. The elasticity estimates are statistically indistinguishable from each other and the baseline estimate of column 1.

# 8 Illustration of Lost Surplus Calculation

The elasticity estimates discussed in Section 6 suggest that operators react to temporary excise taxes by reducing production; according to the preferred

[30]The estimates of columns 5 and 6 are statistically similar using later first-production date sample limits.

specification, reported in column 1 of Table 2, a ten percent increase in the excise tax rate leads to a 2.4 percent reduction in production.

The simple model described in Section 2 and the estimates from Section 6 can be combined to illustrate the welfare cost of a temporary tax on an exhaustible resource. The illustrative calculation is based on two key assumptions: first, that the simple quadratic cost function captures the cost of extraction, and second, that wells are far enough from the end of their economic life that the second term of equation (5) can be ignored. The second assumption is supported by the results reported in Section 7: temporary price movements did not cause economically meaningful increases in the well shut-in rate, suggesting that few wells were very close to the end of their economic lives.

The welfare cost of an excise tax that applies only to domestic producers cannot be passed on to refiners or consumers, as Section 3 explains, meaning that consumer surplus is unaffected. The welfare cost of the tax, the reduction in producer surplus less the tax revenue, will be assessed here for a typical well, that is, a well that does not shut-in in reaction to the tax. The total welfare cost of the tax is thus:

$$\Delta PS+GR=\int_0^{T^1} e^{-rt}\left[\left(pq_t-\left(1-\tau_t\right)p\hat{q}_t\right)-\left(c\left(q_t\right)-c\left(\hat{q}_t\right)\right)\right]dt-\int_0^{t_1} e^{-rt}\tau p\hat{q}_t dt$$

Producer surplus, here, is reduced by three factors: the tax liability incurred due to the tax, the profit loss from delaying extraction, and the added cost of sub-optimal extraction of the reserves due to tilting of the extraction path in response to the tax.

For clarity, the pre-tax price of oil is assumed to be constant, so that $p_1 = (1 - \tau)\, p$ and $p_2 = p$. A tax at rate $\tau$ is in place from time 0 to time $t_1$. Once the tax has been introduced, the operator reduces his extraction rate before $t_1$, extending the life of his well by $dT$. For example, a 15 percent excise tax in place for five years extends the life of an initially 40-year well by approximately 0.75 of a year, assuming a pre-tax price of $25 and an interest rate of five percent.

The average impact of a change in after-tax price on oil production implies an average value of $c$ of the cost function used in the model described in Section 2, $c\,(q_t) = cq_t^2 + f$. For the baseline specification, column 1 of Table 2, the coefficient estimate, that is $\frac{dq_t}{dp_t}$, is 8.730 (1.082). This coefficient implies that, for the average well, $c = 0.0573$.

Table 8 reports the decrease in total surplus as a fraction of the government revenue raised from the tax—that is, the average cost of a dollar of revenue in terms of lost surplus. Additional details are reported in Appendix A. As we would expect, the estimates suggest that a temporary 15 percent excise tax reduces producer surplus more for short-lived wells. Overall the numbers suggest that the welfare cost of temporary taxes like the WPT is considerably smaller than a static estimate would suggest. Generally, the welfare loss falls precipitously for wells with longer economic lives (with the exception of a tax that lasts half the life of a 10-year well). The welfare loss of a one-year tax falls to 15 percent of raised revenue for a well with a 20-year life, and is ten percent for a 40-year well. Each dollar of revenue raised from the tax costs as little as 3 cents in the case of a five-year tax on a well with a 10-year life and as much as 25 cents in the case of a one-year tax on a well with a 10-year life.[31]

If the tax were permanent instead of temporary, the shape of the extraction path would not be affected, but the well would be abandoned with more oil remaining in the well if there were any fixed costs of production. In this case, the tax revenue raised would exactly offset the loss in producer surplus while the well is extracting since the production path is unaffected by a permanent tax. The welfare loss would arise from the permanent loss of oil due to early shut-in; the size of this loss depends on the fixed and variable costs of production.

These calculations only capture the change in producer surplus from raising revenue through oil excise taxes. In the case of the WPT, the revenues were earmarked for specific purposes—namely, conservation programs and subsidies for the production of synthetic fuels. The ultimate welfare impact of the decontrol and taxation of U.S. oil production hinges, not only on the welfare cost of the tax, but also on the welfare impact of these projects.

# 9 Conclusion

This paper uses new detailed data on the quantity of oil produced by wells in California to estimate the effect of tax- and price control-induced variation

[31] The deadweight loss declines between a three- and five-year tax for a 10-year well because the revenue gain of taxing such a large fraction of the well's production leads to a relatively larger revenue gain than producer surplus loss. For the other lives, even a five-year tax does not span enough of the well's life to see this pattern.

in oil prices on production decisions. The unusual cross-sectional variation in after-tax price provided by these government interventions allows for flexible controls for underlying changes in technology and other time-varying factors that affect oil production. The estimated coefficients imply an elasticity of approximately 0.24, suggesting that a 10 percent excise tax leads to a 2.4 percent reduction in domestic oil production.

I find that while oil production from existing wells is responsive to the after-tax price, the after-tax price has no appreciable impact on wells that flow in accordance with their natural subsurface pressure. Because these estimates imply that the producers alter their behavior in response to tax changes, they suggest that the incidence of an oil excise tax cannot be modeled simply as a tax on the rents of oil producers.

Under the assumption that world oil prices are insensitive to U.S. producer decisions, an excise tax on U.S. producers will reduce producer profits—a reduction only partly offset by the government revenue raised from the tax. Calculations suggest that the average dollar of revenue raised from an excise tax on California oil producers costs between \$0.03 and \$0.25 in lost producer surplus, depending on the original life of the well and the duration of the temporary tax.

The supply responses measured here are potentially relevant to the evaluation of a range of fiscal policies that could affect crude oil production. These include changes in gasoline excise taxes, the introduction of carbon taxes, and oil import fees that could raise the price received by domestic oil producers.

The empirical findings bear on short-run production decisions, and it is important to remember several cautions about their broader interpretation. First, temporary taxes are likely to delay exploration and development activities—the taxes delay profits, so firms will want to delay investments. This response margin is not captured by the analysis presented above. Though exploration within the continental U.S. has waned over time, firms could delay the exploration and development of offshore reserves in reaction to temporary taxes, making the inclusion or exemption of these areas from proposed taxes a policy question with potentially important ramifications.

Second, California wells and the oil they produce have higher extraction costs than the average U.S. well. Because the oil is of such high specific gravity it is costly to extract, or lift, to the surface. The extraction rules derived in Section 2 imply that the estimates from California may well provide a lower bound on after-tax responsiveness for the average American well.

Finally, the estimates generated here are identified by policies from the late 1970s and 1980s and are thus historic. Although most major technological breakthroughs in the oil industry over the last 30 years, such as horizontal drilling methods, have affected drilling rather than pumping, technological changes that have improved extraction efficiency may make these estimates less applicable to current proposals. Taken together, however, the evidence presented here suggests that while excise taxes on crude do reduce producer surplus, they may well be more a more efficient source of revenue than current sources such as labor income taxes.

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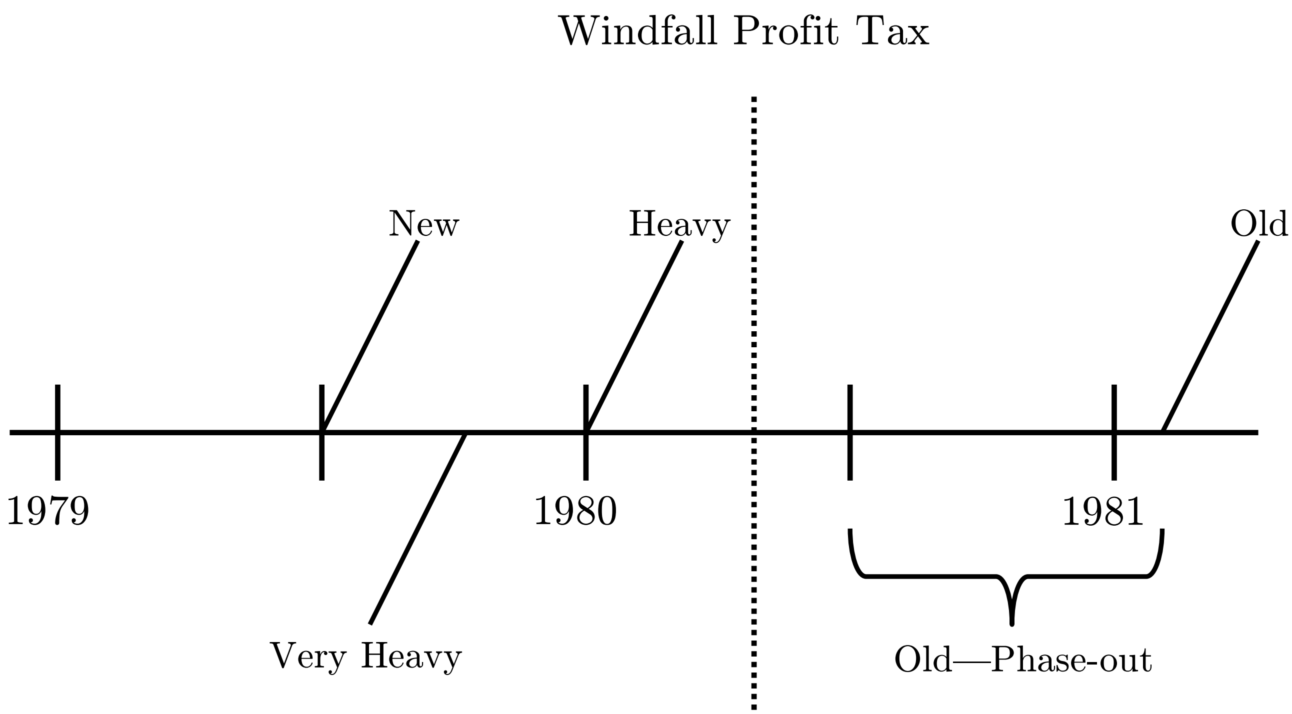
Figure 1: Timeline of Price Decontrol and Enactment of 1980 Windfall Profit Tax




**New oil** (oil extracted from wells that did not produce oil in 1978) was decontrolled in June 1979.

**Very heavy oil** (oil with an API gravity of less than 16 degrees) was decontrolled in September 1979.

**Heavy oil** (oil with an API gravity of less than 20 but at least 16 degrees) was decontrolled in January 1980.

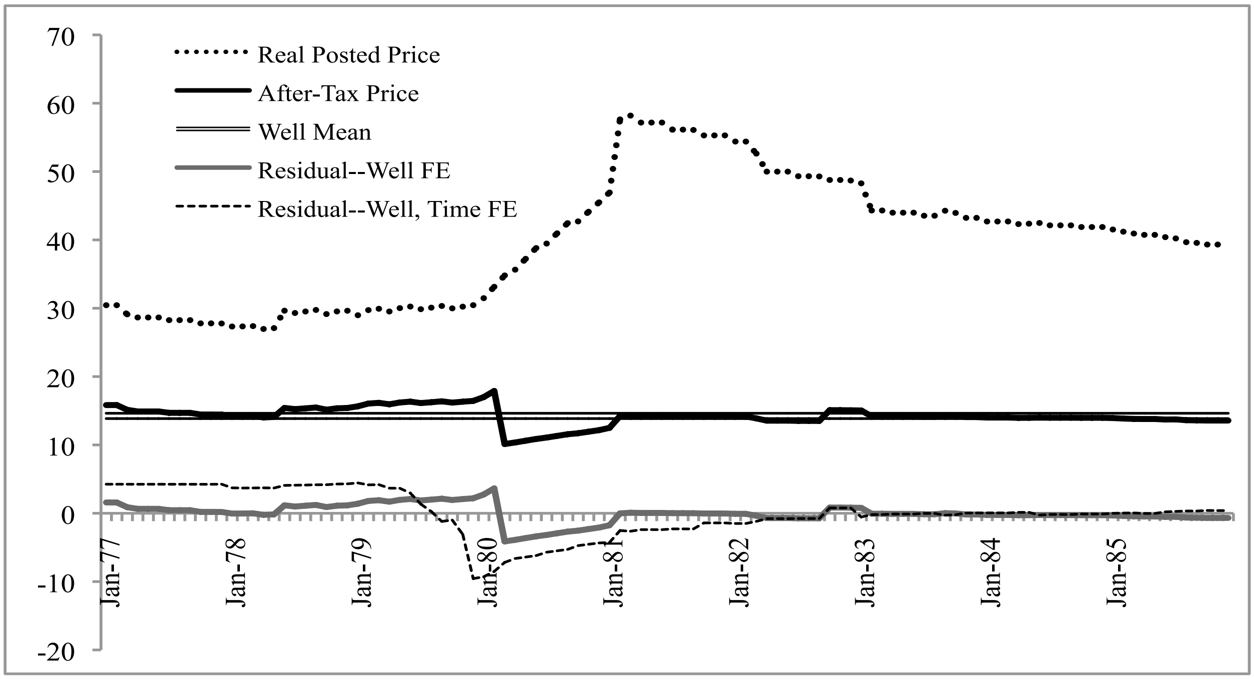
**Old oil** (oil extracted from wells that produced oil in 1978) was gradually decontrolled between January 1980 until January 28, 1981. During the phase-out period, old oil sold at a price that was equal to the weighted average of the world market price and the price control price ceiling, with the weight on the world market price growing by 0.046 each month. Old oil was fully decontrolled by President Reagan on January 28, 1981. February 1981 was the first full month in which old oil was decontrolled.

**1980 Windfall Profit Tax** was signed into law April 2, 1980 and went into effect immediately

Figure 2: Prices, Before and After Taxes and Fixed Effects, Two Wells

Well 120005: Livermore Field, Operator: Hershey Oil Corp.

Old oil, API gravity of 23; stripper starting Oct. 1982 (70% tax rate until Oct. 1982, then 60 percent)




Well 1300071: Brentwood Field, Operator: Occidental Petroleum Corp.

New oil, API gravity of 40.7; never stripper (30% tax rate until 1982, then gradual decrease to 22.5%)

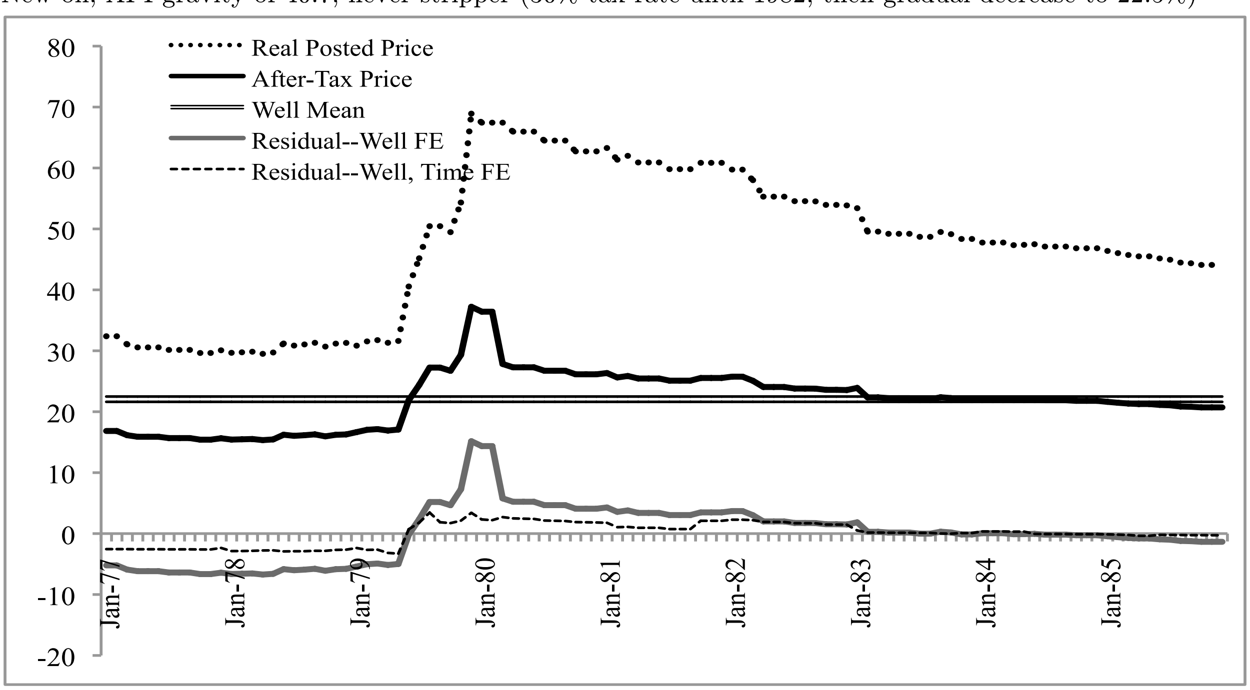


Table 1: Summary Statistics

| | Mean | Standard Deviation | |
|---|---|---|---|
| | | Overall | Within-Well |
| Oil Production (barrels) | 443.3 | 3071.1 | 2858.5 |
| Oil Production if Producing | 666.1 | 3745.0 | 3460.5 |
| After-tax Price ($) | 18.3 | 4.1 | 3.5 |
| WPT Tax Rate | 0.21 | 0.24 | 0.19 |
| Purchase Price | 41.1 | 10.1 | 9.78 |
| API Gravity (degrees) | 18.2 | 6.8 | 1.4 |
| Number of Wells | 75,342 | | |
| Observations | 6,517,140 | | |

Note: These summary statistics describe the well-month observations that comprise the sample for the regression analyis. Not all 75,342 wells report 108 observations since new wells are drilled and old wells are abandoned during the sample period.

Table 2: Regressions of Quantity Produced on After-Tax Price

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| After-tax Price | 8.730 | 8.741 | 7.659 | 9.598 |
| | (1.082) | (1.082) | (0.979) | (0.765) |
| Well Age | -1.269 | -1.228 | 6.531 | -1.258 |
| | (0.069) | (0.081) | (1.885) | (0.050) |
| Well Age Squared | | -(0.0003) | | |
| | | (0.0002) | | |
| Well Dummies | Y | Y | Y | Y |
| Time Dummies | Y | Y | Y | Y |
| API Gravity Decile Dummies | N | N | Y | N |
| API Gravity Decile Time Trends | N | N | Y | N |
| After Tax-price Elasticity | 0.237 | 0.238 | 0.208 | 0.261 |
| | (0.029) | (0.029) | (0.027) | (0.021) |
| Number of Wells | 75,342 | 75,342 | 75,342 | 73,548 |
| Observations | 6,517,140 | 6,517,140 | 6,517,140 | 6,350,820 |

Note: This table presents OLS estimates of

$$q_{it} = \beta_0 + \beta_1(1-\tau_t^C)(B_{igt} + (1-\tau_{igt}^W)(P_{gt} - B_{igt})) + \beta_2 age_{it} + \chi_t + \delta_i + \varepsilon_{it}$$

The dependent variable is the quantity of oil produced by well $i$ in month $t$. After-Tax Price is the posted price at which oil from well $i$ was sold during month $t$, net of corporate and Windfall Profit taxes. The coefficient on After-Tax Price, $\beta_1$, reports the supply response of operators to net price.

Column 1 is the baseline specification; it includes time and well dummies and a control for well age. Column 2 adds a quadratic well age term. Column 3 includes separate quadratic time trends, slopes, and coefficients, by API gravity decile. Column 4 drops all observations from the federal Naval Petroleum Reserve. The elasticity calculations for all specifications is the product of the coefficient estimate and the ratio of average after-tax price to average quantity for the sample of 4,681,973 producing oil wells.

All heteroskedasticity robust standard errors are clustered at the individual well level.

Table 3: Regressions of Quantity Produced on After-Tax Price
Flowing vs. Pumped Wells

| | (1) | (2) | (3) |
|---|---|---|---|
| | Baseline | Pumped | Flowing |
| After Tax-price Elasticity | 0.237 | 0.356 | -0.101 |
| | (0.029) | (0.024) | (0.088) |
| p-value | 0.000 | 0.000 | 0.253 |
| 95% Confidence Intervals | [0.180, 0.295] | [0.083, 0.108] | [-0.274, 0.072] |
| | | | |
| After-tax Price | 8.730 | 11.520 | -12.180 |
| | (1.082) | (0.784) | (10.649) |
| Well Age | -1.269 | -1.570 | -0.377 |
| | (0.069) | (0.055) | (0.866) |
| Well Dummies | Y | Y | Y |
| Time Dummies | Y | Y | Y |
| | | | |
| Number of Wells | 75,342 | 72,797 | 13,198 |
| Observations | 6,517,140 | 5,698,198 | 818,942 |

Note: This table presents OLS estimates of

$$q_{it} = \beta_0 + \beta_1(1-\tau_t^C)(B_{igt} + (1-\tau_{igt}^W)(P_{gt} - B_{igt})) + \beta_2 age_{it} + \chi_t + \delta_i + \varepsilon_{it}$$

The dependent variable is the quantity of oil produced by well $i$ in month $t$. After-Tax Price is the posted price at which oil from well $i$ was sold during month $t$, net of corporate and Windfall Profit taxes. The coefficient on After-Tax Price, $\beta_1$, reports the supply response of operators to net price.

All specifications include well and time dummies. Column 1 is the baseline specification; it reports the same estimates as column 1 of Table 2. Column 2 restricts the sample to only pumped wells. Column 3 restricts the sample to only flowing wells, which do not require mechanical lift to produce oil. The elasticity calculations for all specifications is the product of the coefficient estimate and the ratio of average after-tax price to average quantity for the estimation sample of producing oil wells.

All heteroskedasticity robust standard errors are clustered at the individual well level.

Table 4: Conditional Logit Models of Well Shut-in Decisions

| | (1) | (2) | (3) | (4) | (5) | (6) |
|---|---|---|---|---|---|---|
| | Cond. Logit | Cond. Logit | Cond. Logit | Cond. Logit | OLS | OLS |
| | Shut-in Var. | Shut-in Var. | Shut-in Var. | No NPR | Shut-in Var. | Full Sample |
| After-tax Price | -0.0052 | -0.0052 | -0.0064 | -0.0060 | -0.0043 | -0.0015 |
| | (0.0008) | (0.0008) | (0.0002) | (0.0009) | (0.0004) | (0.0002) |
| Well Age | 0.0126 | 0.0126 | 0.0455 | 0.0121 | 0.0014 | 0.0005 |
| | (0.0007) | (0.0007) | (0.0008) | (0.0007) | (0.0000) | (0.0000) |
| Well Age Squared | | 0.000 | | | | |
| | | (0.0000) | | | | |
| Well Dummies | Y | Y | Y | Y | Y | Y |
| Time Dummies | Y | Y | Y | Y | Y | Y |
| API Gravity Decile Dummies | N | N | Y | N | N | N |
| API Gravity Decile Time Trends | N | N | Y | N | N | N |
| After Tax-price Semi-Elasticity | -0.095 | -0.095 | -0.117 | -0.111 | -0.080 | -0.027 |
| | (0.0148) | (0.0148) | (0.0037) | (0.0169) | (0.0078) | (0.0034) |
| Number of Wells | 29,297 | 29,297 | 29,297 | 27,989 | 29,297 | 75,342 |
| Observations | 2,694,267 | 2,694,267 | 2,694,267 | 2,571,746 | 2,694,267 | 6,517,140 |

Note: This table presents conditional logit estimates of

$$S_{it} = \beta_0 + \beta_1(1-\tau_t^C)(B_{igt} + (1-\tau_{igt}^W)(P_{gt} - B_{igt})) + \beta_2 age_{it} + f(t) + \delta_i + \varepsilon_{it}$$

The binary dependent variable is one if well $i$ is shut-in in month $t$ and zero if it is not. After-Tax Price is the posted price at which oil from well $i$ was sold during month $t$, less corporate and Windfall Profit taxes. The coefficient on After-Tax Price, $\beta_1$, reports the extensive response of operators to net price.

Column 1 includes a full set of month by year dummies and well dummies. Column 2 adds a quadratic term in well age. Column 3 adds dummies and quadratic time trends for each API gravity decile. Column 4 excludes observations from the federally owned NPR. Column 5 estimates an OLS model with well and time fixed effects using the same sample of wells that experience variation in shut-in status. Column 6 estimates the fixed effect OLS model using the full sample of wells. The semi-elasticity calculations for all specifications is the product of the marginal effect estimate and average after-tax price.

All standard errors are clustered at the individual well level.

Table 5: U.S. Supply Elasticities From Previous Studies

| Study | Sample Period | Data | Elasticity Estimate |
|---|---|---|---|
| Griffin (1985) | 1971Q1 - 1983Q3 | Quarterly data on total U.S. production and average pre-tax posted price from 1971Q1 to 1976Q2, average pre-tax first purchase price from 1976Q3 to 1983Q3. No controls. | -0.05 (0.02) |
| Hogan (1989) | 1966 - 1987 | Annual data on total U.S. production and average pre-tax first purchase price. | 0.09 (0.03) |
| Jones (1990) | 1983Q3 - 1988Q4 | Quarterly data on total U.S. production and average pre-tax first purchase price. No controls. | 0.07 (0.04) |
| Dahl and Yücel (1991) | 1971Q1 - 1987Q4 | Quarterly data on total U.S. production and average first purchase price. Added controls for production cost, wells drilled, U.S. income, and world oil production. | -0.08 (0.06) |
| Ramcharran (2002) | 1973 - 1997 | Annual data on total U.S. production and average pre-tax first purchase price. Linear time trend included. | 0.05 (0.02) |

Note: These studies estimated supply elasticities for total U.S. production as part of an examination of market structures among OPEC and non-OPEC countries; nonetheless most of these are the studies cited in supply elasticity surveys, such as Dahl and Duggan (1996). All of these analyses rely on time-series data for the U.S. All of these models were estimated in logs. Standard errors are in parentheses.

Table 6: Alternative Specifications Using National Average Price Series

| | (1) | (2) | (3) | (4) |
|---|---|---|---|---|
| | Baseline | Within Well | Pooled | Time-Series |
| WTI Price | 8.730 | 0.320 | 0.365 | 11,223 |
| | (1.082) | (0.148) | (0.153) | (10,036) |
| Well Age | -1.269 | - | - | - |
| | (0.069) | - | - | - |
| Time | - | | -(0.147) | 48,874 |
| | - | | 0.081 | (4,468) |
| Well Dummies | Y | Y | N | N |
| Time Dummies | Y | N | N | N |
| After Tax-price Elasticity | 0.237 | 0.021 | 0.024 | 0.017 |
| | (0.029) | (0.010) | (0.010) | (0.015) |
| p-value | 0.000 | 0.030 | 0.017 | 0.263 |
| Number of Wells | 75,342 | 75,342 | 75,342 | 75,342 |
| Observations | 6,517,140 | 6,517,140 | 6,517,140 | 6,517,140 |

Note: This table presents OLS estimates of the equation,

$$q_{it} = \beta_0 + \beta_1 \overline{P}_t + f(t) + \varepsilon_{it}$$

The dependent variable is the quantity of oil produced by well $i$ in month $t$ in the baseline, within-well, and pooled specifications; the dependent variable is the total quantity produced across all wells in month $t$ in the time-series specifications. Average price is the average pre-tax first purchase price from the Department of Energy's *Monthly Energy Review* price series. The coefficient on After-Tax Price, $\beta_1$, reports the supply response of operators to this price measure.

Column 1 is the baseline specification where the price variable is the well specific after tax price, corresponding to column 2 of Table 2; it includes time and well dummies and a control for well age. Column 2 uses average pre-tax price from the *Monthly Economic Review* (MER) price series rather than the well-specific after-tax price and drops the time dummies; it controls linearly for time and omits the well age control to better match previous time-series specifications. Column 3 excludes both time and well dummies but retains the linear time control. Column 4 reports estimates from a time-series regression of total production across all wells each month on MER average pre-tax price. As in the previous literature no attempt to correct for autocorrelation is made. The elasticity calculations for 1, 2, and 3 are the product of the coefficient estimate and the ratio of average after-tax price to average quantity for the sample of 4,681,973 producing oil wells. For column 4 the in-sample average

For columns 1 through 3, heteroskedasticity robust standard errors are clustered at the individual well level.

Table 7: Alternative Specifications Using After-tax Price

| | (1) | (2) | (3) | (4) | (5) | (6) |
|---|---|---|---|---|---|---|
| | Baseline | Within Well | Pooled | Time-Series | Pooled | Time-Series |
| After-tax Price | 8.730 | 2.617 | -19.676 | -58,302 | 13.432 | 158,262 |
| | (1.082) | (0.500) | (1.015) | (39,283) | (4.946) | (44,607) |
| Well Age | -1.269 | - | - | - | - | - |
| | (0.069) | - | - | - | - | - |
| Time | - | -1.260 | 0.315 | 0.098 | -3.476 | -56,305 |
| | - | (0.080) | (0.081) | (0.007) | (0.362) | (2,164) |
| Well Dummies | Y | Y | N | N | N | - |
| Time Dummies | Y | N | N | N | N | - |
| After-tax Price Elasticity | 0.237 | 0.071 | -0.535 | -0.036 | 0.149 | 0.208 |
| | (0.029) | (0.014) | (0.028) | (0.024) | (0.055) | (0.059) |
| p-value | 0.000 | 0.000 | 0.000 | 0.138 | 0.000 | 0.000 |
| Number of Wells | 75,342 | 75,342 | 75,342 | - | 20,699 | - |
| Observations | 6,517,140 | 6,517,140 | 6,517,140 | 108 | 1,090,659 | 108 |

Note: This table presents OLS estimats of the equation,

$$q_{it} = \beta_0 + \beta_1(1-\tau_t^C)(B_{it} + (1-\tau_{it}^W)(P_t - B_{it})) + f(t) + \varepsilon_{it}$$

The dependent variable is the quantity of oil produced by well $i$ in month $t$ in the baseline, within-well, and pooled specifications; the dependent variable is the total quantity produced across all wells in month $t$ in the time-series specifications. After-Tax Price is the posted price at which oil from well $i$ was sold during month $t$, net of corporate and Windfall Profit taxes. The coefficient on After-Tax Price, $\beta_1$, reports the supply response of operators to net price.

Column 1 is the baseline specification, corresponding to column 2 of Table 2; it includes time and well dummies and a control for well age. Column 2 drops the time dummies; it instead controls linearly for time and omits the well age control to better match previous time-series specifications. The coefficient on after-tax price in a within-well specification that controls linearly for well age but not for time is 2.617 (0.500), within rouding error of the estimate reported in column 2. Column 3 excludes both time and well dummies but retains the linear time control. Column 4 reports estimates from a time-series regression of total production across all wells each month on average after-tax price. As in the previous literature no attempt to correct for autocorrelation is made. Columns 5 and 6 restrict the sample to non-heavy, non-stripper wells that began production prior to January 1982 in an attempt to construct a sample of more comparable wells. These wells were treated differently by decontrol policies and the WPT as some are new wells and others are old wells. Column 5 reports estimates from a specification identical to that of column 3 but uses this smaller, more comparable sample. Column 6 reports estimates from a specification identical to that of column 4 but again on the smaller sample of non-heavy, non-stripper wells that are both new and old. The elasticity calculations for 1, 2, 3, and 5 are the product of the coefficient estimate and the ratio of average after-tax price to average quantity for the sample of 4,681,973 producing oil wells. For columns 4 and 6 the in-sample average after-tax price and oil production are used to construct the elasticity.

level.

Table 8: Ratio of the Change in Surplus to Government Revenue Raised From the Introduction of a 15% Temporary Excise Tax

| | Duration of Temporary Tax ($t_1$) | | | |
|---|---|---|---|---|
| $T^0$ | 1 | 2 | 3 | 5 |
| 10 | -0.25 | -0.21 | -0.15 | -0.03 |
| 15 | -0.19 | -0.18 | -0.16 | -0.13 |
| 20 | -0.15 | -0.15 | -0.14 | -0.13 |
| 25 | -0.13 | -0.13 | -0.13 | -0.12 |
| 30 | -0.12 | -0.12 | -0.12 | -0.11 |
| 40 | -0.10 | -0.10 | -0.10 | -0.10 |

Note: This table reports the ratio of the change in total surplus, the loss in producer surplus (*PS*) less government revenue (*GR*), over the government revenue, for a single well whose cost function parameter $c = 0.0573$, which corresponds to the average elasticity response reported in column 1 of Table 2. The pre-tax price is assumed constant and equal to \$25. The interest rate is 5 percent. Producer surplus before the tax is calculated using the following equation:

$$PS^0 = \int_0^{T^0} e^{-rt}\left[p\left(\frac{p}{2c}-\frac{pe^{-r(T^0-t)}}{2c}\right)-c\left(\frac{p}{2c}-\frac{pe^{-r(T^0-t)}}{2c}\right)^2\right]dt = \frac{p^2}{4cr}\left(1-e^{-rT^0}\right)^2$$

Producer surplus after the tax is calculated using the following equation:

$$PS^1 = \int_0^{t_1} e^{-rt}\left[(1-\tau)p\left(\frac{(1-\tau)p}{2c}-\frac{pe^{-r(T^1-t)}}{2c}\right)-c\left(\frac{(1-\tau)p}{2c}-\frac{pe^{-r(T^1-t)}}{2c}\right)^2\right]dt + \int_{t_1}^{T^1} e^{-rt}\left[p\left(\frac{p}{2c}-\frac{pe^{-r(T^1-t)}}{2c}\right)-c\left(\frac{(p}{2c}-\frac{pe^{-r(T^1-t)}}{2c}\right)^2\right]dt$$

$$= \frac{p^2}{4cr}\left(\left((1-\tau)^2-1\right)\left(1-e^{-rt_1}\right)+\left(1-e^{-rT^1}\right)^2\right)$$

Government revenue from the temporary tax is calculated using the following equation:

$$GR = \int_0^{t^1} e^{-rt}\tau p\left(\frac{(1-\tau)p}{2c}-\frac{pe^{-r(T^1-t)}}{2c}\right)dt = \frac{\tau p^2}{2c}\left(\frac{(1-\tau)}{r}\left(1-e^{-rt_1}\right)-e^{-rT^1}t_1\right)$$

where $T^1 = T^0 + dT$, the new economic life of the well. The original economic life of the well, $T^0$, varies down the rows while the duration of the temporary tax, $t_1$, varies along the columns. The entries are $(PS^0 - PS^1 + GR)/GR$.