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Taxation and the Extraction of Exhaustible Resources

Evidence from California Oil Production

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

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Abstract

Rapid increases in oil prices in 2008 led some to call for special taxes on the oil industry. Because oil is an exhaustible resource, however, the effects of excise taxes on production or on reported producer profits may be more complex than in many other markets. This paper uses well-level production data on California oil wells for the period 1977-2008, along with the rich variation in producer prices induced by federal oil taxes and pre-1980 price controls, to estimate how temporary taxes affect oil production decisions. Theory suggests that temporary taxes could lead producers to shut wells, and more generally that they create strong incentives for retiming production to minimize tax burdens. The empirical estimates suggest that extensive responses to changes in after-tax prices are rare, meaning that wells are rarely shut, but they also suggest substantial retiming of production for operating wells. While the estimates vary with specifications, the elasticity of oil production with respect to the after-tax price is estimated to fall between 0.208 and 0.261. 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 0.1 and 1 percent of the no-tax surplus or 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.

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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. The effects of taxes on the extraction of exhaustible resources like oil may be of increasing importance as proposals to tax fossil fuels emerge as part of the climate change debate.

Despite the importance of estimates of the elasticity of U.S. supply for assessing the impact of policy changes—like the decontrol of oil prices in the late 1970s or current policy considerations like the levying of new oil industry taxes or imposing an oil import fee—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 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—that were within the

[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)

wide range of estimates 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. The data come from mandatory monthly filings by well operators to the California Department of Conservation Division of Oil, Gas and Geothermal Resources. I construct a dataset of 30,025,957 observations describing 140,672 wells. These data cover all onshore production between 1977 and 2008; 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 the status (whether it is capable of producing or 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 variation 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 three difficulties. First, the use of the readily available but non-representative Department of Energy Monthly Energy Review (MER) average pre-tax first purchase price series introduces

[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.

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.

Second, the persistence of tax and price variation may differ; the elasticity estimate and resulting cost parameter estimate used to evaluate the welfare cost of excise taxes on oil extraction should be generated by after-tax price variation of similar persistence as proposed tax policy.[4] As policy proposals largely describe temporary taxes, the temporary price changes induced by government policy isolated here may be more appropriate than movements in world price. In fact, comparing a supply elasticity estimate (and standard error) using my data that purges variation in world price through month-year fixed effects, 0.237 (0.029), to an estimate using my data that retains variation in world price, 0.071 (0.014), suggests that firms are less sensitive to pre-tax price variation.

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.

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

[4] If variation in world price is more persistent than temporary tax variation, then including price variation in the after-tax price variation used to generate elasticity estimates will lead to an over-estimate of the elasticity since firms are responsive to longer-term changes in after-tax price. If tax variation were more persistent than world price variation, the opposite would be true.

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.[5] 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. Potential additional adjustment on the exploration margin may make the estimates reported here a lower bound on the full elasticity.

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; the main specification shows that 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 one and five percent of the no-tax surplus, depending on the original life of the well and the duration of the temporary tax. On average, each dollar of tax revenue raised reduces producer surplus by \$1.13 to \$1.66.

The paper proceeds as follows. Section 2 describes a simple model of the impact of excise taxes on the extraction of an exhaustible resource. Relevant background information on the U.S. and California oil industries and the relevant institutional knowledge regarding the decontrol of oil prices and the introduction of temporary federal excise taxes are discussed in Section 3. Section 4 describes the new rich production and price data I assembled. Section 5 details the estimation strategy. Section 6 presents the estimates of the supply

[5] 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.

response. Section 7 assesses how after-tax price affects the well closure decision. Section 8 demonstrates the value of micro-data and reconciles my elasticities with the much smaller elasticities estimated in prior studies. Section 9 illustrates how the empirical estimates of Section 6 and the model from Section 2 can be combined to assess the welfare cost of excise taxes on domestic oil production. Section 10 concludes and discusses directions for future research.

2 Taxes and the Extraction of Exhaustible Resources

This section focuses on the well operator's extraction decision. Subsection 2.1 presents a simple model of the oil well operator's problem, highlighting that exhaustibility reduces the extraction rate relative to production from an inexhaustible resource. Subsection 2.2 discusses the effects of excise taxes in the context of the model, which have been recently proposed in reaction to rapidly increasing oil prices.

2.1 The Extraction Problem

The well operator chooses an extraction path to maximize profit, taking into account the exhaustibility of the reserves of his well. Operators are assumed to be price-takers with known reserves; as in the Hotelling (1931) model, the operator chooses an extraction path by dynamically optimizing the present discounted value of total profit from extraction over the life of the well.[6] 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.

Exhaustibility

For an exhaustible resource, the intertemporal sum of services from a given stock is finite.[7]

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

[7] The sum of services is still finite even if the resource is recyclable since less than the full quantity can be recovered each time the output is recycled. Recycling, of course, is not relevant in the case of oil.

Exhaustibility in effect makes extraction a "pump today or pump tomorrow" decision for the operator. Extracting a unit today has an opportunity cost: the unit cannot be extracted in the future. This opportunity cost creates an incentive for holding the resource *in situ*, tempering the incentive to extract and sell. In the model, the operator of a drilled well is assumed to know his reserve level with certainty, thus exhaustibility means that the total amount of oil extracted from the well cannot exceed his initial known reserves, R_0:

$$\int_0^\infty q_t dt \leq R_0 \tag{1}$$

where q_t is the extraction rate at time t. In addition q_t is assumed to be non-negative, ruling out pumping oil into the reservoir.

Exhaustibility

For simplicity, it is assumed that the full price path is known at time 0. Because the operator is a price-taker, his problem is

$$\max_{\langle q \rangle} \int_0^\infty e^{-rt} \left[p_t q_t - c\left(q_t\right) \right] dt \tag{2}$$

subject to

$$\int_0^\infty q_t dt \leq R_0 \text{ and } R_t \geq 0 \tag{3}$$

where p_t is the price, $c\left(q_t\right)$ is the cost of extraction, and R_t is the reserve level at time t. Though the operator's problem is dynamic, the shadow-value of reserves associated with the exhaustibility constraint along the optimal extraction path is time invariant. The non-negativity constraint can be ignored given the linearity of revenues and the convexity of cost in q_t—if q_t is always non-negative and total extraction does not exceed initial reserves, then the reserve level will always be positive. Thus, the problem can be written as a Hamiltonian

with a single constraint

$$\Lambda\left(q_t, \lambda_t\right) = \int_0^T e^{-rt}\left[p_t q_t - c\left(q_t\right)\right] dt - \lambda_t \left[\int_0^T q_t dt - R_0\right] \tag{4}$$

where T is the time at which all profitable oil has been extracted and the economic limit of the well has been reached. The first-order condition with respect to q_t

$$e^{-rt}\left(p_t - c'\left(q_t\right)\right) - \lambda\left(t\right) = 0 \tag{5}$$

implicitly defines the optimal extraction rate at each time t, q_t, as a function of the price at time t, p_t, the interest rate, r, and the shadow value of an incremental addition to reserves, λ. The second necessary condition

$$\dot{\lambda} = -\frac{\partial \Lambda\left(q_t, \lambda\left(t\right)\right)}{\partial R_t} = 0 \tag{6}$$

implies that the multiplier, λ, is constant. The shadow value of reserves is pinned down by the terminal condition. At time T the economic life of the well has been reached and the extraction rate falls to zero.[8] The transversality condition, $\Lambda\left(T\right) = 0$, combined with first-order condition at time at time T, imply that q_T is the production level that equates the marginal and average costs of production. If the marginal cost of producing q_T, $c'\left(q_T\right)$, exceeds the price, then the producer will opt to not produce and shut-in and exit instead. Plugging the terminal production quantity, q_T into the static optimization condition at time T, the shadow value of reserves is pinned down:

$$\lambda = e^{-rT(\mathbf{p})}\left(p_T - c'\left(q_T\right)\right) \tag{7}$$

[8]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 jumps to zero.

where the life of the well, T, is a function of the price path, $\mathbf{p}$, since higher average prices will accelerate extraction and shorten well life. The exact shape of the extraction path is determined by the marginal cost of extraction and the discount factor, with the shutdown condition, the equality of marginal and average cost, pinning down the extraction amount at time T. The reserves will be fully exhausted at time T 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. Intuitively, once he has paid the fixed cost to produce in the last period, he will produce the remaining quantity (which is, by optimality of the extraction path, less than the quantity that equates price and marginal cost).

The Cost of Extraction

Even after the completion of the well, extracting oil is 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.

The Optimal Extraction Path

Given the quadratic cost function, the optimal extraction rate and shadow value of reserves

are

$$e^{-rt}\left(p_t - 2cq_t\right) - \lambda = 0 \tag{8}$$

$$\lambda = e^{-rT}\left(p_T - 2\sqrt{fc}\right) \tag{9}$$

Combining equations 8 and 9, the optimal extraction at time t is

$$q_t^* = \frac{p_t}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left(p_T - 2\sqrt{fc}\right)}{2c} \tag{10}$$

where again the economic life of the well, T, is a function of the price path, $\mathbf{p}$; a higher price today will lead to a faster extraction rate and a shorter well life. More specifically, $T(\mathbf{p})$ is implicitly defined by the exhaustibility constraint

$$\int_0^T \left[\frac{p_t}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left(p_T - 2\sqrt{fc}\right)}{2c}\right] dt = R_0 \tag{11}$$

The extraction rate defined in equation 10 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 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 τ, the operator's optimal extraction rate is:

$$q_t^* = \frac{p_t\left(1-\tau\right)}{2c} - \frac{e^{-r(T(\mathbf{p})-t)}\left(\left(1-\tau\right)p_T - 2\sqrt{fc}\right)}{2c} \tag{12}$$

The permanent excise tax reduces extraction in all periods, tilting the whole extraction path

downward. Because the tax reduces revenues in all periods, including the final period of extraction when the well reaches its economic limit, 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.

This does not necessarily mean that the permanent excise tax reduces the life of a well. On one hand, lower extraction rates due to the tax will lead to a more than proportionate increase the amount of time necessary to pump the same reserves pumped in the no-tax case; for a given level of aggregate extraction, a slower extraction rate extends the life of the well.[9] On the other hand, the tax could result in the well shutting down with reserves remaining in the well; the operator will extract less oil in total, which for a given extraction path reduces the life of the well. Whether this combination of forces leads to a net increase or decrease in the life of the well will depend on how close the well is to its economic limit when the permanent tax is levied. Wells near the end of their original economic life are more likely to experience a net reduction in well life due to the permanent tax since the increase in abandoned reserves is a larger fraction of total oil remaining in the well when the tax is levied. Wells far from the end of their economic life could actually experience an increase in well life since the decrease in extraction rates may extend the life of the well more than the new shutdown condition shortens it.

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 time t_1

[9] For expositional clarity, assume that price is constant so that $p_t = p$ and that fixed costs are absent, $f = 0$. Then the exhaustibility constraint is:
$\int_0^T \left[\frac{(1-\tau)p}{2c} - \frac{(1-\tau)pe^{-r(T(\mathbf{p})-t)}}{2c}\right] dt = \frac{(1-\tau)}{2c}\left(pT - \frac{p}{r} - \frac{pe^{-rT}}{r}\right) \leq R_0$
so any change in τ must be offset by a more than proportional change in T. The increase must be more than proportional because the extraction rate declines over time; the additional reserves resulting from lower extraction rates are pumped when the extraction rate is low. At time T^0, the original life of the well, now $(1-\tau)$ additional reserves remain; these reserves will take longer than $(1-\tau)T^0$ to pump since the extraction rate at time T^0 is less than the average extraction rate up until T^0.

unchanged. To simplify the analysis, but without loss of generality, price is assumed to be constant between time 0 and t_1 and between t_1 and the end of the well's life. The price between time 0 and t_1 is denoted by $p_1 = (1-\tau)\, p_1^W$, where p_1^W is the pre-tax world price before t_1, and the price after t_1 is denoted by $p_2 = p_2^W$, where p_2^W is the pre-tax world price after time t_1.

For wells with pre-tax economic lives that extend beyond time t_1, while the tax is in place between 0 and t_1 the operator's optimal extraction rate is:

$$q_t^* = \frac{p_1}{2c} - \frac{e^{-r(T(p_1,p_2)-t)}\left(p_2 - 2\sqrt{fc}\right)}{2c} \tag{13}$$

and after t_1 the optimal extraction rate is:

$$q_t^* = \frac{p_2}{2c} - \frac{e^{-r(T(p_1,p_2)-t)}\left(p_2 - 2\sqrt{fc}\right)}{2c} \tag{14}$$

The economic life of the well, $T(p_1, p_2)$, is a function of both prices: a higher tax rate in the first period will reduce extraction and lengthen the life of the well, a higher pre-tax price in either period will increase extraction rates in that period and shorten the life of the well.

An increase in the tax rate reduces extraction in the first period. 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:

$$\frac{dq_t^*}{dp_1} \geq \frac{1}{2c} - \frac{e^{-r(T(p_1,p_2)-t)}}{1+e^{-r(T(p_1,p_2)-t)}}\frac{rt_1}{2c} \tag{15}$$

again, where $p_1 = (1-\tau)\, p_1^W$, meaning that higher tax rates lead to lower extraction rates. The impact of a change in the tax rate on the contemporaneous extraction rate has two components: the direct impact from the first term of equation 13 and the indirect impact from the effect the change in tax rate has on the economic life of the well. The first term of equation 15 describes the direct impact of the change in price on extraction: a higher after-tax price accelerates extraction. The second term captures the mitigating impact of

the exhaustibility constraint: higher prices before t_1 reduce the life of the well, increasing the opportunity cost of extraction since the last barrel is pumped sooner, which reduces the effect of discounting. The economic life of the well, $T(p_1, p_2)$, which is shortened by a higher after-tax price in the first period, is implicitly defined by the exhaustibility constraint:

$$\begin{aligned} \int_0^{t_1} \frac{p_1}{2c} dt + \int_{t_1}^{T} \frac{p_2}{2c} dt - \int_0^{T} \frac{p_2 e^{-r(T-t)}}{2c} dt &\leq R_0 \\ \frac{p_1 t_1 + p_2 (T - t_1)}{2c} - \frac{p_2 \left(1 - e^{-rT}\right)}{2cr} &\leq R_0 \end{aligned} \tag{16}$$

Taking the total derivative of equation 16 reveals[10]

$$\frac{dT}{dp_1} \leq \frac{-t_1}{p_2} \frac{1}{1 - e^{-rT}} \tag{17}$$

meaning that a higher tax rate, which reduces p_1, extends the life of the well by reducing extraction rates between time 0 and time t_1. Higher temporary excise taxes lead the operator to re-time production, shifting extraction from the tax period to the future when the tax has expired. This forward tilting extends the life of the well because the additional reserves that result from slower initial extraction will be pumped such that extraction costs are minimized, which means extending the life of the well.

For long-lived wells, where $T(p_1, p_2)$ is large, the impact of the second term of equation 15 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 15 is approximately:

$$\frac{dq_t^*}{dp_1} \geq \frac{1}{2c} \tag{18}$$

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.

[10] The total derivative of equation 16 is $\frac{t_1}{2c} + \frac{p_2}{2c}\frac{dT}{dp_1} - \frac{p_2 e^{-rT}(-r)}{2cr}\frac{dT}{dp_1} \leq 0$

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; specifically the temporary tax could induce earlier shut-in of wells with little remaining productive life. 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.

2.3 Summary

The extraction rate is an increasing function of the price today and a decreasing function of the price at the end of the well's life; the higher the ultimate price of oil, the greater the opportunity cost of extracting a unit today that would otherwise remain in the well until its last period of production. Excise taxes affect both the current price and the opportunity cost of extraction. Temporary taxes mainly affect the current price for long-lived wells, thus creating strong incentives for operators to re-time production, shifting extraction from the tax period to the post-tax period. This shifting means that the short-run output gap induced by a temporary excise tax on the extraction of an exhaustible resource overstates the welfare cost of such taxes; reserves not extracted while the tax is in place will be extracted later, albeit less profitably because of discounting and higher costs due to sub-optimal extraction. This retiming also reduces the tax revenue raised. 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. The estimated cost parameter should be used to calculate total surplus from production, taking the dynamics of extraction into account.

3 Institutional Background

To identify to the supply elasticity and the cost parameter c, I examine domestic producer decisions during a period characterized 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. Subsection 3.1 describes the California oil industry and explains the exogeneity of world price to the production decisions of U.S. producers and its implications for domestic producer prices. Subsection 3.2 describes the decontrol of domestic oil prices and the levying of the 1980 Windfall Profit Tax (WPT).[11] I use the over-time and across-well variation in after-tax price generated by decontrol and the WPT to identify the after-tax price elasticity and the cost parameter c.

3.1 The California Oil Industry: Production and Producer Price

The United States is the third largest oil producer[12], behind only Saudi Arabia and Russia; California is the third largest oil producing state in the U.S. Onshore oil producers in California account for roughly one percent of total world production.[13] The oil produced in California is of lower quality than more prominent benchmark crudes such as West Texas Intermediate (WTI), the price of which is used in future and forward markets. 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.[14] California oil was more than 60 percent heavy or very heavy crude during the 1977-1985 period. Heavy

[11] The name Windfall Profit Tax (WPT) is a misnomer. The tax was not a profit tax, but an excise tax applied to the selling price of a barrel of oil regardless of its production cost.

[12] The U.S. was the third largest producer in the 1970s and 1980s as well though U.S.S.R production totals were less accurately measured.

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

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

oil is generally more expensive to extract as its weight increases pumping costs. 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. In California, heavy oil wells are also less productive than wells that produce lighter oil.[15]

U.S. producer prices are not sensitive to the production decisions of individual operators. Domestic pre-tax prices are set by the global oil market. Aggregate U.S. oil production comprised roughly 15 percent of total world production while price controls and windfall profit taxes were in place, a substantial but decidedly minority share. Unlike most other oil producing nations, oil extraction in the U.S. is a competitive market where large international oil firms operate alongside many smaller independent producers. Though the large international companies that operate in the U.S. also operate abroad, their market share was dramatically undercut by the establishment of the Organization of Petroleum Exporting Countries (OPEC) in 1960. By the mid-1970s, OPEC nations accounted for roughly half of world production and coordinated their production decisions in an effort to influence price. Though the evidence on OPEC's effectiveness as a cartel is mixed,[16] if any group of producers had the market share and coordination necessary to affect prices, it was and remains nationalized producers rather than the competitive fringe that operates in the U.S.[17] 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

[15]Heavy oil is oil with an American Petroleum Institute (API) gravity less than 20; very heavy oil is oil with an API gravity less than 16. API gravity is an inverse function of specific gravity—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. These wells were, on average, less productive than wells that produced lighter crude as 52.9 percent of well-month observations produced very heavy oil and 12.3 percent of well-month observations produced heavy oil.

[16]Hamilton (2009) reviews recent production and quota discrepancies among OPEC nations and finds that OPEC members frequently cheat with respect to their quotas and there is little evidence of a clear enforcement mechanism. Also see Alhaji and Huettner (2000) for a review of 13 studies assessing the effectiveness of OPEC as a cartel.

[17]As the U.S., including California refiners, imports oil, within the range of transportation costs, domestic producers may have some pricing power. Given that transport costs comprise roughly 5 percent of oil prices, domestic producers have only a small scope of pricing power.

be price-takers.[18]

Refiners always had the option to purchase imported oil—which was exempt from both price controls and the WPT. During the price control era, a permit trading system allocated low-price domestic crude among refiners.[19] Refiners did not face shortages since imported oil was always available for purchase. Thus, refiners and perhaps consumers benefitted form price controls while domestic producers saw their prices reduced by the price ceiling. 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.[20]

3.2 The Decontrol of Oil Prices and the Introduction of the 1980 Windfall Profit Tax

In an effort to combat inflation, the Economic Stabilization Act of 1970 instituted a wide array of wage and price controls. Domestically produced crude oil and refined products were among the goods subject to price controls. While virtually all other price controls were eliminated, prices caps on domestically produced crude oil and refined products remained in place until 1980. The decontrol of oil prices began with the Energy Policy and Conservation Act of 1975, which authorized the president to rescind price controls at any point after May 1979, and the Energy Conservation and Policy Act of 1976, which decontrolled oil extracted from marginally productive wells called stripper wells. Decontrol was a reaction to the sudden increase in oil prices due to the 1973 Arab oil embargo. Rising prices and less stable foreign sources prompted concerns regarding U.S. oil independence and generated

[18] 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 et al. (1986).

[19] Since only domestic crude was subject to price controls, refiners who procured domestic crude earned rents. The federal government created a system of tradable permits to allocate low-priced domestic crude among refiners to "fairly" distribute the potential windfall. Permits were allocated according to historic crude sourcing.

[20] 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).

interest in increasing domestic oil production. The Carter administration actively used the authority, and 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.[21] 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 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.[22] An operator's WPT tax liability was equal to the product of the WPT tax rate and the difference between the selling price and the base price for each barrel of oil he sold. Oil in each tier was also assigned a different base price. Thus, for the operator of well i at time t, each barrel of oil sold at price P_{it} incurs a WPT liability of:

$$\text{WPT Tax}_{it} = \begin{cases} \tau_{it}^{W}\left(P_{it} - B_{it}\right) & \text{if } P_{it} > B_{it} \\ 0 & \text{otherwise} \end{cases}$$

where B_{it} is the real base price. 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

[21] 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."

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

t was:

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

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 the three tiers of oil follow.

Tier I Oil

Tier I oil was oil extracted from a non-stripper well that produced oil in 1978 which was not heavy; that is, its API gravity exceeded 16. Tier I oil had been subject to price controls through the end of 1979. Price controls on Tier I oil were phased out gradually. 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. At the end of January 1981, the phase-out of price controls was abruptly ended and Tier I oil was fully decontrolled, raising the weight on the world price from roughly 60 to 100 percent. During the first 10 months of the WPT the windfall profit tax was applied to a selling price that was in part a controlled price. 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

Tier III oil was composed of two types of oil, new oil from wells that did not produce oil in 1978 and heavy oil, which is 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, the ratio of the statutorily set average base price to average prices in December 1979. 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 above section details the substantial variation in after-tax price over time and across wells created by the decontrol of oil prices and the introduction of federal excise taxes. 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. Thus even field aggregation would not be fine enough to correctly assign even average prices accurately to oil production by field. 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 Sources and Description

The data used in this study cover all potentially active onshore oil wells in the state of California, beginning in 1977 and continuing through 2008. 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 currently or 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 level 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.

California is divided into six oil and gas districts. Figure 1 maps the districts and provides details on the geographic distribution of wells and production. Each month between 1977 and 1985, total California production ranged between 2.37 million barrels in February 1978 and 3.20 million barrels in August 1985. Roughly 16.1 percent of wells are shut-in on average;

there is some variation in shut-in rates, with the smallest share of shut-in wells, 14.5 percent, during October 1978 and the largest share, 17.5 percent, in December 1985. Each of the top five producing wells accounts for less than 0.5 percent of total production.

Some adjustments to the data were necessary. Of the more than 30 million well-month observations, approximately 0.1 percent were duplicate observations; these were dropped. 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. API gravity information is necessary to determine the after-tax price each producer faced when he made the decision either not to complete the well that period or to shut the well that period. 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. In order to correct for this data challenge, 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 field-by-field posted prices by month, API gravity for controlled and decontrolled oil during the price control period, and pre-tax selling prices after decontrol. 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.[23] Crude is globally traded and priced based on API gravity and location. Location provides

[23]During the price control era oil from the same well was classified as lower and upper-tier oil, with upper-tier oil receiving a higher price. Lower-tier oil corresponded to what regulators believed was the "expected" level of production based on the property's production history. Until the well produced its lower-tier quota, all oil it produced would sell at the lower-tier price. If the operator exceeded his lower-tier quota, then all additional oil produced would sell at the higher upper-tier price. The determination of whether a barrel of oil subject to price controls was upper- or lower-tier is beyond the capacity of the data. This analysis assigns all price-controlled wells the upper-tier selling price, as it is the more likely price for marginal production from a California well.

information on the sulfur content of the oil since sulfur content is largely constant across the wells in a field.[24] 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.[25] For refining purposes, oil of the same API gravity and sulfur content is viewed as perfectly 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. I drew the details of price control assignment and WPT tax treatment 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 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 production data are right skewed. The within-well production

[24] Transportation costs will also vary by location. 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.

[25] 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.

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 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 2 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:

$$q_{it} = \alpha + \beta\left(1 - \tau_{it}\right) p_{it} + X_{it}\gamma + u_i + \eta_{it} \tag{19}$$

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.[26] 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 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 19 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

[26]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.

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. Starting in January 1983, the Real Post Price drifts slightly downward but is largely flat; the After-Tax Price only further flattens this slight negative slope.

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 simply a downward shift of the After-Tax Price line; the magnitude of the shift is the level of the Well Mean line. Further purging the post-well fixed effect after-tax price residuals of time fixed effects amounts to subtracting the average price each period over all wells from the post-well fixed effect residuals. 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 resid-

ual 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 thus the oil it produces is classified as new oil. The After-Tax Price line jumps upward in June 1979 when new oil was decontrolled and again several months later as world price increased and posted prices reflected the change. 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 in time. 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—though the residuals remain above zero, reflecting the fact that this well was fully decontrolled. The residual remains positive even after the introduction of the WPT because it was tax-favored, meaning it received a higher after-tax price than the average California well. Declining posted prices starting in 1983 brought the

well's after-tax price in line with its average after-tax price, which resulted in a near zero two-way residual since nearly all wells experienced this convergence.

Price variation generated by temporary taxes is likely to be perceived as having a persistence that differs from that generated by movements in price. Different forces generate price- and policy-induced changes in after-tax price; that they would be viewed identically seems unlikely. If producers perceive price 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; in other words, the average after-tax price each period subtracted off. 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 Changes in After-Tax Price

Table 2 presents OLS estimates of

$$q_{it} = \beta_0 + \beta_1 \left(1 - \tau_t^{Corp}\right) \left(B_{igt} + \left(1 - \tau_t^{W}\right) \left(P_{gt} - B_{igt}\right)\right) + \beta_2 age_{it} + \chi_t + \delta_i + \epsilon_{it} \tag{20}$$

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 20. The estimated coefficient on the after-tax price, β_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.[27] Because well age is considered an important determinant of well productivity, column 3 adds a quadratic term in well age. The insignificant increase in the elasticity to 0.238, and the fact that the precision of the tax-price coefficient estimate is unchanged, suggests 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. API gravity fixed effects would undo the tax rate variation based on oil heaviness, so slightly coarser controls are employed. Column 4 reports a specification like that of column 1 but includes 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 Elk Hills field. The private firm extracting the oil made production decisions, but received less than the full posted price less taxes for each barrel it produced. Furthermore, because 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

[27] Adding well fixed-effects only, retaining the full variation in after-tax price, yields a point estimate of 2.617 (0.500), which translates into a much smaller elasticity, 0.071.

would. Thus, the production response of these NPR wells to changes in after-tax price might be smaller than the response for privately owned wells.[28] Column 5 presents estimates of a model identical to that of column 1, but drops the Elk Hills 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 2. The supply elasticity of the NPR wells, 0.173 (0.097), is roughly 25 percent smaller than the overall elasticity, but statistically indistinguishable from the overall or non-NPR elasticities. Interestingly, dropping these wells reduces the standard error of the after-tax price coefficient estimate by 30 percent.

6.1 High and Low Marginal Cost Wells

Equation 15 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 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.

[28] The NPR field was not tapped until 1976. In reaction to the 1973 Arab oil embargo the federal government opened the Elk Hills field to drilling in 1976. From 1976 until 1998 the federal government leased access to the field and a private firm extracted oil from the reserves. The oil was sold to private refiners at the market price with the proceeds divided between the extracting firm and the federal government; although the private firm determined production levels. Oil from the NPR was subject to both price controls and the WPT, but the price per barrel received by the private extracting firm was less than the posted price minus taxes.

Table 3 presents estimates of equation 20 separately for flowing and pumped wells. 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. Column 1 reports the baseline specification, which corresponds to column 1 of Table 2. Column 2 reports elasticity estimates for pumped wells, evaluated at mean sample price and production quantities. 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, however, rules out supply responses larger than 0.072. All elasticities are evaluated at average price and quantity, separately for pumped and flowing wells.

7 Well Closure Decisions

Wells that have high fixed costs are more likely to incur losses once the tax is put into place. 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 the tax was introduced; 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."

Table 4 reports conditional logit and OLS estimates of

$$S_{it} = \beta_0 + \beta_1 \left(1 - \tau_t^{Corp}\right) \left(B_{igt} + \left(1 - \tau_t^{W}\right) \left(P_{gt} - B_{igt}\right)\right) + \beta_2 age_{it} + \chi_t + \delta_i + \epsilon_{it} \qquad (21)$$

where S_{it} is a dummy variable equal to one if the well is shut-in and β_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.[29] The regressions reported in Table 4 are similar to the regressions of Table 2. Columns 1 through 4 report estimates of equation 21 from conditional logit models. As the predicted values of conditional logit models must lie between one and zero, the model excludes wells that experience no variation in shut-in status.[30] 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 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 of a 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

[29]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.

[30]For wells that are always shut-in or always open to have predicted values between one and zero, implies unbounded well fixed effect coefficients. The conditional logit model thus excludes these observations.

gravity decile increases the semi-elasticity by almost 25 percent—controlling for changes in the gravity of oil pumped from a well increases the magnitude of the semi-elasticity estimate to -0.117. Column 4 excludes wells from the Elk Hills 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. In fact the after-tax price semi-elasticity of shut-in among Elk Hills wells is only -0.0002 (0.0002). The difference between the results from column 4 and column 1, however, is statistically insignificant.

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; 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 more than 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.

8 Reconciliation with Estimates of the Previous Literature

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.[31] In other words 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.[32]

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. As explained in Subsection 3.2, government policies created large deviations between after-tax price and world price that differed by well. These deviations

[31] 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).

[32] Griffin (1985) is vague as to the particular problems price controls cause for his estimation strategy. Presumably, he means that the average price series from the MER that he uses somehow overstates prices during the price control era, creating an artificial negative relationship between price and production.

are not reflected in this pre-tax 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 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. 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).[33] Column 1 reports the results of my baseline specification, which corresponds to column 1 of Table 2. 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. The supply response of interest is the supply response to after-tax price movements with a persistence similar to that of proposed policy. As proposals have

[33]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.

largely described temporary taxes, the temporary price changes induced by government policy isolated here are more appropriate than movements in world price. Third, 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 measure of its after-tax price. Well-level data also allow me to control for underlying heterogeneity in well productivity over time and across wells. Table 7 details the advantage of the micro-data. All of the regression results reported in Table 7 use the well-specific after-tax price as the key explanatory variables. The baseline estimate, corresponding to the specification reported in column 1 of Table 2, 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 introduction of 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 imposed 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.[34] 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. Interestingly, the sign of the time trend coefficient is negative in these specifications, unlike those in columns 3 and 4, suggesting that these more similar non-heavy, non-stripper wells slowed their production over time, likely due to depletion, while other factors spared heavy and stripper wells from the same declining trend.

9 Illustration of Lost Producer Surplus Calculation

The elasticity estimates discussed in Section 6 suggest that operators react to temporary excise taxes by reducing production; according to the preferred 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 model described in Section 2 explains that a temporary tax has both a direct and an indirect impact: the direct impact is the decrease in production while the tax is in effect; the indirect effect is the change in the economic life of the well.[35]

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

[35] Alternative cost functions—namely, ones where the cost of extraction is strongly impacted by the amount of reserves remaining in the well—may not yield as long an extension in the life of the well. If the cost of extraction in the post-tax period is substantially reduced by the larger reserves resulting from slower extraction while the tax was in place, then the operator will pump more in the post-tax period. This increase in the pumping rate may lead to a smaller increase in the life of the well.

Because production here is the extraction of an exhaustible reserve, reducing production while the tax is in place may extend the life of the well.

The simple model described in Section 2 and the estimates from Section 6 can be combined to illustrate how the welfare cost of a temporary tax on exhaustible resources can be calculated. 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 15 can be ignored. The second assumption is strengthened 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. In addition, the model assumes that the operator knows the price path with certainty. The importance of this assumption hinges on whether the general form of the extraction rules of equations 13 and 14 generalize to models that add uncertainty in prices. With these assumptions in mind, the elasticity estimates from Section 6 can shed light on the welfare cost of temporary taxes like the WPT.

As Section 3 explains, excise taxes that apply only to domestic producers cannot be passed on to refiners or consumers because imported oil was exempted from the WPT. No change in consumer surplus results from such a tax. Because there is very little shut-in in response to changes in the after-tax price, the change in producer surplus is nearly equal to the change in producer profits; the only deviations arise from the small number of wells that shut-in and thus save their fixed costs. 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.

For clarity, the pre-tax price of oil is assumed to be constant, so that $p_1 = (1 - \tau)\, p$ and $p_2 = p$. The change in the life of the well for a small change in the tax rate, according to equation 17, is:

$$dT \leq \frac{t_1 \tau}{1 + e^{-rT^0}}$$

where τ is the excise tax rate, t_1 is the duration of the tax starting at time 0, r is the interest rate, and T^0 is the original economic life of the well.[36] 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. Once the tax has been introduced, the operator reduces his extraction rate before t_1, extending the life of his well by dT. Producer surplus 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. The total change in producer surplus due to the introduction of the temporary tax will be:

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

where q_t is the extraction rate at time t if the tax had never been levied, and $\hat{q}_t$ is the extraction rate at time t in light of the temporary tax. The time horizon is $T^1 = T^0 + dT$, the new economic life of the well extended by the reduction in extraction between time 0 and time t_1; the no-tax extraction rate q_t will be zero after time T^0. The tax rate, τ_t, varies over time, as it is initially positive while the tax is in place but is zero after time t_1 once the tax expires.

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, $c\left(q_t\right) = cq_t^2 + f$. For the baseline specification, column 2 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, $c = 0.0573$.

Figure 4 plots the optimal extraction path before and after the introduction of a 15 percent temporary tax that is in place for five years. The pre-tax price is \$25 over the whole life of the well. The well has an original life of 40 years, which increases to approximately

[36] This dT is an estimate of the increase in the life of the well that results from the introduction of a temporary tax. The estimate assumes that the well life in the denominator is the original well life. The actual change in well life would be calculated allowing this variable to increase along the interval over which we integrate with respect to dP.

40.74 years due to the tax. The area between the two curves to the left of their intersection is the amount of oil not extracted while the tax is in place, which would have been extracted had there been no tax. The area between the two curves to the right of their intersection represents the delayed extraction of this oil. The product of these areas and the after-tax price, discounted appropriately, is the change in revenue due to the forward tilting of the extraction path caused by the introduction of the tax.

Figure 5 plots the cost of extraction over the original extraction path and the extraction path once the tax has been introduced. Cost savings from extracting less oil during the five years while the tax is in place are offset by increased costs later as the "additional reserves" are extracted over the post-tax life of the well. The difference in total extraction costs—the difference between the area to the left of the intersection of the two curves and the area to the right, discounted appropriately—represents the added costs of suboptimal extraction due to the introduction of the tax.

Government revenue from the temporary excise tax:

$$GR = \int_0^{t_1} e^{-rt} \tau p \hat{q}_t dt$$

partially offsets the reduction in producer surplus. The total welfare cost of the tax is thus:

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

Table 8 reports the decrease in welfare due to a 15 percent excise tax as a fraction of original producer surplus, using the implied cost parameter, for different well lives, T, and tax durations, t_1. The interest rate and pre-tax price used are five percent and \$25, respectively. Table 9 reports the decrease in total surplus as a fraction of the government revenue raised from the tax. The ratios of Table 9 represent the average cost of a dollar of revenue in terms of lost total surplus. Producer surplus before and after the tax and government revenue in dollars can be found in the appendix tables. As we would expect, the estimates suggest that

a temporary 15 percent excise tax reduces producer surplus more for short-lived wells. The deadweight loss of the tax declines between a three- and five-year tax for a well with a 10-year life 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 well lives, even a five-year tax does not span enough of the well's life to see this pattern. Overall the numbers suggest that the welfare cost of temporary taxes like the WPT is considerably smaller than a static estimate would suggest. In fact, a five-year tax on a well with an original life of ten years reduces welfare by less than 3 percent of raised revenue. 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.

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 on 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.

10 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 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 time-varying factors, like world price, 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. To illustrate how the production elasticity estimates can be used to assess the efficiency effects of a temporary tax on exhaustible resources, I calculate the changes in production, extraction costs and time path, and revenue from a temporary 15 percent excise tax. The calculations suggest that the distortion in production decisions reduces the present value of producer surplus by between one and five percent of its original value, depending on the original life of the well and the duration of the temporary tax. Put differently, these 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.

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 results are particularly important for the analysis of policies such as oil import fees that seek to promote energy independence by raising producer prices of fossil fuels, since they suggest that one impact of such policies will be the acceleration of U.S. oil production from currently producing wells. My estimates do not provide any evidence on how such fees might affect exploration for new oil reserves or the decision to bring shut-in wells back into production.

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 (low API 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. Third, 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.

An important area for future work is how tax-induced distortions of the extraction path affect the total quantity of reserves extracted. If perturbing the extraction path relative to its no-tax level leads to less aggregate extraction over the life of the well, then even temporary taxes will lead to permanent reductions in production and corresponding welfare

losses. The effect of temporary taxes on total extraction is an open empirical question. One way in which such production loss can occur is if the well is shut-in earlier than it otherwise would be, but this is not the only channel. While the estimates from the California data presented here imply that shut-in decisions are relatively tax insensitive, shut-in elasticities could potentially be higher in other parts of the U.S. Shut-in elasticities are predicted to be higher where wells either have shorter lives or higher fixed and variable costs; although California wells have higher than average variable costs, fixed costs may be larger and wells shorter lived in other parts of the U.S. I hope to address these issues in future work.

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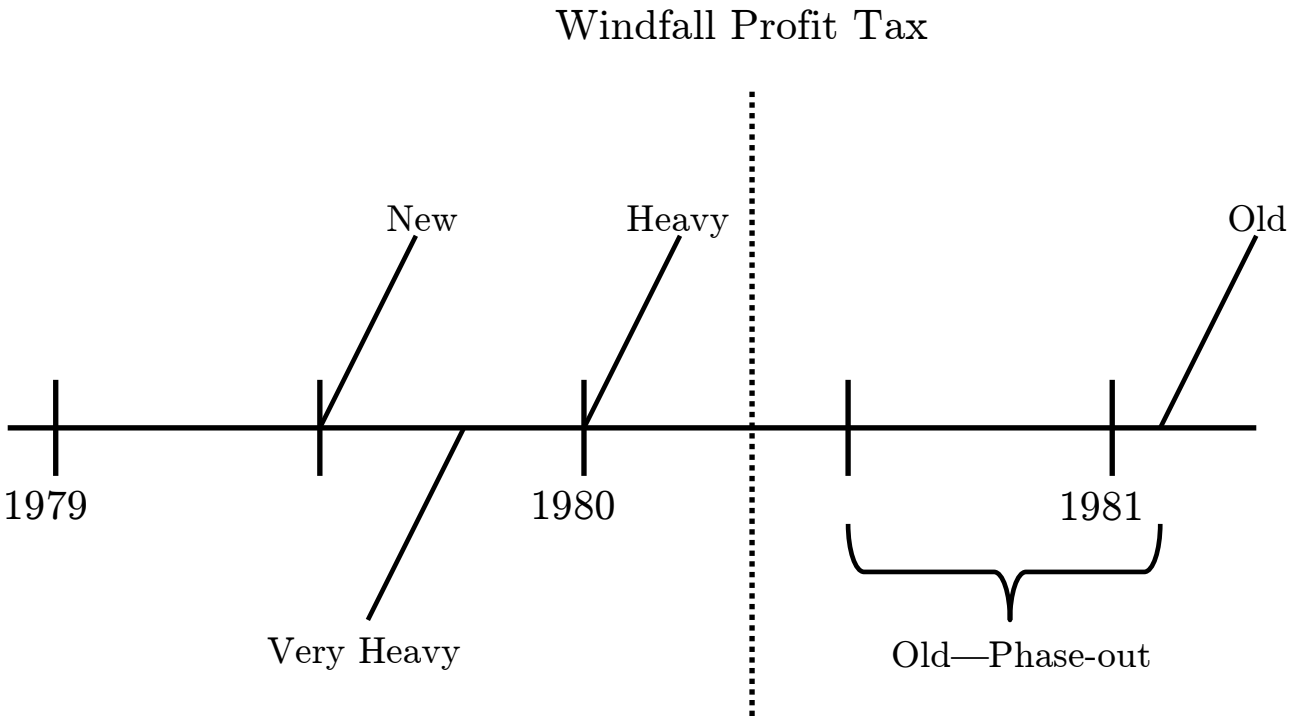
Figure 1: California Oil and Gas District Map

The Bakersfield district, accounts for roughly 61 percent of well-month observations and oil production; the next most productive district, Cypress, accounts for 18 percent of well-month observations but 24 percent of oil production. Ventura and Santa Maria, both of which are coastal, each account for approximately 6 percent of production, and the final district, Coalinga, pumps the remaining 3 percent of California oil production.

Source: California Department of Conservation, Division of Oil, Gas, and Geothermal Resources

Figure 2: 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.

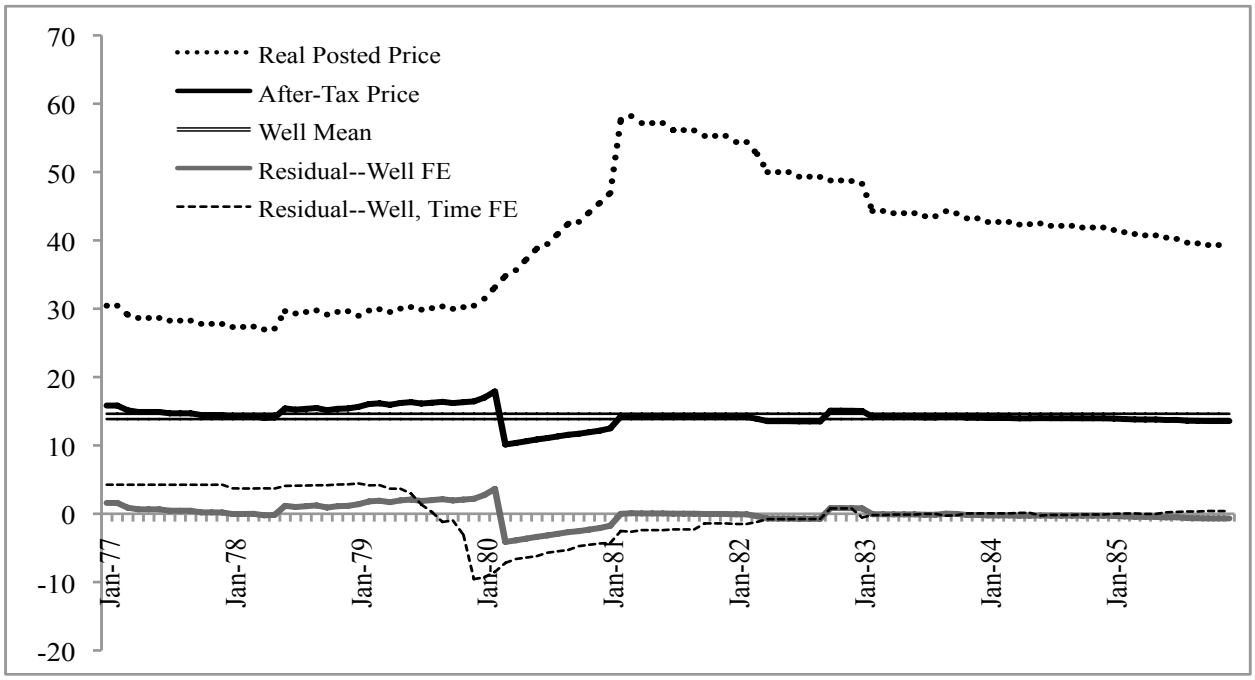
Old oil (oil extracted from wells that produced oil in 1978) was gradually decontrolled between January 1980 until January 28, 1981. During the phase-out period, old oil sold at a price that was equal to the weighted average of the world market price and the price control price ceiling, with the weight 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 3: 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%)

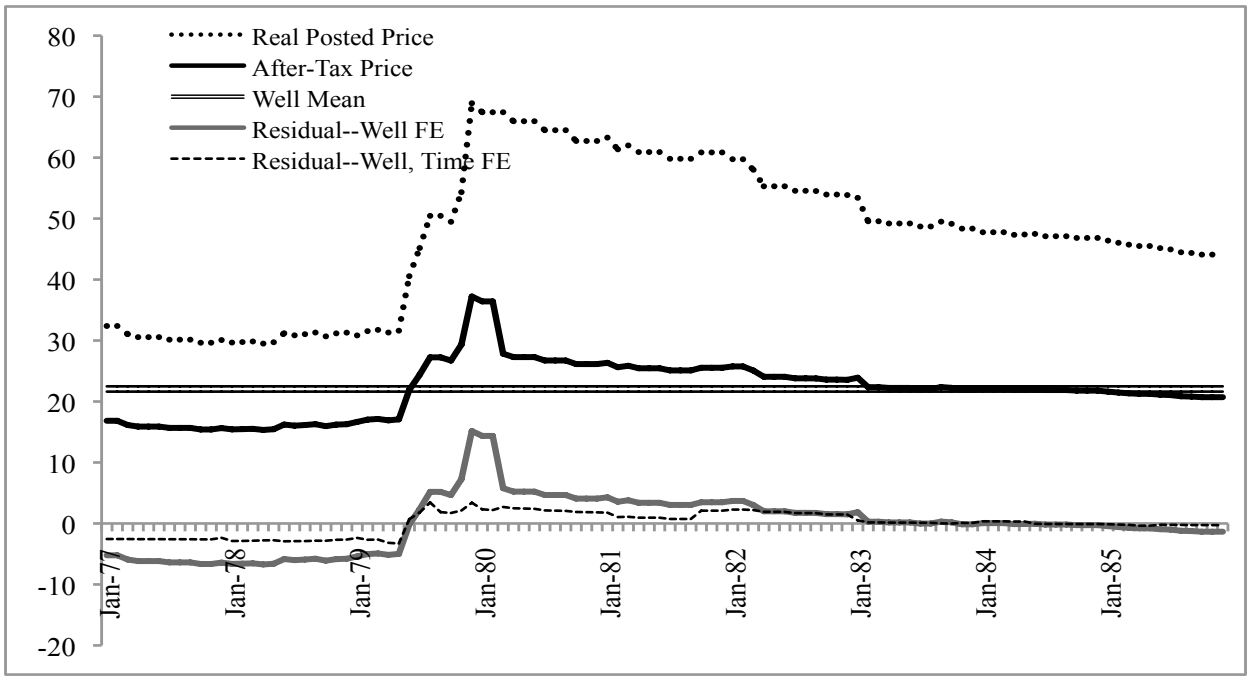


Figure 4: Optimal Extraction Path Before and After the Introduction of a 5-year 15% Excise Tax

Well with 40-year original life, 5 percent interest rate.

c = 0.0573

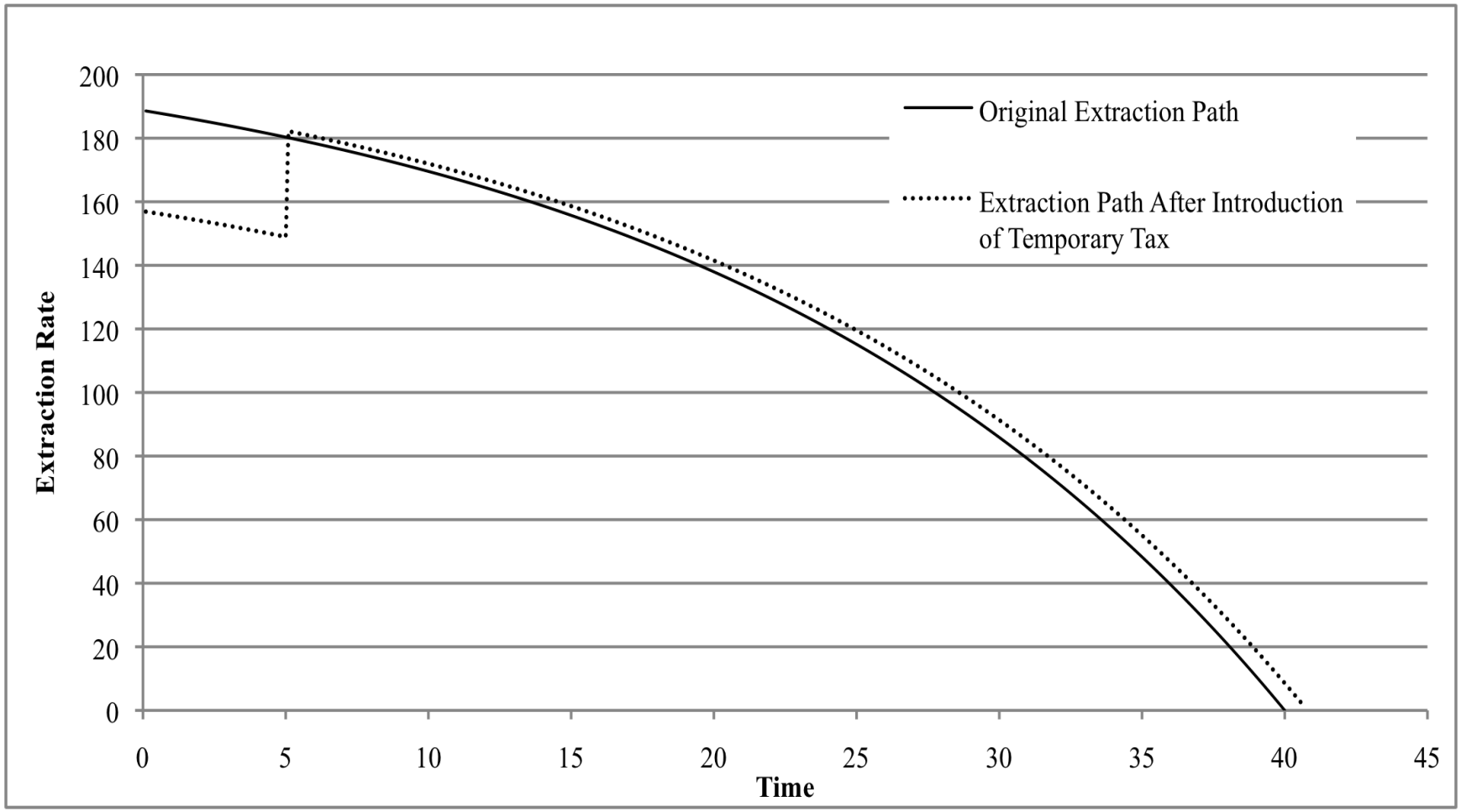


Figure 5: Cost of Optimal Extraction Before and After the Introduction of a 5-year 15 % Excise Tax

Well with 40-year original life, 5 percent interest rate.

c = 0.0573

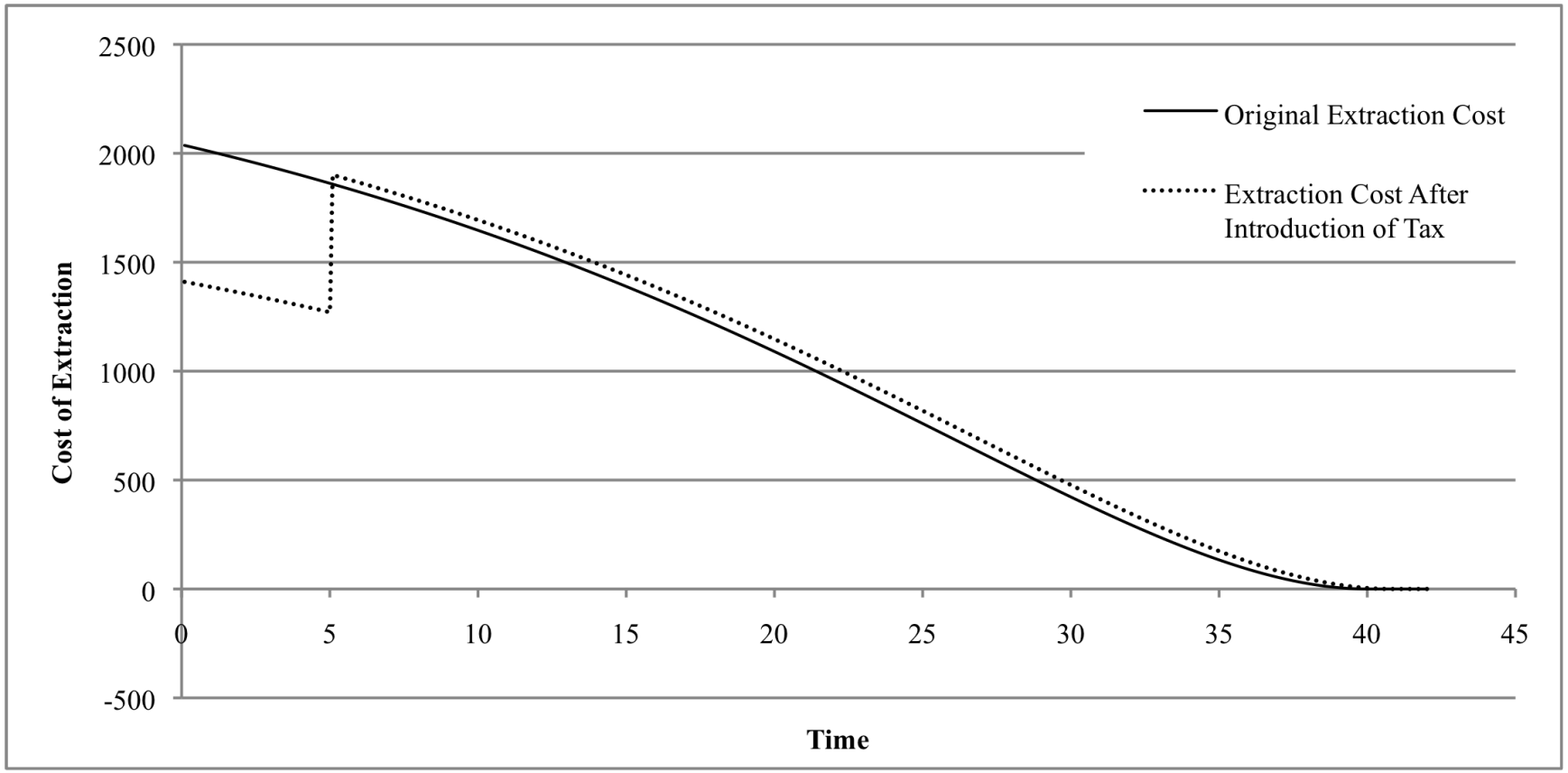


Table 1: Summary Statistics

	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: Well-Specific Output: Panel Data Estimates

	(1)	(2)	(3)	(4)	(5)
After-tax Price	8.730	8.741	7.659	9.598	-18.230
	(1.082)	(1.082)	(0.979)	(0.765)	(1.026)
Well Age	-1.269	-1.228	6.531	-1.258	-0.917
	(0.069)	(0.081)	(1.885)	(0.050)	(0.028)
Well Age Squared		-(0.0003)			
		(0.0002)			
Well Dummies	Y	Y	Y	Y	N
Time Dummies	Y	Y	Y	Y	N
API Gravity Decile Dummies	N	N	Y	N	N
API Gravity Decile Time Trends	N	N	Y	N	N
After Tax-price Elasticity	0.237	0.238	0.208	0.261	-0.496
	(0.029)	(0.029)	(0.027)	(0.021)	(0.028)
Number of Wells	75,342	75,342	75,342	73,548	75,342
Observations	6,517,140	6,517,140	6,517,140	6,350,820	6,517,140

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, β_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, β_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 Shut-in Var.	Cond. Logit Shut-in Var.	Cond. Logit Shut-in Var.	Cond. Logit No NPR	OLS Shut-in Var.	OLS 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	29,297	29,297	75,342
Observations	2,694,267	2,694,267	2,694,267	2,694,267	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, β_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. The semi-elasticity calculations for all specifications is the product of the marginal effect estimate and average after-tax price. Column 5 estimates an OLS model with well and time fixed effects using the full sample of wells. Column 6 estimates the fixed effect OLS model using the smaller sample of wells that experience variation in shut-in status. Columns 1-4 and 6 use a sample of wells that experience variation in shut-in status--a requirement of the conditional logit model.

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, β_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. 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 MER pre-tax price to average quantity for the sample of 4,681,973 producing oil wells. For columns 4 and 6 the in-sample averageMER pre-tax price and oil production are used to construct the elasticity.

For columns 1, 2, 3, and 5, 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, β_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.

For columns 1, 2, 3, and 5, heteroskedasticity robust standard errors are clustered at the individual well level.

Table 8: Percentage Decrease in Surplus Due to the Introduction of a 15% Temporary Excise Tax

	Duration of Temporary Tax (t_1)			
T^0	1	2	3	5
10	-0.006	-0.009	-0.009	-0.003
15	-0.004	-0.007	-0.009	-0.011
20	-0.003	-0.005	-0.007	-0.010
25	-0.002	-0.004	-0.006	-0.009
30	-0.002	-0.003	-0.005	-0.008
40	-0.001	-0.003	-0.004	-0.006

Note: This table reports the percentage change in total surplus, the loss in producer surplus less government revenue, for the operator of a single well whose cost function parameter $c = 0.0573$, which corresponds to the average elasticity response reported in column 2 of Table 2. The pre-tax price is assumed constant and equal to \$25. The interest rate is 5 percent. Producer surplus (PS) 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 $(PS^0\text{-}PS^1+GR)/PS^0$.

Table 9: 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 $(PS^0\text{-}PS^1+GR)/GR$.

Appendix: Producer Surplus Before and After the Introduction of a Temporary Excise Tax and Government Revenue Raised

Table A1: Producer Surplus Before the Introduction of a 15% Temporary Excise Tax

	Duration of Temporary Tax (t_1)			
T^0	1	2	3	5
10	\$8,447	\$8,447	\$8,447	\$8,447
15	15,190	15,190	15,190	15,190
20	21,801	21,801	21,801	21,801
25	27,776	27,776	27,776	27,776
30	32,929	32,929	32,929	32,929
40	40,792	40,792	40,792	40,792

Note: This table presents producer surplus for the operator of 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 (PS) is calculated using the following equation:

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

The economic life of the well, T^0, varies down the rows while the duration of the temporary tax, t_1, varies along the columns. Before the tax is in place, the "duration" of the tax is irrelevant, thus the surplus is equal across columns.

Table A2: Producer Surplus After the Introduction of a 15% Temporary Excise Tax

	Duration of Temporary Tax (t_1)			
T^0	1	2	3	5
10	\$8,207	\$8,008	\$7,847	\$7,631
15	14,837	14,521	14,237	13,764
20	21,363	20,959	20,589	19,938
25	27,271	26,801	26,363	25,580
30	32,372	31,851	31,362	30,477
40	40,164	39,571	39,012	37,987

Note: This table presents producer surplus for the operator of 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 (PS) is calculated using the following equation:

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

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

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.

Table A3: Government Revenue From the Introduction of a 15% Temporary Excise Tax

	Duration of Temporary Tax (t_1)			
T^0	1	2	3	5
10	\$192	\$363	\$519	\$789
15	297	569	819	1,258
20	380	734	1,062	1,646
25	446	863	1,253	1,956
30	497	965	1,403	2,201
40	569	1,106	1,613	2,544

Note: This table presents government revenue from temporary taxation of 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. Government revenue (GR) 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.