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Effectiveness of Severance Tax Incentives in the U.S. Oil Industry

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Abstract

This paper develops a dynamic empirical framework that can be used to test the effectiveness of state-level severance tax incentives in the U.S. oil industry. The framework embeds U.S. state-level panel data estimates into Pindyck's (1978) widely received theoretical model of exhaustible resource supply and can be applied to any of 20 states that produce significant quantities of oil. The model allows for interactions between taxes levied by different levels of government and for the first time addresses potential interstate differences in exploration costs, extraction costs, and reserve additions. In general, results show that severance tax incentives (in the form of tax rate reductions) substantially reduce state tax revenue collected, but yield moderate to little change in oil drilling and production activity. This outcome suggests that states should be wary of arguments asserting that large swings in oil field activity can be obtained from changes in severance tax rates.

Keywords: state taxation, nonrenewable resources

JEL Code: H71, Q32

1. Introduction

For roughly twenty years, major oil and gas producing states have granted severance tax exemptions, reductions, incentives, and credits to oil and gas producers for the purpose of stimulating exploration, field development, production, and job creation.[1] For example, to date 2000, Alaska, Kansas, and Louisiana have offered 13 such incentive programs, Texas has granted 12, Oklahoma 10, New Mexico 8, and Wyoming 8 (Interstate Oil and Gas Compact Commission, 2001). Incentive programs, generally, involve across the board cuts in nominal severance tax rates levied or discounts against existing severance tax liabilities for special situations faced by producers. The inherent tradeoff state governments must consider when offering incentives involves the potential loss of tax revenue for purported gains in exploration and production activity. A key question then arises: Are severance tax incentives effective in this regard? Surprisingly, very little empirical evidence exists regarding this question despite the heavy reliance on taxation of oil, gas, and/or coal production in many states to fund public goods.

This paper develops a dynamic empirical framework that can be used to test the effectiveness of state-level severance tax incentives in the U.S. oil industry. The framework embeds U.S. state-level panel data estimates into Pindyck's (1978) widely received theoretical model of exhaustible resource supply and can be applied to any of 20 states that produce significant quantities of oil. The model allows for interactions between taxes levied by different levels of government and for the first time addresses potential interstate differences in exploration costs, extraction costs, and reserve additions. As shown, costs, reserve additions, and tax structures vary considerably across states. Thus, this adapted model is arguably superior to and more comprehensive than previous efforts to develop general econometric and/or simulation models of taxation and natural resource exploration and production. Specifically, Deacon et al. (1990) and Moroney (1997) focus only on one state (California and Texas, respectively), and estimate econometric equations that may not be entirely consistent with a dynamic profit-maximizing framework. Pesaran (1990) estimates an econometric model of offshore oil production in the UK that can be better justified theoretically, but does not consider the role of taxes and estimates of the shadow price of oil in the ground are not always positive. Favero (1992) adds taxes to Pesaran's analysis, but again, estimates of the shadow price of oil in the ground are sometimes negative, suggesting that the model overstates the impact of taxation on profit. The Pindyck based simulation studies conducted by Yücel (1989) and Deacon (1993) examine effects of various types of tax changes on exploration and production but do not consider interactions between tax bases claimed by different levels of government, as well as possible interstate differences in exploration costs, extraction costs, and reserve additions. Also, these studies are aimed mainly at assessing the generality of theoretical results obtained in more limited settings rather than analyzing possible outcomes of changes in state tax policies.

Use of the modeling framework developed here is illustrated by simulating effects of reductions in *existing* state severance tax rates. Thus, results presented have the advantage of showing potential effects of specific state tax policy changes. Examining optimal tax regimes is beyond the scope of this analysis. In general, results show that severance tax rate cuts substantially reduce state tax revenue collected, but yield moderate to little change in oil drilling and production activity. This outcome suggests that states should be wary of arguments asserting that large swings in oil field activity can be obtained from changes in severance tax rates.

The remainder of the paper is divided into four sections. Section 2 presents the theoretical model used in the study. Section 3 presents empirical estimates of the model's parameters. Key estimates are obtained using panel data from the 20 most important oil-producing states over the period 1970–2000. Section 4 presents simulation results showing how oil exploration, reserves and production in Wyoming vary in response to severance tax reductions. Although the model developed can be applied to any of 20 states that produce significant quantities of oil, Wyoming is singled out because the estimates developed are likely to be at least broadly representative of what would be obtained for other states. Moreover, focusing on Wyoming highlights the state's heavy reliance on energy production taxes to fund public services. Implications and conclusions of this analysis are drawn out in Section 5.

2. Conceptual Framework and Model

The analysis presented in this paper extends Pindyck's (1978) model of nonrenewable resource development to incorporate key aspects of federal, state and local taxes facing the U.S. oil industry. Because the theoretical model is familiar, discussion later in this section is kept to a minimum. Perfectly competitive producers are assumed to maximize the discounted present value of future operating profits from the sale of resources. The firm's problem is to take known future output prices and taxes as given and then choose optimal time paths for exploration and production. This assumption parallels the basic tax competition models, reviewed by Wilson (1999), where governments commit to a tax regime and then perfectly competitive firms react treating the structure as exogenous.[2] Whereas the studies reviewed by Wilson model firms that are to some extent geographically mobile, firms extracting nonrenewable resources are tied to an immobile reserve base that represents the key component of their capital stock. In consequence, extractive firms view time, rather than space, as the most important dimension over which to substitute in response to changes in tax policy. Substitutions over time, of course, alter relative rates of exploration and production occurring at different locations. Yet, timing of activities is the most important aspect of the extractive firm's problem and information about location choice can be recovered as a by-product simply by comparing rates of development for particular reserves. A single firm is used to represent the industry, so the common pool problem and well spacing regulations are ignored (McDonald, 1994). For simplicity and because of data constraints discussed in the next section, exploration is defined to include resource development, although the two activities clearly are not the same (Adelman, 1990). The aim of exploration is to add to the reserve base, which in the model represents a form of immobile capital.

Institutional features of taxation facing oil producers are complex, however, incorporating these aspects into the model is not difficult conceptually and distinctly separates it from previous efforts mentioned in the introduction. Tax structures vary considerably among states and tax bases interact, particularly between the state and federal level. For example, among the eight states responsible for about 89% of 2000 U.S. oil production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming), all states except California levy severance taxes against the value of output. Severance taxes dominate other forms of local taxation in Alaska, Wyoming, and Louisiana. Most states do not levy property taxes on the value of reserves in the ground (Texas and California do). Most states treat royalty payments (computed as a percentage of gross value of production) for production on public land as deductible items in computing severance tax liabilities (Louisiana does not). Public land royalties are prominent in Alaska, New Mexico, and Wyoming due to the large shares of publicly owned land. Most states levy a corporate income tax that applies to oil operators (Wyoming and Texas do not). Also, states have granted innumerable exemptions and credits (which differ by state) against various tax liabilities for special situations that may be encountered by operators. Hence, effective rather than nominal rates are incorporated in the model developed below. Within states, counties apply their own mill levies to compute property taxes on above-ground and down-hole equipment at different rates. However, taxation of structures and equipment are usually less important than other sources of revenue and are not treated in the model below.

Regarding federal taxes, all incorporated producers file federal corporate income tax returns that allow deductions for various types of operating costs and for state and local tax payments. Independent producers (those without downstream refining or retail interests) are permitted to take a percentage depletion allowance, while major producers are allowed only cost depletion, which is significantly less generous. Both major and independent incorporated producers can expense intangible drilling costs incurred on their federal corporate income tax returns. The fact that some smaller producers are not incorporated and may therefore face alternative state and federal tax treatment is not treated here.

The firm's maximization problem now becomes

$$\max_{q,w} \quad \Omega = \int_{\circ}^{\infty} [qp - C(q, R) - D(w) - \gamma R]e^{-rt}\, dt \tag{1}$$

subject to

$$\dot{R} = \dot{x} - q \tag{2}$$

$$\dot{x} = f(w, x) \tag{3}$$

$$q \geq 0, \quad w \geq 0, \quad R \geq 0, \quad x \geq 0 \tag{4}$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil extracted measured in barrels, p denotes the exogenous market price per barrel net of all taxes, $C(q, R)$ denotes the total cost net of taxes of extracting the resource, which is assumed to depend on production (q) and reserve levels(R), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes the net of all tax constant effective property tax rate on reserves, r denotes the discount rate which represents the risk-free real rate of long-term borrowing, x denotes cumulative reserve additions (discoveries), $f(w, x)$ denotes the production function for gross reserve additions ($\dot{x}$) which is assumed to depend on current exploratory effort (w) and cumulative discoveries (x), and $\dot{R}$ denotes reserve additions net of production (q).[3] In this formulation, the net-of-tax price per barrel is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$,where α_p is a constant comprised of federal, state, and local effective tax rates such that $0 < \alpha_p < 1$. Correspondingly, $C(q, R) = \alpha_c C^*(q, R)$ and $D(w) = \alpha_D D^*(w)$, where α_c and α_D also are constants generated from effective tax rates and lie on the unit interval. A more complete discussion of the tax policy parameters follows below in Section 3.3.

The Hamiltonian for this problem is

$$\begin{aligned} H = {} & qpe^{-rt} - C(q, R)e^{-rt} - D(w)e^{-rt} - \gamma Re^{-rt} + \lambda_1[f(w, x) - q] \\ & + \lambda_2[f(w, x)]. \end{aligned} \tag{5}$$

Differentiating H with respect to R, q, x, and w yields the maximum principle conditions

$$\dot{\lambda}_1 = (C_R + \gamma)e^{-rt} \tag{6}$$

$$pe^{-rt} - C_q e^{-rt} - \lambda_1 = 0 \tag{7}$$

$$\dot{\lambda}_2 = -f_x(\lambda_1 + \lambda_2) \tag{8}$$

$$-D_w e^{-rt} + f_w(\lambda_1 + \lambda_2) = 0. \tag{9}$$

From equation (7), operators will produce if the discounted net-of-tax price exceeds discounted extraction costs. A severance tax decrease will increase the net-of-tax price which could affect the production decision. In equations (6)–(9), λ_1 is the discounted shadow price of the reserve state, λ_2 is the discounted shadow price of cumulative reserve additions, and letter subscripts represent partial derivatives. The shadow price of cumulative reserve additions, λ_2, is expected to be negative (and small relative to λ_1) for oil because current reserve discoveries will increase the amount of exploration needed in the future. From equations (8) and (9), the term $(\lambda_1 + \lambda_2)$ equals the discounted value of the marginal cost of adding another unit of reserves by exploration $[D_w/f_w]e^{-rt}$. Because $0 < \alpha_D < 1$, this net marginal cost is lower than in the pretax case.

The evolution of q is obtained by differentiating equation (7) with respect to time and setting the result equal to equation (6) to eliminate $\dot{\lambda}_1$. This yields

$$\dot{q} = \frac{-r(p - C_q) + \dot{p} - C_{qR}\dot{R} - (C_R + \gamma)}{C_{qq}}. \tag{10}$$

The optimal time path of w, can be determined using equation (7) and equation (9) to solve for λ_2, differentiating with respect to time to obtain an expression for $\dot{\lambda}_2$, equating the result to equation (8) and rearranging terms:[4]

$$\dot{w} = \frac{D_w[(f_{wx}/f_w) \cdot f - f_x + \mathrm{r}] + (C_R + \gamma)f_w}{[-D_w(f_{ww}/f_w)]} \tag{11}$$

Equation (11) shows that the trajectory of exploratory effort is determined by a tradeoff between the cost of finding new reserves and the extraction cost savings this new level of reserves yields. As specified in this model, a severance tax incentive (rate decrease) could increase incentives to explore and enhance reserves due to the subsequent increase in the net-of-tax price. This effect is discussed in more detail in Section 4. The numerator of equation (10) emphasizes the role reserves play in the optimal extraction path. If reserves rise, marginal extraction costs fall, thus increasing production. While general suppositions such as these can be drawn analytically, the complexity of the dynamic process just described may be best examined with simulation as developed below.

Boundary conditions can be established by first assuming that $D_w/f_w = 0$ when $w = 0$ (see Pindyck, 1978, pp. 846–847). In this situation, when production ceases at some terminal time T, exploration ceases at the same time because it is of no further value. Also, $\lambda_2(T) = 0$ as long as there are no terminal costs associated with cumulative discoveries. In consequence, from equation (9), $\lambda_1(T) = 0$ implies that operating profit on the last unit of reserves extracted is zero, $p = C_q$. An alternative terminal state centers on the case where $D_w/f_w = \Phi > 0$, when $w = 0$. In this situation, production will continue after exploratory effort ceases. Let $T_1 < T$ denote the time when $w = 0$. If exploratory effort is zero, $f_x = 0$, hence $\dot{\lambda}_2(T_1) = 0$ and $\lambda_2(T_1) = 0$. From (7) and (9), $p - C_q = \lambda_1(T_1)e^{rt} = \Phi = D_w/f_w$ which indicates that exploration will stop just as $p - C_q$ approaches marginal discovery cost, Φ. These two alternative terminal conditions are discussed in the next section as well as in connection with the simulations presented in Section 4.

3. Estimation

As shown in equations (10) and (11), the evolutions of w and q are nonlinear functions of both the levels of these variables and the previously defined tax parameters. Estimating these equations directly poses certain econometric issues (see Pesaran, 1990) and it is unclear how information from the transversality conditions would be incorporated. In consequence, rather than attempt to obtain econometric estimates of these two equations directly, equations for exploration costs (D^*), production of reserve additions (f), and extraction costs (C^*) are estimated and then substituted into the model along with estimates of the tax policy parameters α_p, α_c, α_D, and γ (see Yücel, 1989; Deacon, 1993 for similar treatments). Effects of severance tax changes then are obtained by simulation. State-specific estimates of equations for D^* and f are treated together in Section 3.1 because they are used to compute the marginal cost of reserve additions (D^*_w/f_w) which is a crucial function of the model described above. The equation for C^* is treated in Section 3.2 and the tax parameters are derived in Section 3.3. Key interstate differences regarding all estimates are highlighted throughout the discussion below.

3.1. Marginal Cost of Reserve Additions

The before-tax marginal cost of reserve additions (D^*_w/f_w) is computed from estimates of equations for drilling costs and for the production of reserve additions. Drilling costs are modeled in equation (12) as proportional to drilling effort.

$$D^*(w) = \phi w e^u \tag{12}$$

This approach ensures that the objective function (see equation (1)) represents a perfectly competitive firm ($D_{ww} = 0$). In equation (12), ϕ is the parameter to be estimated, and the disturbance term e^u is lognormally distributed with mean of unity and variance σ_u^2. Data by state and over time on labor, capital, and other primary inputs to drilling are unavailable, so the annual number of wells drilled in a state is used as a measure of drilling effort (w). Data on footage drilled also could be used as a measure of w (see Deacon, 1993). However, in the data set applied (see below) the number of wells drilled is positively correlated with total footage drilled (Pearson correlation = .98). Also, total drilling cost is approximately proportional to both footage and the number of wells, so to some extent the two variables measure the same thing. As discussed in Section 2, cumulative reserve discovery (x) appears as an argument in the production function for new reserves (see equation (13) below). A proxy for x can be constructed from available data (American Petroleum Institute, 1971) on the total number of wells drilled by state since 1859 (when the first oil well was drilled in Pennsylvania), whereas corresponding data on total footage drilled since that date are not available. Thus, use of number of wells as a measure of drilling effort simplifies the simulations presented in Section 4 and eliminates the need for arbitrary assumptions about historical average depth per well.

The production function for reserve additions is specified as

$$f(w, x) = A w^{\rho} e^{-\beta \cdot x} e^{v} \tag{13}$$

where A, ρ, and β are parameters to be estimated and the multiplicative disturbance e^v is assumed lognormally distributed with mean of unity and variance σ_v^2. The functional form selected for f is similar to the equation describing the discovery process proposed by Uhler (1976) and later adopted and estimated by Pindyck (1978) and Pesaran (1990). The idea behind this equation is that the marginal product of exploration declines as reserve discoveries cumulate. As previously discussed, data on cumulative reserve discoveries of oil are unavailable, so the cumulative number of wells drilled by state was used as a proxy.

As in the drilling cost function, the annual number of wells drilled is used as a measure of w.

Drilling cost and reserve production functions are estimated using annual data from 20 U.S. states for which complete information on wells drilled, drilling costs, reserve additions, and cumulative drilling could be assembled for the period 1970–2000.[5] Regarding costs, operators report the total cost (both tangible and intangible) of each well completed (including dry holes) via the Joint Association Survey on Drilling Costs.[6] Oil reserve additions are comprised of extensions, new field discoveries and new reservoir discoveries in old fields as defined by the U.S. Department of Energy, Energy Information Administration (DOE/EIA). The 20 states included in the data set accounted for 98.5% of the total U.S. oil production over 1970–2000.

Data sources, definitions, and sample means of variables used in the analysis are presented in Table 1. All nominal costs are converted to year 2000 dollars using the GDP deflator. Equations (12) and (13) were estimated in natural logarithms. An instrument for the natural logarithm of *WELLS* was used in equation (13) because w is an endogenous variable in the model presented in Section 2 and a Durbin-Wu-Hausman test (see Davidson and MacKinnon, 1993, pp. 389–393) rejected the exogeneity of w at the 5% level. An instrument for w was obtained by predicting the natural logarithm of the number of wells drilled from the one-way fixed-effects regression reported in Table 2. Time-specific effects tested insignificant at conventional levels. *PRICE* and *CWELLS* were included as explanatory variables because they are exogenous variables in the model. *PRICE2*, *CWELLS2*, and *PRICE*CWELLS* were included to account for non-linearities expected in light of relationships in the model. All estimated coefficients are significantly different from zero at conventional levels. The marginal effect of *WELLS* with respect to *PRICE* increases at a decreasing rate. The Pearson correlation between the actual values of *LN(WELLS)* and the corresponding predicted values, *LN(PREDWELLS)*, is 0.96.

Estimates of the drilling cost equation (12) are obtained by regressing the natural log of drilling costs minus the natural log of wells on dummy variables for states and years. This two-way fixed effects approach is a simple way to control for heterogeneity across states and over time. Examples of state-specific effects include geologic conditions, geographic remoteness of on-shore oil and gas resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time varying factors common to all states may include technological advancement and macroeconomic cycles. For this equation, each state-specific effect for a given year, conveniently, becomes the state-specific estimate of ϕ.

Estimates of equation (13) are obtained in a one-way fixed effects framework that yields common estimates of the slope coefficients across states and corrects for first-order serial correlation.[7] The one-way fixed effects estimation with correction for serial correlation is used for four interrelated reasons. First, this approach is a simple way to control for, yet avoid enumerating, unique aspects of states that affect reserve additions, but do not change over time. Second, time-specific effects are not jointly significant at conventional levels, making estimation in a two-way fixed effects framework unnecessary. Third, the random-effects specification, in which state-specific effects are treated as error components, is rejected by a Hausman (1978) test at the 5% level of significance. Moreover, conditional estimates of

Table 1. Variable definitions, data sources, and sample means.

Variable	Definition	Source	Sample mean
TRCOST	Total drilling costs in millions of 2000 dollars, for oil wells by state and year.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	332
WELLS	Total oil wells drilled in a state by year.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	741
CWELLS	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute. *Petroleum Facts & Figures* (1971 ed.)	95492
TRCWELL	Total drilling cost per well drilled, by state and year, in millions of 2000 dollars.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	0.723
FTWELL	Total footage per well drilled, by state and year.	American Petroleum Institute. *Joint Association Survey on Drilling Costs*. Annual.	5666
PRICE	Average wellhead price of oil per barrel, by state and year, in 2000 dollars.	American Petroleum Institute. *Basic Petroleum Data Book*. Feb. and Aug. Annually.	24.56
ADDED RESERVES	Oil reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrels.	U.S. Energy Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*. Annual.	31.4
RESERVES	Proved reserves by state and year in millions of barrels.	American Petroleum Institute. *Basic Petroleum Data Book*. Feb. and Aug. Annually.	1320.5
PROD	Production by state and year in millions of barrels.	American Petroleum Institute. *Basic Petroleum Data Book*. Feb. and Aug. Annually.	126.4
PRICE2	Average real price squared.	–	757
CWELLS2	Cumulative total wells squared.	–	3.4E+10
PRICE CWELLS*	Interaction of real price and cumulative total wells.	–	2.4E+6

the effects on reserve additions obtained from fixed-effects are thought to be of greater interest than corresponding unconditional estimates obtained using random effects. Fourth, the null hypothesis of no serial correlation is rejected at the 5% level, hence, the equation was re-estimated with correction for first-order serial correlation.

Table 3 reports estimates of the drilling cost equation for 8 major producing states. The 2000 state-specific estimates of ϕ have been corrected for the fact that the equation was estimated in logarithmic form (see Greene, 1997, p. 279). As shown, R^2 is 0.93 with state- and time-specific effects jointly significant under the appropriate F-test. State-specific estimates of ϕ test different from each other, except for Texas and Oklahoma, at the 5% level. Results suggest that total drilling costs increase with w and that constant marginal drilling

Table 2. One-way fixed effects construction of instrument for *LN*(*WELLS*).

Explanatory variable	Coefficient (t-statistic)
PRICE	0.062 (6.58)
PRICE2	−0.32E-3 (−2.34)
CWELLS	−0.33E-4 (−6.76)
CWELLS2	0.22E-10 (5.46)
PRICE ∗ *CWELLS*	0.72E-8 (1.82)
Summary statistics	
NT	620
R^2	0.86
F(19,596)[a]	49.55
F(30,565)[b]	1.18
Hausman[c]	45.20

[a]Test statistic for joint significance of state-specific effects.
[b]Test statistic for joint significance of time-effects after removing state-specific effects.
[c]Statistic for testing consistency of corresponding random effects estimates.

costs (D_w^*) differ substantially across the 8 states shown. Estimates of the reserve addition equation are shown in Tables 4 and 5. The coefficient of *LN(PREDWELLS)* is 0.56 and this estimate is significantly different from one and zero at conventional levels. The value of R^2 is 0.63 and the state-specific effects are jointly significant under the appropriate F-test. Also, the negative coefficient of *CWELLS*, though insignificant at conventional levels, suggests that reserve additions decline with the passage of time as new reserves become more difficult to identify. Table 5 shows the corrected state-specific intercept terms (A) for 8 major producing states. Results suggest that the marginal product of drilling (f_w) decreases with wells drilled and this marginal product would vary between states even if the number of wells drilled were the same in each.

Estimates of the two equations combined suggest that marginal cost of reserve additions (D_w^*/f_w) increases with drilling activity. As w increases, the marginal cost of drilling is constant, but the marginal product of drilling in finding new reserves (f_w) falls. Table 6 shows how pre-tax values of D_w^*, f_w, and D_w^*/f_w differ by state for 8 of the major producing states, assuming that the 2000 level of wells are drilled in each. Estimates of drilling cost per well (D_w^*) range from \$132,907 in Kansas, where wells tend to be shallow, to \$3,881,600 in Alaska, where the drilling experience is very different as compared to the lower 48 states. Marginal reserve additions from drilling (f_w) range from 11,051 barrels per well

Table 3. Two-way fixed effects, instrumental variable estimates of the drilling cost function (Corrected 2000 estimates of ϕ for 8 major producing states[a]).

State	Corrected fixed effect (t-statistic)
Alaska	3.881 (16.25)
California	0.277 (15.28)
Kansas	0.133 (24.05)
Louisiana	1.323 (3.38)
New Mexico	0.493 (8.41)
Oklahoma	0.357 (12.26)
Texas	0.352 (12.44)
Wyoming	0.601 (6.04)
Summary statistics	
NT	620
R^2	0.93
F(49,570)[b]	149.5

[a]See Greene (1997, p. 279) for specific details on intercept bias adjustment. 2000 time-effect added.
[b]Test of joint significance of state- and time-specific effects.

in Kansas to 177,067 barrels per well in Alaska. Thus, while drilling a well in Alaska is markedly more expensive than in Kansas, Alaska experiences a greater payoff from these more costly exploration and development efforts. In fact, estimates of the marginal cost of reserve additions, D_w^*/f_w, reflect somewhat less variation across states than do estimates of either D_w^* or f_w, ranging from a low of \$11.24 per barrel in Louisiana to a high of \$21.92 in Alaska. Although relatively little variation in D_w^*/f_w would be expected when operators are familiar with costs and payoffs from drilling in alternative locations, values of the marginal cost of reserve additions are not expected to be equal across states. For example, aside from random factors introduced in estimation, variation in D_w^*/f_w between states could be due to differences in oil quality, transportation costs, as well as other factors that can cause wellhead prices of oil to differ across states

3.2. Extraction Costs

Direct operating (lifting) cost for oil by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual cost index studies published by the DOE/EIA for the period

Table 4. One-way fixed effects, instrumental variable estimates of the reserve additions function.

Explanatory variable	Coefficient (t-statistic)
LN(PREDWELLS)	0.56 (11.09)
CWELLS	−0.3E-5 (−1.26)
Summary statistics	
NT	620
R^2	0.63
F(19,579)[a]	22.2
F(30,568)[b]	1.12
RHO	0.394
Hausman[c]	15.1

[a]Statistic for testing joint significance of state-specific effects.
[b]Statistic for testing joint significance of time-specific effects after removing state effects.
[c]Statistic for testing consistency of corresponding random effects estimates.

Table 5. One-way fixed effects, instrumental variable estimates of the reserve additions function (Corrected estimates of A for 8 major producing states[a]).

State	Corrected fixed effect (t-statistic)
Alaska	1.57 (1.64)
California	0.78 (2.01)
Kansas	0.31 (1.17)
Louisiana	2.49 (1.82)
New Mexico	0.57 (1.68)
Oklahoma	0.62 (1.94)
Texas	0.52 (2.11)
Wyoming	0.78 (2.03)

[a]See Greene (1997, p. 279) for specific details on intercept bias adjustment.

Table 6. Pre-tax marginal drilling cost, marginal product of drilling, marginal cost of reserve additions for 8 major producing states[a].

State	D_w^* (in \$)	f_w (in bbls)	D_w^*/f_w
Alaska	3,881,600	177,067	21.92
California	277,119	14,717	18.83
Kansas	132,907	11,051	12.03
Louisiana	1,323,014	117,753	11.24
New Mexico	492,620	27,123	18.16
Oklahoma	356,754	23,477	15.20
Texas	351,654	24,219	14.52
Wyoming	600,911	39,238	15.31

[a]Evaluated at each state's actual 2000 wells drilled. State-specific cumulative wells total is set to actual 2000 values.

1970–2000. However, these data are of limited value for two reasons. First, cost estimates are not always disaggregated to the state level and cost estimates for other states may not be representative of all production. Second, through the mid-1980s, price controls on oil and/or gas distorted production incentives, making historical extraction costs difficult to compare with extraction costs in more recent years. As a compromise, following Deacon (1993), values of extraction cost parameters are calibrated for the following Cobb-Douglas function,

$$C(q, R) = \kappa q^{\varepsilon} R^{1-\varepsilon}, \tag{14}$$

where $\varepsilon = 1/\mu$, μ is the production share of non-reserve inputs, and κ is a constant that drives the production cost modeled to an average level of *lifting costs* representative of the 2000 DOA/EIA surveyed estimates described above. State-specific estimates for μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above (see Deacon, 1993 for specific calibration methods). Table 7

Table 7. Non-reserve production input share μ, and pre-tax marginal extraction cost for major producing states.

State	μ	C_q[a]
California	0.27	7.12
Kansas	0.17	4.99
Louisiana	0.21	9.11
New Mexico	0.31	6.87
Oklahoma	0.26	6.89
Texas	0.32	7.01
Wyoming	0.34	6.93

[a]Calculated at 2000 levels for production and reserves, in year 2000 dollars. The EIA does not provide data for Alaska.

shows the pre-tax marginal extraction costs (C_q^*) and the non-reserve input shares (μ) for 7 major producing states. The DOE/EIA does not estimate lifting costs for Alaska. As shown, real marginal extraction costs range from a low of \$4.99 per barrel in Kansas to a high of \$9.11 per barrel in Louisiana. The Cobb-Douglas form for extraction costs insures that these costs will rise without limit as reserves approach zero. This condition implies that a positive level of reserves will remain at any terminal time, denoted T_1. Likewise, the functional form invokes a strictly positive level of production given any positive level of reserves. Thus, simulations reported in Section 4 are based on the second of the two alternative boundary conditions discussed in Section 2. This condition implies that production continues after incentives for further exploration vanish and that the terminal date for maximizing discounted operating profits must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

3.3. Tax Policy Parameters

For most states in most years, γ and $\alpha_j(j = p, C, D)$ can be specified by noting whether reserves are subject to a property tax (see text equation (1)) and then evaluating the following equations:

$$\gamma = \{(1 - \tau_{us})(1 - \tau_s)\tau_R\} \tag{15}$$

$$\alpha_p = \{(1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\delta\} \tag{16}$$

$$\alpha_c = \{(1 - \tau_{us})(1 - \tau_s)\} \tag{17}$$

$$\alpha_D = \{(1 - \tau_{us})(1 - \tau_s)\eta\} \tag{18}$$

The derivation of equations (15)–(18) can be found in Appendix A. In (15)–(18), τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, τ_R denotes the property tax rate on reserves weighted by the per unit assessed value, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p denotes the production (severance) tax rate, δ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and η denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. The parameter η is made up of two components: (1) the percentage of current period drilling costs expensed and (2) the estimated present value of cost depletion deductions for the capitalized portion of current and past drilling expenditures. Producers are allowed to expense costs associated with drilling dry holes along with certain intangible costs (e.g., labor and fuel) for completed wells as they are incurred. All direct (tangible) expenditures for completed wells must be capitalized then depleted over the life of the producing well.

This formulation captures several aspects of the U.S. tax structure as it applies to the oil industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes on reserves, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities. (3) State corporate income taxes are deductible against federal corporate income tax liabilities. As noted in

Section 2, state tax treatment of the oil industry is not uniform and there are a number of situations in which these equations would have to be modified. Notice that this treatment of taxes in the model highlights the interaction between tax bases and is more detailed than the corresponding treatment given by Moroney (1997) and Deacon et al. (1990). Also, the entire tax structure is incorporated into the model, rather than simply analyzing one tax at a time as in Deacon (1993).

All tax parameters in equations (15)–(18) are effective rather than nominal rates. States grant numerous credits and exemptions against taxes levied, so nominal rates generally overstate amounts actually paid. State and local data required for these effective rate calculations are neither available from a central source nor compiled in a common format, so they were obtained directly from tax officials in each state. Royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production. Production tax rates are computed as total production tax collections divided by the gross value of production net of public land royalties. At the federal level, data from Statistics of Income (U.S. Department of Treasury, 1999–2000) for the oil and gas sector show that federal corporate taxes paid averaged about 11% of *net operating* income in 2000. The ratio of the federal effective to marginal rate was also applied to each state's top marginal corporate income tax rate to obtain an effective estimate. The current nominal percentage depletion rate is 15% and it applies to each state's percentage of non-integrated producers. Also, the expensed portion of current period drilling costs is approximately 42% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that the ratio of production to reserves is constant (see U.S. Department of Commerce, Bureau of the Census, 2000; Deacon, 1993). The ratio of production to reserves (q/R) varies across states but the industry expense share (42%) applies to all states.

4. Simulation Results

The model presented in Section 2 can be simulated for any of the 20 oil-producing states to obtain responses of exploration and production to reductions in severance taxes. The discussion below focuses mainly on severance tax rate reductions in just one state, Wyoming, for four reasons. First, this approach substantially reduces the amount of institutional detail that must be presented. Second, despite the large interstate differences in costs, reserve additions, and tax structures shown above, changes in severance taxes turn out to have quite similar comparative effects in each of the major oil producing states. Therefore, estimates for Wyoming are likely to be broadly representative of what would be obtained for other states. Third, simulation results reported are based on the assumption that severance tax reductions in one state do not affect the wellhead price of oil seen by operators in other states. This assumption is warranted in view of the fact that oil prices are determined in a world market. Also, as shown below, tax rate cuts considered appear to lead to comparatively small changes in output, so cross border effects are unlikely to be important in any case. Finally, taxation of oil extraction is a long-standing, contentious public policy issue in Wyoming partly because of heavy reliance on energy production taxes to fund public services.

Simulations for Wyoming were performed using the estimates of equations (12) and (13), the calibrated production cost parameters ($\varepsilon = 2.93, \kappa = 150$) of equation (14), and the tax parameters ($\alpha_p = 0.72, \alpha_c = 0.89, \alpha_D = 0.75, \gamma = 0$ as derived in Appendix A. As shown, severance tax changes will affect the price tax parameter, α_p. The discount rate, r, was set at 4% to reflect the risk-free real rate of long-term borrowing and the future price path was fixed at $25.00 per barrel each year reflecting the real sample mean for all 20 states. Other price trajectories (rising or falling) were simulated, but the alternative paths have little or no effect on the comparative results presented below. The initial value of reserves and cumulative wells drilled are fixed to year-end 2000 levels at 561 million barrels and 39,993 wells, respectively. To obtain numerical solutions for the time paths of drilling, production, and reserves, difference equation approximations are derived for the time rates of change in production and exploratory effort (equations (10) and (11) and for the state variable evolution equations (2) and (3)). For example, the evolution of reserves, equation (2), is approximated by the difference, $R_{t+1} - R_t = f_t - q_t$. The model is solved recursively by iterating over the initial values of the control variables, $q$and w, until transversality conditions are satisfied. Under these base case conditions, exploratory effort approaches zero after approximately 40 years, thus the terminal time (T_1) is set to 40 periods. The Solver algorithm in Microsoft Excel was used to generate numerical solutions.

Before the simulation results are discussed, a historical analysis of Wyoming's oil experience is warranted. Figure 1 depicts the actual time paths of real price, wells drilled, production, and reserves for Wyoming from 1970–2000. In this figure, the vertical axis shows wellhead price (dotted line) in year 2000 dollars × 10, wells drilled (dashed line) in

Figure 1. Wyoming oil 1970–2000.

total wells, production (solid line) in bbls $\times 10^5$, and reserves (bold line) in millions of barrels (MMbbls). In reviewing these data, several observations are noteworthy. Historical drilling appears sensitive to price. Oil wells drilled increased markedly during the high price period of the early 1980s. Extraction activity, however, appears to map the declining proved reserve level in the state. In fact, oil production continued to decline during the late 1970s and early 1980s even though real prices increased roughly 3 fold. As shown, the increased drilling effort of the early to mid 1980s failed to replenish the depleting oil reserves in the state.

As depicted in Figure 1, the low real prices for oil in the 1990's provided the oil industry incentive to lobby state legislatures for tax breaks intended to stimulate exploration and production. In 1999, both Wyoming and Oklahoma enacted oil producer recovery acts which lowered state level nominal severance taxes by approximately 25–35% on all oil production, provided that oil prices remain below a certain level.[8] Using this scenario as a back-drop, the comparative simulation below shows the results of a once-and-for-all reduction in Wyoming's effective severance tax on oil production by 2 percentage-points. Results presented have the advantage of showing how exploration and production might be expected to change over time in response to an *actual* constant policy change.

The solid lines in Figures 2–4 show the evolution of drilling, reserves, and production under the base case assumptions outlined above. Wells drilled fall steadily over time from

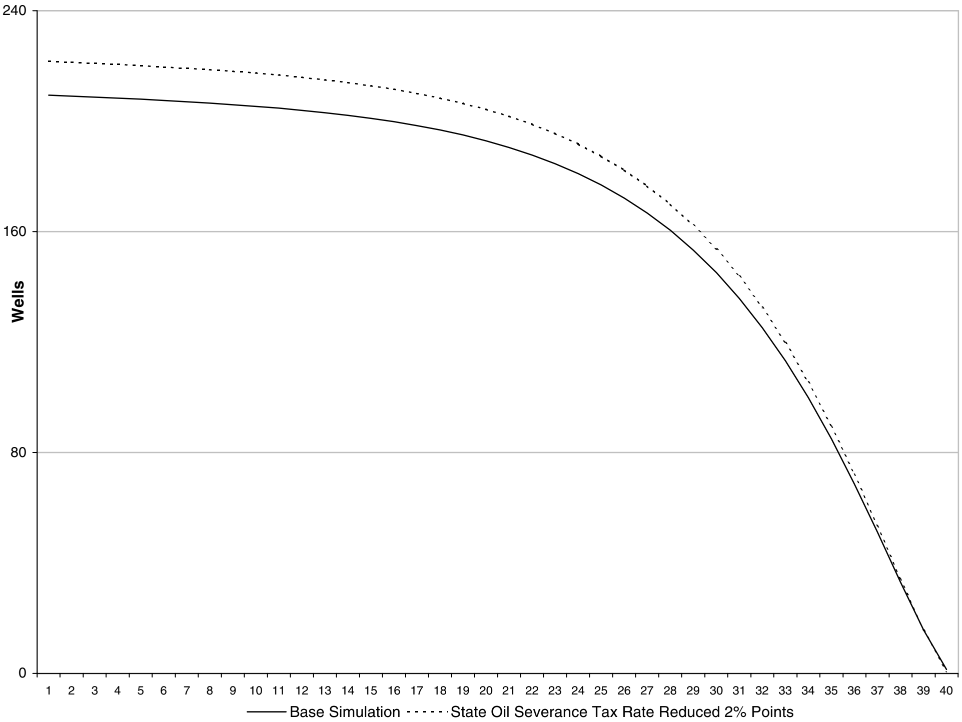

Figure 2. Wyoming oil (drilling).

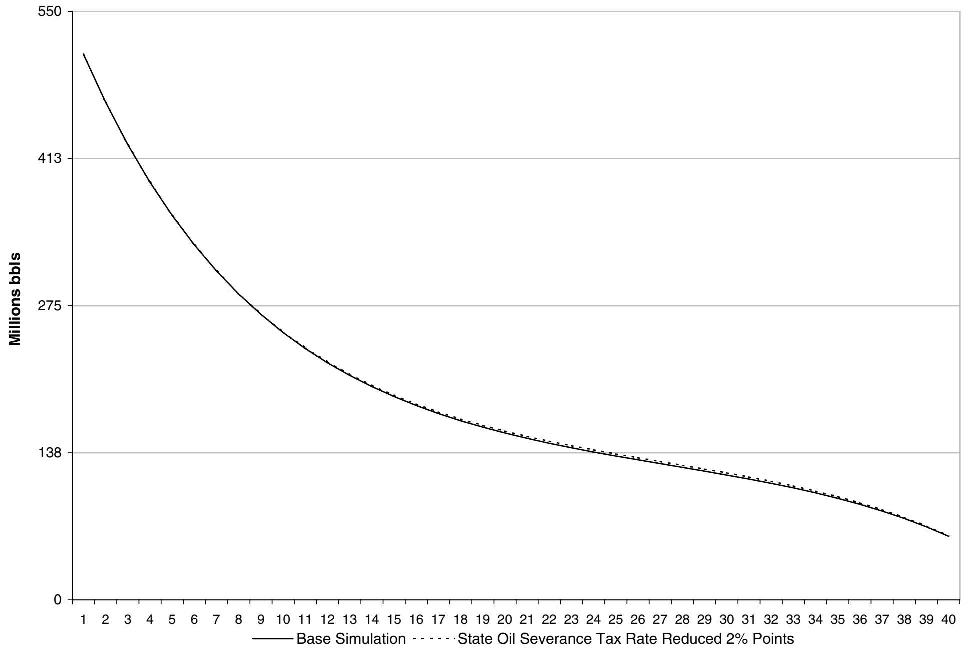

Figure 3. Wyoming oil (reserves).

209 in year 1 (2001) to 1 in year 40 (2040). Reserves also decline over this period from 510 MMbbls to 59 MMbbls with production declining from 59 MMbbls to 11 MMbbls. The dotted lines in these figures show the effects of a once-and-for-all reduction in the state oil severance tax by 2 percentage-points, which reduces the state effective rate from 5.8 to 3.8% and increases net-of-tax price by 40 cents (α_p increases by 0.016). As shown in Figure 2, the tax decrease increases drilling in the early years of the program when compared to the base simulation. Overall, drilling increases by 378 wells or 5.8% above the 40-year program base. With increased drilling in the early years, additional reserves are identified (15 million barrels more) and, as shown in Figure 3, proved reserves slightly rise in the out years.

Through the life of the program, the tax decrease results in increased production by about 14.9 million barrels, about 1.6% above the base solution. As Figure 4 depicts, this difference is roughly equal to the 15 million barrel increase in reserve additions that comes about because of the tax decrease. Also, the increase in output reflects a relatively low elasticity of production with respect to severance tax rate changes. Over the life of the program, this elasticity is approximately 0.05. Intuitively, while a decrease in the severance tax stimulates drilling activity, the additional drilling has a comparatively small effect on reserve levels. Given that over 63,000 wells (oil and gas) have been drilled in Wyoming to date 2000, prospects of a significant oil discovery are unlikely and the marginal product of drilling in finding new reserves is lower than in the past. As a consequence, reserve additions also respond inelastically to the severance tax decrease. Moreover, such small increases in

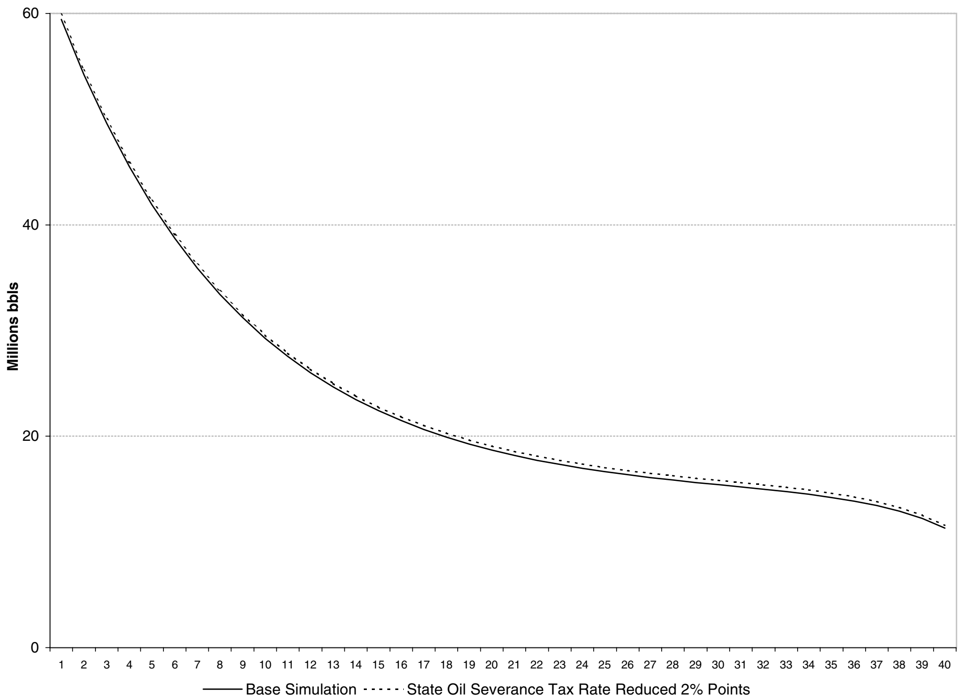

Figure 4. Wyoming oil (production).

net price (e.g., 40 cents per barrel) will unlikely affect production from existing wells and provides little incentive to reopen 'shut-in' wells.

The largest change associated with the 2 percentage-point reduction in state oil severance taxes is found in state production tax collections. Applying the discount rate of 4%, the tax change results in a decline in the present value of Wyoming *state* severance tax collections from $751 million to $498 million, a decline of over 33%. Alternatively stated, Wyoming would forego $669,312 in present value of severance tax revenue for each of the additional 378 wells drilled. Certainly, the incentive enhanced drilling effort may provide the state other forms of benefits (i.e., short-term rig employment and sales tax collections) but these additional benefits would have to be considerable in order to offset what appears to be an insurmountable loss of state tax revenue.

Because severance taxes are deductible in computing federal corporate income tax liabilities, tax payments to the federal government increase by $27 million (3.6% above the base case). Also, the 2 percentage-point severance tax decrease transfers state revenue to local governments because of the production stimulus. Discounted local production taxes increase by $12 million or 2% above the base case. The same can be said for discounted public land royalties which increase by 1.9% ($18 million) because of the increase in production. These results highlight the importance of the tax interactions described in Section 2 above.

The key result of this analysis is that oil reserve additions and production respond quite inelastically to reductions in severance tax rates. In the case at hand, a constant 2 percentage-point rate reduction increases overall simulated production by 1.6%—but decreases state severance tax revenue substantially in present value terms, by over 33%. This general outcome also applies to the other major oil producing states that levy a severance tax. In any case, oil-producing states should be wary of arguments promising large increases in oil exploration and production in response to cuts in severance tax rates.

5. Conclusions

This paper has adapted Pindyck's (1978) model of nonrenewable natural resource production to allow for an empirical test of the effectiveness of state oil severance tax incentives. Equations of the model are estimated econometrically from panel data on production, exploration and reserve additions for 20 states over the period 1970–00. The model is designed so that effects of changes in existing state severance tax rates on the evolution of exploration, reserves and production can be simulated into the mid-21st century. In general, results show that severance tax rate reductions result in a substantial loss of tax revenue, moderate increases in drilling, but little change in reserve additions and production. A key question regarding this general result is: Why does output of oil respond so grudgingly to changes in severance taxes? There appears to be four reasons why this is so. First, a reduction in severance taxes offers no *direct* stimulus for reserve exploration. A cut in the severance tax, as modeled, does nothing to directly stimulate reserve additions—operators get the future benefits of this tax incentive only if they drill *and only if they are successful.* In general, "upstream" incentives given at the beginning of the exploration-development-production process may provide a greater stimulus to production than "downstream" incentives given at the end of the process—e.g., cuts in severance taxes.

Second, operators do not see the full effect of state severance tax changes because of the many tax base and rate interactions at all levels. For example, severance taxes are deductible against federal corporate income tax liabilities. Therefore, when severance tax rates fall, federal corporate income tax liabilities rise and vice-versa. In fact, results herein suggest taxes should not be analyzed independently without reference to the entire tax structure applied by all levels of government; for example, a tax discount granted at one level may be partially offset by increased liabilities at another level. Therefore, operators do not receive the full value of tax reductions that may be granted by Wyoming and other states. Third, and in a related vein, a reduction in severance tax rates by 2 percentage-points has only a small impact on the net-of-tax price received by operators. The tax reduction simulated above increases the constant net-of-tax price by only 40 cents per barrel. This small increase cannot be expected to generate much in the way of *new* oil production.

Fourth, and most importantly, production of (as contrasted with exploration for) oil is driven mainly by reserves, not by prices, severance tax rates, or tax discounts. This is a basic fact of geology and is easily illustrated by reexamining Wyoming's own history of oil production. Since 1970, Wyoming oil reserves steadily declined from 1 billion barrels to 561 million barrels in 2000 (see Figure 1). In other words, despite much exploration over the past 31 years (over 12,300 wells drilled), production has drawn down reserves faster than new discoveries have added to them. This implies that for states like Texas, Oklahoma, and Wyoming the prospect of major exploratory success is not particularly promising (see Moroney, 1997 for a similar analysis of Texas). Moreover, during the past 31 years, oil production declined from 160 million barrels in 1970 to 61 million barrels in 2000. In fact, oil production continued to decline during the late 1970s and early 1980s even though real (year 2000 dollars) oil prices rose by a factor of more than 3, from about \$18/bbl. to more than \$55/bbl. Thus, even comparatively large price increases are not expected to call forth much additional output.

The general conclusion that severance tax changes appear to be unimportant may be problematic to public officials in oil producing states hoping to stimulate local economic activity by lowering such rates. The prospect of modest increases in exploration and production comes at a considerable cost, the loss of substantial state tax revenue that must be offset. Rather, state officials may have the incentive to raise severance tax rates risking little in the way of loss to future oil field activity.

Appendix A

This appendix derives the (generalized) constant tax parameters numbered (15)–(18) in the text. Restating the producer's problem (bracketed terms in text equation (1)) accounting for all tax effects yields

$$\begin{aligned} &qp^* - qp^*\tau_r - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R - \tau_s[qp^* - qp^*\tau_r \\ &\quad - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R] - \tau_{us}\{qp^* - qp^*\tau_r - qp^*(1-\tau_r)\tau_p \\ &\quad - qp^*(1-\tau_r)\delta - C^* - \eta D^* - \tau_R R - \tau_s[qp^* - qp^*\tau_r \\ &\quad - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R]\}. \end{aligned} \tag{A.1}$$

Collecting terms from (A.1) gives

$$(1-\tau_{us})(1-\tau_s)[qp^* - qp^*\tau_r - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R] + \tau_{us}qp^*(1-\tau_r)\delta \tag{A.2}$$

which reduces to

$$\begin{aligned} &qp^*\{(1-\tau_{us})(1-\tau_s)(1-\tau_r)(1-\tau_p) + \tau_{us}(1-\tau_r)\delta\} - C^*\{(1-\tau_{us})(1-\tau_s)\} \\ &\quad - \eta D^*\{(1-\tau_{us})(1-\tau_s)\} - \tau_R R\{(1-\tau_{us})(1-\tau_s)\}. \end{aligned} \tag{A.3}$$

For a single barrel of q and R, (A.3) becomes

$$\alpha_p p^* - \alpha_c C^* - \alpha_D D^* - \gamma. \tag{A.4}$$

where

$$\gamma = \{(1-\tau_{us})(1-\tau_s)\tau_R\} \tag{A.5}$$

$$\alpha_p = \{(1-\tau_{us})(1-\tau_s)(1-\tau_r)(1-\tau_p) + \tau_{us}(1-\tau_r)\delta\} \tag{A.6}$$

$$\alpha_c = \{(1-\tau_{us})(1-\tau_s)\} \tag{A.7}$$

$$\alpha_D = \{(1-\tau_{us})(1-\tau_s)\eta\} \tag{A.8}$$

equate to equations (15)–(18) in the text.

Wyoming Tax Parameters

In developing a base simulation solution, equations (A.5)–(A.8) can be simplified because Wyoming does not have a state corporate income tax ($\tau_s = 0$) and does not levy a property tax against reserves in the ground ($\tau_R = 0$). For Wyoming, royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production and averaged 9.1% for oil in 2000. This percentage is higher than for other oil producing states because of the comparatively large share of Wyoming's production on public lands. Production tax rates are computed as total production tax collections divided by the gross value of production net of public land royalties. In Wyoming, there are both local and state levies against this net value of production. Local ad valorum taxes are based on the prior year's production value. The sum of the two average effective rates in 2000 totaled approximately 12.3% (local 6.5% and state 5.8%). Also, the current nominal percentage depletion rate of 15% applied to about 52% of Wyoming oil producers in 2000, thus $\delta = 7.8\%$. Also, the expensed portion of current period drilling costs is approximately 42% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that the ratio of production to reserves is constant (see Deacon, 1993). Wyoming's mean value of q/R was approximately 11% for the sample period, therefore $\eta = 0.42 + (1 - 0.42) * (0.11/(0.04 + 0.11)) = 0.84$. The base tax policy parameters for Wyoming are $\alpha_p = 0.72$, $\alpha_c = 0.89$, $\alpha_D = 0.75$, $\gamma = 0$.

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Notes

1. Severance or production taxes are typically ad valorem taxes levied on the net production value (or volume) of a resource as it is extracted from the ground or at the final point of sale.
2. Making tax rates endogenous to the problem considered here would be a logical and important extension of this research.
3. Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the logical inconsistencies discussed by Livernois and Uhler (1987), Livernois (1987, 1988) and Swierzbinski and Mendelsohn (1989). These authors argue that Pindyck's extraction cost function is defensible when reserves are of uniform quality but in the presence of exploration, reserves must be treated as heterogeneous because the most accessible deposits are added to the reserve base first. They show that aggregation of extraction costs across heterogeneous deposits is not valid except under special circumstances. Another problem with this function is that extraction costs should be a function of γ. The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have γ as an argument because the reserve base is an input to oil and gas production. These complications are not treated in the analysis below because of severe data constraints on estimating the extraction cost function (see Section 3.2).

4. Equation (11) can be simplified by choosing a functional form for reserve additions such as the one used in Section 3 (see equation (13)). In this case, $(f_{xw}/f_w) \cdot f - f_x = 0$.
5. The Energy Information Administration and the American Petroleum Institute (2000) report annual production data for 31 states over this period, but data on reserve additions, cumulative drilling, and drilling costs are not available in all years for the 11 smallest producing states. The 20 states included are AK, AL, AR, CA, CO, IL, IN, KS, KY, LA, MI, MS, MT, ND, NE, NM, OK, TX, UT, and WY.
6. Major cost items are for labor, materials, supplies, machinery and tools, water, transportation, fuels, power, and direct overhead for operations such as permitting and preparation, road building, drilling pit construction, erecting and dismantling derricks/drilling rigs, drilling hole, casing, hauling and disposal of waste materials and site restoration. For additional details, see Joint Association Survey on Drilling Costs, Appendix A (1998).
7. Equation (13) was also estimated allowing for both state-specific intercepts and state-specific coefficients for ρ and β. This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.
8. Wyoming rescinded this legislation in 2000.

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