The Economics of CO_2 Sequestration through Enhanced Oil Recovery

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Abstract

In this paper, we provide an overview of the economics of CO_2-enhanced oil recovery (EOR), considering the influence of climate-change policy on optimal management of CO_2-EOR projects. EOR is a significant and rapidly growing portion of oil production in the US. This is an important development for climate-change policy as most of the injected CO_2 remains underground after fields are decommissioned. If the injected CO_2 comes from anthropogenic sources, EOR therefore constitutes a form of carbon capture and sequestration. The potential magnitude of this sequestration potential is substantial; recent estimates indicate EOR has the potential to sequester emissions from more than 90 one-gigawatt-size coal-fired power plants for 30 years. In addition, these projects generate revenues from the incremental oil that they recover. While EOR projects currently treat CO_2 as a costly input, operators may receive carbon credits, tax credits, or other types of subsidies for any CO_2 they sequester in the context of climate-change policy. Because these subsidies then become a new source of revenues, additional to revenues from oil, the question arises how operators should "co-optimize" oil recovery and CO_2 sequestration.

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1. Introduction

The process of injecting CO_2 into mature oil fields to increase oil production, referred to as CO_2-enhanced oil recovery (CO_2-EOR), contributes a significant and rapidly growing portion of oil production in the US. According to the most recent biannual survey of EOR production by the *Oil and Gas Journal* (Koottungal, 2012), CO_2-EOR projects now produce about 350,000 barrels/day (5.6% of total US oil production), compared to just 190,000 barrels/day (3.2%) in the year 2000. This is an important development for climate-change policy, because almost all of the injected CO_2 remains underground after fields are decommissioned. Provided therefore that the CO_2 comes from anthropogenic sources, EOR constitutes a form of carbon capture and sequestration (CCS). Moreover, whereas projects that inject CO_2 into saline aquifers incur only costs, EOR projects generate revenues from the incremental oil that they recover. Recognizing perhaps the political advantage in emphasizing that captured CO_2 can generate economic value, the US Department of Energy (DOE) has in fact recently "re-branded" CCS to CCUS—the "U" standing for "utilization," mostly in CO_2-EOR projects (Marshall, 2012). The DOE's most recent report on CO_2-EOR (Kuuskraa et al., 2010) dramatizes the sequestration potential of CO_2-EOR projects by estimating that they could collectively sequester the emissions from as many as 93 one-GW-size coal-fired power-plants for 30 years. In addition, it has widely been argued that promoting CO_2-EOR may provide a "bridge" to widespread capture of CO_2 for storage in aquifers (which have far greater sequestration capacity), by helping pay for required infrastructure.[1]

In this paper, we provide an overview of the economics of CO_2-EOR. Our focus thereby is on insights from economic analysis that engineering studies have tended to overlook.

We first consider how climate-change policy may influence optimal management of CO_2-EOR projects. Currently, these projects treat CO_2 as a costly input, the use of which should be minimized. In the context of climate-change policy, however, operators may receive carbon credits, tax credits, or other types of subsidies for any CO_2 they sequester. Because these subsidies then become a new source of revenues, additional to revenues from oil, the question arises how operators should "co-optimize" oil recovery and CO_2 sequestration.

[1] See, *e.g.*, ARI (2010); MIT (2010); Steelman and Tonachel (2010), but see also Dooley et al. (2010) for a dissenting view.

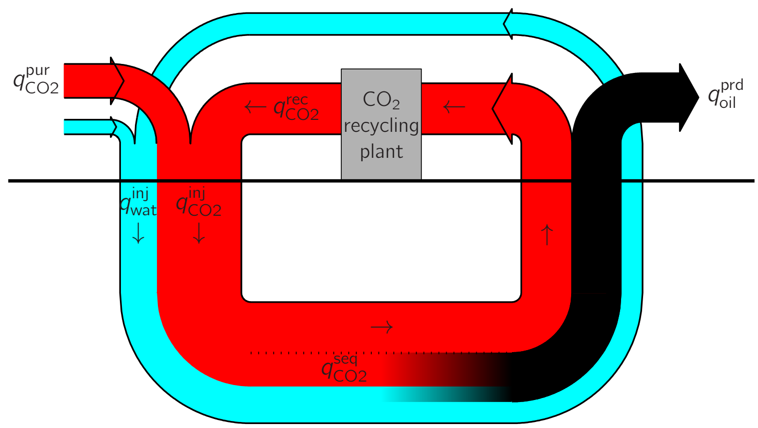


FIGURE 1. Schematic of fluid flows in a CO_2-EOR project.

2. Modeling Oil Production

Several engineering studies (Asghari and Al-Dliwe, 2004; Jessen et al., 2005a; Kovscek and Cakici, 2005; Babadagli, 2006; Forooghi et al., 2009; Pamukçu and Gumrah, 2009; Ghomian et al., 2010; Jahangiri and Zhang, 2011) have addressed this question of co-optimization, examining how operators might modify well-completion, -spacing, and -control decisions, as well as the sequencing of CO_2 and water injection. The usefulness of these studies is limited, however, by the ad hoc criterion used to compare these decisions: the operator is usually assumed to maximize a simple weighted sum of cumulative oil recovery and cumulative CO_2 sequestration. More realistically, operators will maximize the net present value (NPV) of project profits—discounted oil and sequestration revenues less operating and investment costs—which we find may result in quite different management decisions.

One such difference is that, whereas engineering studies tend to hold CO_2 injection constant, NPV maximization dictates a gradually declining CO_2-injection rate, to save on CO_2 recycling costs. To see why, consider the schematic of a CO_2-EOR flood shown in Figure 1.

On the left, water and compressed CO_2 are injected into the reservoir ($q^{\text{inj}}_{\text{wat}}$ and $q^{\text{inj}}_{\text{CO}_2}$), usually in alternating slugs—a process referred to as "water alternating gas" (WAG) injection. Inside the reservoir, the injected fluids help move oil towards production wells. In the process of doing so, some fraction of the injected CO_2 remains sequestered in the reservoir ($q^{\text{seq}}_{\text{CO}_2}$), taking up pore space vacated by the oil, as does some fraction of the injected water. On the right, a mixture of CO_2, oil, and water flows out of production wells and is separated at the surface into flows of oil ($q^{\text{prd}}_{\text{oil}}$), recycled and recompressed CO_2 ($q^{\text{rec}}_{\text{CO}_2}$) and recycled water. In order to maintain a given injection ratio of water and CO_2, the recycled flows are supplemented with new water and new, purchased CO_2 ($q^{\text{pur}}_{CO_2}$).

These physical flows give rise to the following profit flow from an EOR project in a given period (a year, say):

$$\text{profit} = \underbrace{p_{\text{oil}} q^{\text{prd}}_{\text{oil}}}_{\substack{\text{oil}\\ \text{revenues}}} + \underbrace{s_{CO_2} q^{\text{seq}}_{CO_2}}_{\substack{CO_2\\ \text{sequestration}\\ \text{subsidies}}} - \underbrace{p_{CO_2} q^{\text{seq}}_{CO_2}}_{\substack{CO_2\\ \text{purchase}\\ \text{costs}}} - \underbrace{c^{\text{rec}} q^{\text{rec}}_{CO_2}}_{\substack{CO_2\\ \text{recycling}\\ \text{costs}}} - \underbrace{c^{\text{oth}}}_{\substack{\text{other}\\ \text{costs}}}, \tag{1}$$

where p_{oil} and p_{CO_2} represent the unit prices of oil and CO_2 in the given period, s_{CO_2} any unit subsidy for CO_2 sequestration, c^{rec} the unit cost of CO_2 recycling (which is a major flow expense of any EOR project), and finally c^{oth} other operating costs (overhead, labor, maintenance, etc.).

For our economic analysis, it is useful to rearrange this profit expression, using two identities that follow from the schematic of Figure 1.

First, the schematic shows that if a given CO_2 injection flow is to be maintained, CO_2 purchases must make up for CO_2 sequestration, so $q^{\text{pur}}_{CO_2} = q^{\text{seq}}_{CO_2}$. Using this identity, we can merge the CO_2 sequestration subsidies term $s_{CO_2} q^{\text{seq}}_{CO_2}$ and the CO_2 purchase costs term $p_{CO_2} q^{\text{pur}}_{CO_2}$ into a single term $(s_{CO_2} - p_{CO_2}) q^{\text{seq}}_{CO_2}$. That is, we subtract from the subsidy s_{CO_2} for each unit sequestered the price p_{CO_2} of the additional unit of CO_2 that will have to be purchased in order to make up for the sequestration and maintain the CO_2 injection flow: this price is in effect an indirect cost of sequestration.

Second, the schematic shows that the quantity of CO_2 recycled is just the quantity injected less that sequestered, so $q^{\text{rec}}_{CO_2} = q^{\text{inj}}_{CO_2} - q^{\text{seq}}_{CO_2}$. Using this identity, we can split the CO_2 recycling costs term $c^{\text{rec}} q^{\text{rec}}_{CO_2}$ into two terms $c^{\text{rec}} q^{\text{inj}}_{CO_2} - c^{\text{rec}} q^{\text{seq}}_{CO_2}$: the first term is the "gross" recycling cost that would have to be incurred if the entire of injected CO_2 came back up and had to be recycled, while the second term is the recycling cost avoided because some of the CO_2 in fact does not come back up, but is sequestered in the reservoir. This avoided cost can therefore be viewed as an indirect benefit of, or revenue from, sequestration, and combined with the term $(s_{CO_2} - p_{CO_2}) q^{\text{seq}}_{CO_2}$ to obtain "net" CO_2 sequestration revenues $(s_{CO_2} - p_{CO_2} + c^{\text{rec}}) q^{\text{seq}}_{CO_2}$.

With these changes, the profit expression becomes

$$\text{profit} = \underbrace{p_{\text{oil}} q_{\text{oil}}^{\text{prd}}}_{\substack{\text{oil}\\ \text{revenues}}} + \underbrace{(s_{\text{CO}_2} - p_{\text{CO}_2} + c^{\text{rec}}) q_{\text{CO}_2}^{\text{seq}}}_{\substack{\text{net CO}_2\\ \text{sequestration}\\ \text{revenues}}} - \underbrace{c^{\text{rec}} q_{\text{CO}_2}^{\text{inj}}}_{\substack{\text{gross CO}_2\\ \text{recycling}\\ \text{costs}}} - \underbrace{c^{\text{oth}}}_{\substack{\text{other}\\ \text{costs}}} \tag{2}$$

Rearranging the expression in this manner is useful, because it shows that *if* it is optimal to maintain CO_2 injection $q_{\text{CO}_2}^{\text{inj}}$ at a constant level, and if all prices and costs can be treated as contant as well, then the profit expression in effect reduces to a weighted sum of oil revenues and CO_2 sequestration:

$$\text{profit} = \underbrace{p_{\text{oil}}}_{\substack{\text{weight}\\ \text{on oil}\\ \text{production}}} \; q_{\text{oil}}^{\text{prd}} + \underbrace{(s_{\text{CO}_2} - p_{\text{CO}_2} + c^{\text{rec}})}_{\substack{\text{weight}\\ \text{on CO}_2\\ \text{sequestration}}} q_{\text{CO}_2}^{\text{seq}} - \underbrace{c^{\text{rec}} q_{\text{CO}_2}^{\text{inj}}}_{\substack{\text{gross CO}_2\\ \text{recycling}\\ \text{costs}}} - \underbrace{c^{\text{oth}}}_{\substack{\text{other}\\ \text{costs}}} \;. \tag{3}$$

That is, it reduces to the objective function used in the above-cited engineering studies, with the oil price p_{oil} and the "net price" of sequestration $(s_{\text{CO}_2} - p_{\text{CO}_2} + c^{\text{rec}})$ as weights.

In reality, however, it is *not* optimal to hold CO_2 injection constant. This is because, although a successful CO_2-EOR project initially sees a bump in oil production, eventually (usually within a few years) the oil flow peaks and thereafter gradually declines, for purely physical reasons: progressively less oil remains in the reservoir, and that remaining oil is progressively harder to dislodge. Concominantly, because progressively less oil vacates pore spaces in the reservoir rock, the flow of CO_2 sequestered in those pore spaces declines as well.

As a result, both revenue streams from the EOR project fall over time as well.[2] In other words, the *benefits* of CO_2 injection fall over time: the whole point of injecting CO_2 is precisely to generate these oil and sequestration revenues. But then, if the benefits of injection fall, it cannot be optimal (*i.e.*, profit maximizing) to keep injecting at a constant rate, thereby keeping the costs of injection constant. Rather, it is optimal to gradually reduce the injection rate, thereby reducing costs in line with benefits.

This in turn has two implications for the objective function of EOR operators. First, rather than casting the objective as a weighted sum of oil production and CO_2 sequestration alone (minus constant terms), the objective should include a third, injection term, with the cost of recycling as

[2] Assuming, of course, that the oil price and net CO_2 price stay relatively constant and in particular do not increase rapidly enough to offset the decline in oil production and CO_2 sequestration.

its weight:

$$\text{profit} = \underbrace{p_{\text{oil}}}_{\substack{\text{weight}\\\text{on oil}\\\text{production}}} q_{\text{oil}}^{\text{prd}} + \underbrace{(s_{\text{CO}_2} - p_{\text{CO}_2} + c^{\text{rec}})}_{\substack{\text{weight}\\\text{on CO}_2\\\text{sequestration}}} q_{\text{CO}_2}^{\text{seq}} - \underbrace{c^{\text{rec}}}_{\substack{\text{weight}\\\text{on CO}_2\\\text{recycling}}} q_{\text{CO}_2}^{\text{inj}} - \underbrace{c^{\text{oth}}}_{\substack{\text{other}\\\text{costs}}} . \tag{4}$$

Second, because all three flows vary over time (and not in lockstep), the time value of money should be taken into account: changes in the flows because of from operating decisions and resulting changes in revenues and costs should matter more to the operator, the earlier in the lifetime of an EOR project they occur. That is, the objective should not just be profit in any given time period t or the simple sum of profits over the project's lifetime T,[3] but rather the sum of discounted profits or net present value,

$$NPV = \sum_{t=0}^{T} \frac{1}{(1+r)^t} \left[p_{\text{oil},t} q_{\text{oil},t}^{\text{prd}} + (s_{\text{CO}_2,t} - p_{\text{CO}_2,t} + c_t^{\text{rec}}) q_{\text{CO}_2,t}^{\text{seq}} - c_t^{\text{rec}} q_{\text{CO}_2,t}^{\text{inj}} - c_t^{\text{oth}} \right]. \tag{5}$$

In previous work (Leach et al., 2011), we used an extremely stylized model of an EOR project to confirm the intuitive argument above suggesting that optimal CO_2 injection should fall over time. At the heart of the model are just two assumptions, both of which involve the CO_2 injection fraction at any given point in time, $f_{\text{CO}_2,t}^{\text{inj}} \equiv q_{\text{CO}_2,t}^{\text{inj}} / (q_{\text{CO}_2,t}^{\text{inj}} + q_{\text{wat},t}^{\text{inj}})$:

Assumption 1. *Oil production at any point in time is a fraction of remaining recoverable reserves, whereby this fraction is an inverse U-shaped function of the CO_2 injection fraction:*

$$q_{oil,t}^{prd} = \delta(f_{CO_2,t}^{inj}) \times R_{oil,t} \tag{6}$$

Assumption 2. *CO_2 sequestration at any point in time is the product of the CO_2 injection fraction and oil production:*

$$q_{CO_2,t}^{seq} = f_{CO_2,t}^{inj} \times q_{oil,t}^{prd} \tag{7}$$

The first assumption captures two stylized facts about oil production from EOR projects. One is that, after an initial jump, production declines at a roughly exponential rate over time when the injection fraction is held constant. The other is that oil recovery is maximized when a mix of CO_2 and water is injected, using alternating slugs. The slugs of water serve to increase the the area of

[3] Given constant weights, the latter would be equivalent to a weighted sum of cumulative oil production, CO_2 sequestration, and CO_2 injection.

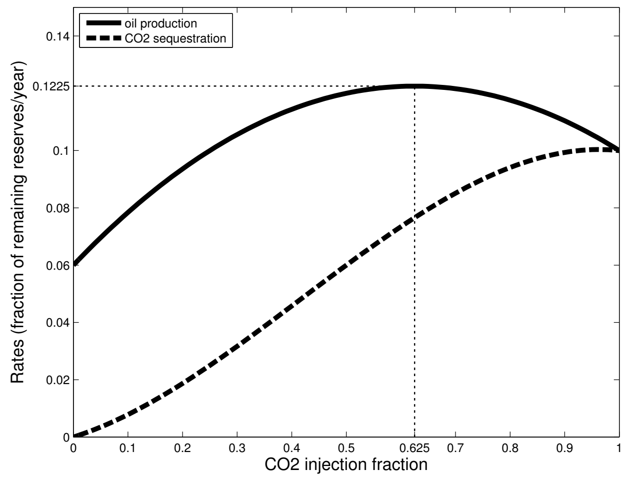


FIGURE 2. Assumed relationship between CO_2 injection, oil production, and CO_2 sequestration.

$R_{\mathrm{oil},0}$	10	Initial recoverable reserves (million barrels)
q^{inj}	10	Combined injection of CO_2 and water (million barrels/year)
p_{CO_2}	4	CO_2 purchase cost (\$/barrel)
c^{rec}	1	CO_2 recycling cost (\$/barrel)
c^{oth}	1	Other costs (\$ million)
I	27	Up-front capital cost of switching to CO_2 flood (\$ million)
r	5	Discount rate (%/year)

TABLE 1. Baseline parameter values.

the reservoir that the slugs of CO_2 sweep through, by reducing the tendency of CO_2 to "finger" or "channel" between injection and production wells, bypassing some of the oil.[4]

The second assumption reflects the fact that both injected fluids end up occupying the pore space vacated by produced oil. It seems reasonable that they should end up doing so roughly in proportion to their ratio in the injection mix.

Figure 2 shows the relationship between the CO_2 injection rate and the oil production and CO_2 sequestration rates implied by these assumptions, if the δ function is a simple quadratic $\delta(f^{\mathrm{inj}}_{\mathrm{CO}_2,t}) = 0.06 + 0.2 f^{\mathrm{inj}}_{\mathrm{CO}_2,t} - 0.16(f^{\mathrm{inj}}_{\mathrm{CO}_2,t})^2$.

Importantly, this functional form and its coefficients are merely illustrative: although they are loosely based on data from a simulation study by Guo et al. (2006) as well as on experience at the Lost Soldier-Tensleep EOR project in Wyoming, the actual shape of the functions is likely to be highly dependent on the specific properties of any given reservoir and of the oil it contains.

[4] See, *e.g.*, Al-Shuraiqi et al. (2003), Jessen et al. (2005b), Juanes and Blunt (2006), Guo et al. (2006), and Trivedi and Babadagli (2007).

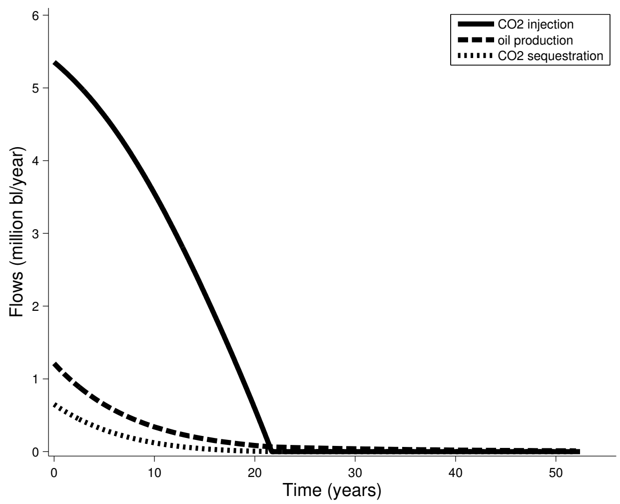


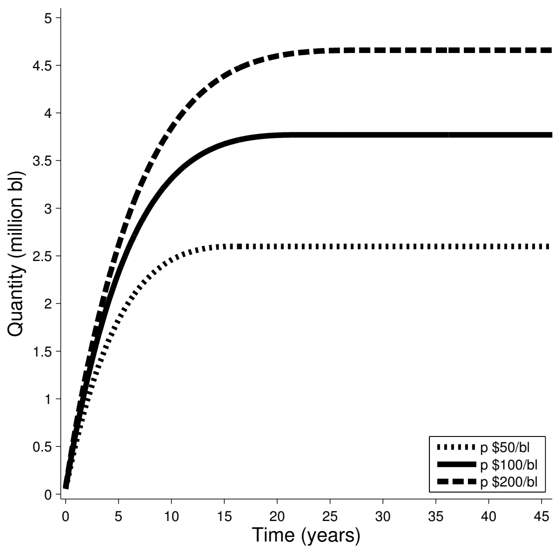
FIGURE 3. Baseline simulation results.

The full model consists of objective function (5), equations (6) and (7), and an equation $R_{\mathrm{oil},t+1} = R_{\mathrm{oil},t} - q^{\mathrm{prd}}_{\mathrm{oil},t}$ to update remaining reserves in each period. Using the parameter values given in Table 1,[5] we solve the model numerically for the combination of terminal time T and vector of CO_2 injection rates $q^{\mathrm{inj}}_{CO_2,0}, q^{\mathrm{inj}}_{CO_2,1}, q^{\mathrm{inj}}_{CO_2,2}, \cdots, q^{\mathrm{inj}}_{CO_2,T}$ up to that time that maximize NPV.

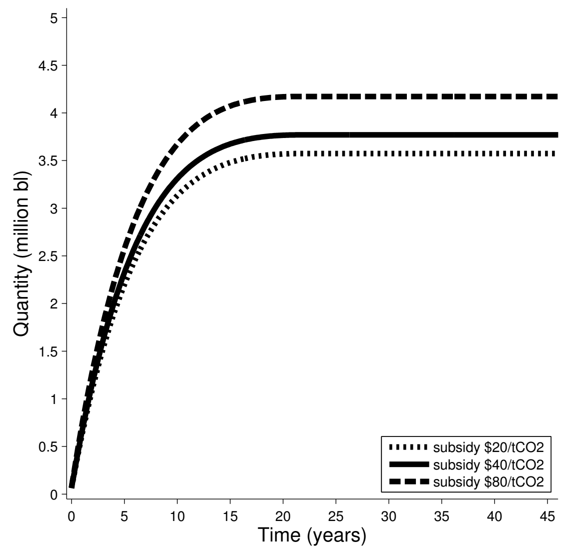
Figure 3 shows the result at our baseline oil price of \$100/bl and baseline CO_2 sequestration subsidy of \$4/bl ($\approx$ 40/tCO_2). At these values, it is optimal to intially inject a mix of about 50% CO_2 and water, but to gradually drop the CO_2 fraction over time. After 22 years, the optimal fraction drops to zero, after which the project optimally continues to operate for another 31 years (so the optimal terminal time T is 53 years) while injecting only water.

Paradoxically, when we then re-run the simulations for a range of oil prices and CO_2 subsidies, we find that cumulative CO_2 sequestration is much more responsive to the oil price than to the sequestration subsidy. As shown in Figure 4, halving the subsidy to \$20/tCO_2 reduces cumulative sequestration by only about 5%, while doubling the subsidy to \$80/tCO_2 increases cumulative sequestration by only 11%. In contrast, halving the oil price to \$50/bl reduces cumulative sequestration by 36%, and doubling the oil price to \$200/bl increases cumulative sequestration by 42%.

[5] Note that we measure CO_2 in barrels rather than the more conventional units of mcf (1,000 cubic feet at standard surface temperature and pressure conditions) or tCO_2 (1 metric tonne). At the temperature and pressure conditions inside the Lost-Soldier Tensleep reservoir, 1 mcf of CO_2 is compressed to about 0.471 barrels, which we round off to 0.5 bl/mcf. The standard conversion factor between mcf and tCO_2 is about 18.9, which we round off to 20 mcf/tCO_2. See Leach et al. (2011) for further details.



(a)



(b)

FIGURE 4. Sensitivity of cumulative sequestration to (a) the oil price (b) the sequestration subsidy.

The reason is quite straightforward: at realistic oil-price and sequestration-subsidy levels, oil revenues make up a far larger share of a project's profits than do sequestration revenues. In terms of equation (4) above, not only is the sequestration rate $q^{\text{inj}}_{\text{CO}_2}$ is over most of the project's lifetime less than half as large as the oil production rate $q^{\text{prd}}_{\text{oil}}$ (when both are expressed in comparable units such as bl/year) but its weight is orders of magnitude smaller: over the range of subsidies and prices considered in Figure 4, the weight on sequestration varies from \$-1 to \$5, while that on oil production varies from \$50 to \$200. As a result, the operator's incentive, even with sequestration subsidies as high as \$80/tCO$_2$, is to largely ignore sequestration and instead manage the project so as to maximize oil production alone.

The relationship between oil production and sequestration shown in Figure 2, however, implies that increasing oil production even slightly in response to a higher oil price may require injecting, and hence sequestering, large amounts of additional CO$_2$. For example, we find that if the oil price doubles from \$100 to \$200, the operator's optimal CO$_2$ injection rate over the first 30 years of the project increases 45%, from 2.26 million bl/year to 3.29 million bl/year. Doing so increases average oil production by only 2%, from 0.312 million bl/year to 0.318 million bl/year, but this implies a revenue boost from oil sales of \$1.2 million/year. At the same time it increases average CO$_2$ sequestration by 24%, from 0.126 million bl/year to 0.155 million bl/year, but this implies a revenue boost from sequestration subsidies of only \$0.12 million/year. From the operator's point of view, then, the boost in CO_2 sequestration, while significant in quantity terms, is just a "side effect" in dollar terms.

Conversely, even very high sequestration subsidies will not induce the operator to alter project management by much. A true tradeoff between oil revenues and CO_2 sequestration emerges only when the subsidy reaches levels as high as \$120/tCO_2 (well above realistic levels in the near future), and even then, the operator will optimally give up only very small amounts of oil production in order to boost CO_2 sequestration. In terms of Figure 2, it is only at these very high CO_2 subsidy levels that the operator will briefly, at the very beginning of the flood, choose a CO_2 injection fraction higher than the oil-production-maximizing fraction of 0.625.

While the preceding result suggests that climate policy should perhaps focus on raising oil prices rather than on subsidizing CO_2 sequestration, we find this need not be the case. There are two reasons.

First, we find—in an extension of our previous work that incorporates possible changes in oil prices or CO_2 subsidies over time (Leach et al., 2010)—that rapid increases in the oil price, if anticipated by operators, may greatly reduce sequestration by CO_2-EOR projects. As shown in panel (b) of Figure 5, cumulative sequestration from our model project drops by as much as 53%, from 3.77 million bl to 1.78 million bl, if instead of staying constant at \$100/bl, the oil price increases at a rate of 7.5% per year.

Underlying this is the fact that large up-front investment costs are required to switch from conventional oil-recovery methods, such as waterflooding, to CO_2 injection. That is, the full expression for the net present value of a project is

$$NPV = -I + \sum_{t=0}^{T} \frac{1}{(1+r)^t} \left[p_{\mathrm{oil},t} q^{\mathrm{prd}}_{\mathrm{oil},t} + (s_{\mathrm{CO_2},t} - p_{\mathrm{CO_2},t} + c^{\mathrm{rec}}_t) q^{\mathrm{seq}}_{\mathrm{CO_2},t} - c^{\mathrm{rec}}_t q^{\mathrm{inj}}_{\mathrm{CO_2},t} - c^{\mathrm{oth}}_t \right], \tag{8}$$

where I is the up-front investment cost.

In general, oil field operators have an incentive to delay switching in order to delay these investment costs. When oil prices are anticipated to increase, there is an additional incentive to delay: by so doing, the CO_2-induced boost in oil production is pushed back to a time when oil prices are higher. But the extension of waterflooding until this later switching time also reduces CO_2 sequestration. This is because reservoir pore space that would have been occupied by CO_2 had EOR commenced sooner will now be occupied by water.

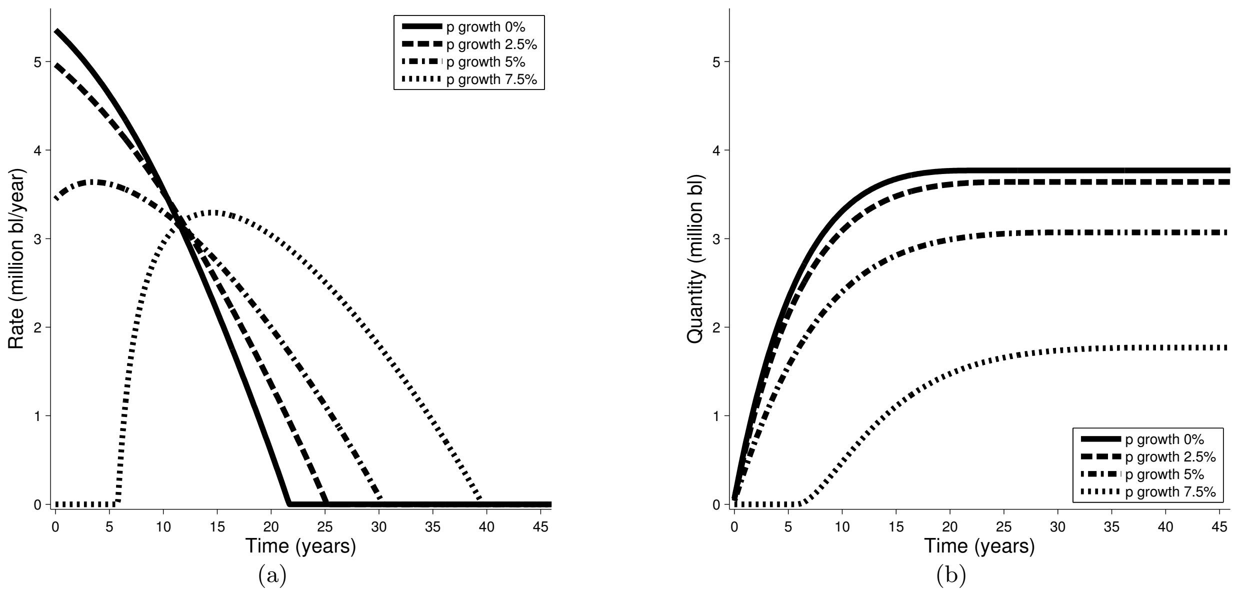


Figure 5. Sensitivity of cumulative sequestration to (a) the oil price (b) the sequestration subsidy.

Second, and independent of the first effect, when the incremental oil recovered by EOR projects is consumed, additional CO_2 emissions will be generated. A common misconception is that these emissions can be ignored, ostensibly because incremental oil from EOR merely "displaces" conventionally produced oil.

In their study of net sequestration by eight North American CO_2-EOR projects, Faltinson and Gunter (2011) suggest, for example, that

> "Project-life-cycle emissions attributed to CO_2 EOR should include fugitive emissions directly related to the CO_2-EOR project only, and not include downstream emissions common to all sources of oil supply."

This is because, they argue,

> "World oil production is determined by world oil demand and if CO_2-EOR projects were not undertaken, *some other source of oil would step forward and fill the gap.* Therefore, executing CO_2-EOR projects will not result in incremental aggregate refining and consumption emissions" (emphasis added).

This line of reasoning presumes, however, that aggregate world demand for oil is fixed, *i.e.*, perfectly insensitive to price. If so, any drop in the oil price caused by increasing EOR supply will induce no expansion of demand, forcing marginal conventional oil projects to cut back production by exactly the amount of EOR production added. Realistically, however, world demand is price sensitive (particularly in the long run), and incremental EOR production therefore does expand aggregate consumption and emissions.

3. Market Equilibria

We provide a graphical illustration of the oil market, based on the model previously described. For expositional simplicity, we discuss only the first two periods of a multi-period story. In this setting, we refer to the current time frame as "period 0" and the future as "period 1." At the start of a given period t, firms collectively have remaining reserves r_t^{con}, where the superscript indicates that these reserves have been developed using conventional technology. Of these reserves, at most a given proportion δ can be extracted. Under a wide range of conditions, this constraint will bind, allowing us to focus on the role played by current "developed" reserves. To produce a greater level of output, new reserves must be added to the portfolio, a process that involves exploration and development. Here we do not describe these steps in any detail; rather, we focus on the impact these "additions" a^{con} will have on the problem.

Adding reserves is costly, with the total cost given by $c(a^{\text{con}}, A^{\text{con}})$, where A^{con} is cumulative additions at the current time. One can think of a story in which the relatively easy to find and develop reserves are added sooner, in which case the costs of adding reserves naturally rise as cumulative additions mount. With this intuition in mind, we assume $c_A > 0$; it is also natural to assume that adding more reserves is costly, given any particular level of accumulated additions, so that $c_a > 0$ as well.

In deciding what level of additions to bring forward at time 0, the (discounted) stream of operating profits is compared against the (up front) development costs; this implies a cutoff price, $\hat{p}_0$, that would just generate the requisite stream of profits. Viewed through this lens, one can think of the incremental cost of bringing forward greater levels of additions as comprising an increasing supply schedule. We denote the available reserves in period t (after the new additions are brought on line) as $R_t^{\text{con}} \equiv r_t^{\text{con}} + a_t^{\text{con}}$; based on these available reserves, output is $Q_t^{\text{con}} = \delta R_t^{\text{con}}$. Within the period, the market equilibrium price equates the incremental cost associated with this supply schedule to the willingness to pay for that last barrel of oil, as reflected by the market demand curve.

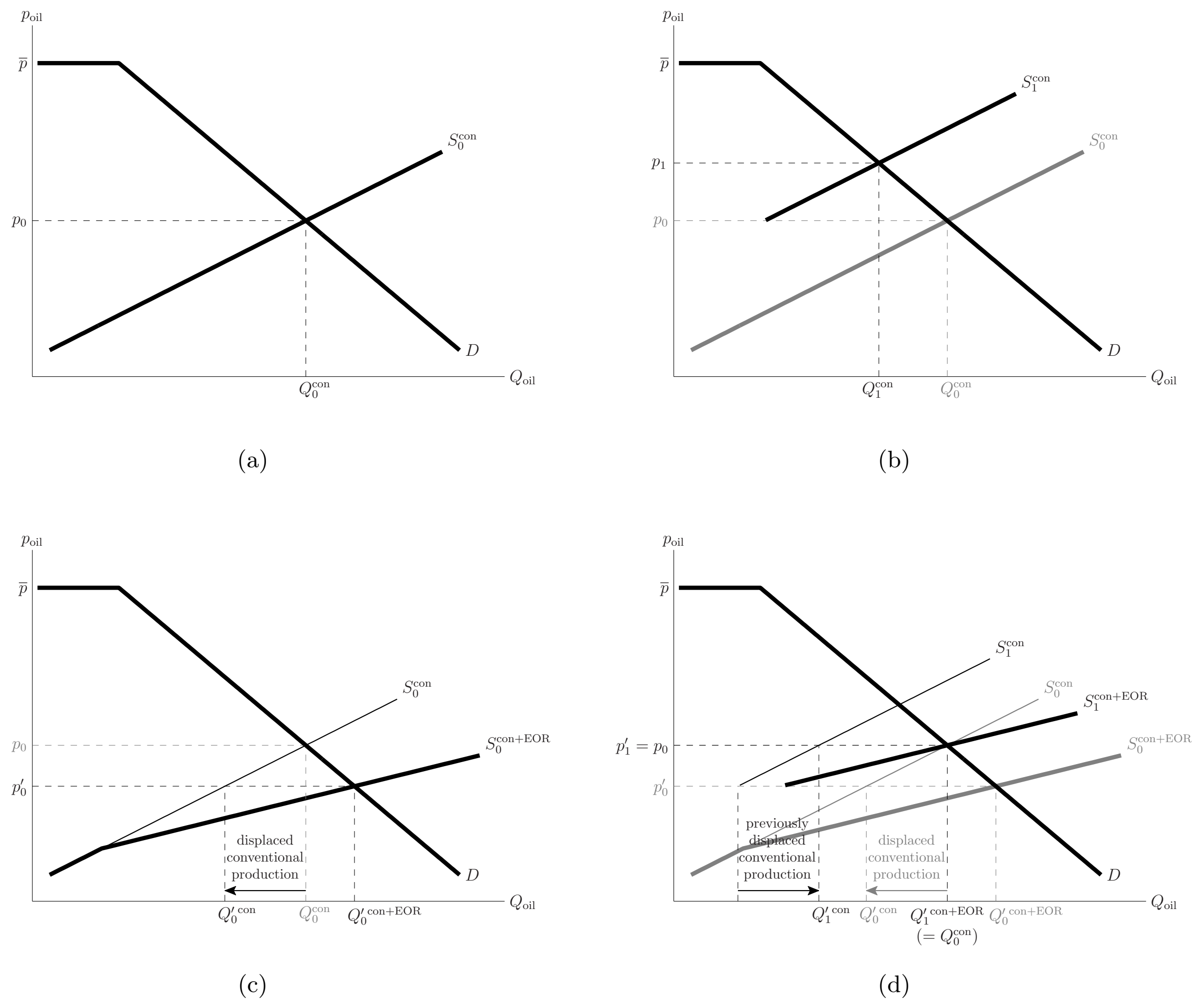


Figure 6. Stylized representation the world oil market at two periods in time, without (panels (a) and (b)) or with additional production from CO_2-EOR (panels (c) and (d)).

Writing the optimal level of new additions in period 0 be a_0^{con}, total output delivered to market is then $Q_0 = \delta(r_0^{\text{con}} + a_0^{\text{con}})$. The market-equilibrium price corresponding to this level of output, illustrated in panel (a) of Figure 6, is p_0.

Now consider the next period. The remaining reserves at the start of the period are $r_1^{\text{con}} = (1-\delta)R_0^{\text{con}}$, the fraction of period-0 available reserves that was not extracted. Again, firms may add to these reserves, up to the point where the last barrel added brings a profit stream that just covers the current development cost. Because the depletion effect associated with period 0 production reduces the amount that can be produced in period 1, the supply curve shifts in (leftward) between periods 0 and 1.[6] As a result, the market equilibrium price increases from p_0 to p_1. This point is illustrated in panel (b) of Figure 6.

In this framework, imagine firms discover the potential to add to reserves via CO_2-EOR. This technique is similar to additions, in that it raises the available stock of reserves, but it is cheaper to incorporate. The increased production that EOR facilitates induces an outward tilting of the supply curve, above some new threshold price; panel (c) of Figure 6 illustrates. With this new supply curve, the market equilibrium price falls and equilibrium quantity rises.[7]

Importantly, the increase in market quantity implies that the new output associated with EOR must more than offset the reduction in output from conventional sources that are not brought to market in period 0. That is, the oil production "displaced" by EOR is smaller than the increase due to EOR, contrary to arguments that have been made. Note too that this "displaced" production is associated with new additions that are no longer economic as a result of the lower price that follows naturally from the increase in supply arising from EOR. While these additions are not brought on line in period 0, they are nevertheless still available in the future.

Because of the upward-sloping nature of the incremental cost curve for additions, some additions to conventional developed reserves remain economic even with the lower price; call the corresponding optimal level of additions ${a'}_0^{\text{con}}$. The net effect on output in period 0 is an increase, from

$$Q_0^{\text{con}} = \delta R_0^{\text{con}} = \delta(r_0^{\text{con}} + a_0^{\text{con}})$$

to

$${Q'}_0^{\text{con+EOR}} = \delta {R'}_0^{\text{con+EOR}} = \delta(r_0^{\text{con}} + {a'}_0^{\text{con}} + a_0^{\text{EOR}}).$$

At the start of period 1, remaining reserves are now

$${r'}_1^{\text{con+EOR}} = (1-\delta){R'}_0^{\text{con+EOR}} = (1-\delta)(r_0^{\text{con}} + {a'}_0^{\text{con}} + a_0^{\text{EOR}}),$$

and so if without any further additions, supply would equal

$$\delta {r'}_1^{\text{con+EOR}} = \delta(1-\delta)(r_0^{\text{con}} + {a'}_0^{\text{con}} + a_0^{\text{EOR}}).$$

[6] In addition, the time horizon is shorter (the backstop is more imminent) in period 1, so there is a shorter time frame to enjoy these profits, which raises the price required to motivate development must be greater than it was in period 0. This effect is of second-order importance in our scenario, and so we abstract from it in the pursuant discussion.
[7] This reduction in price obtains so long as demand is not perfectly elastic.

This supply level corresponds to the intercept of the supply curve labeled $S_1^{\text{con+EOR}}$ in panel (d) of Figure 6. The supply curve labeled S_1^{con} represents the component of overall supply that is provided by conventional sources, and has intercept

$$\delta r'^{\text{con}}_1 = \delta(1-\delta)(r_0^{\text{con}} + a'^{\text{con}}_0).$$

Because at p'_0, demand exceeds $\delta r'^{\text{con+EOR}}_1$, the new market equilibrium entails a higher price p'_1. To avoid clutter, we have set this price to correspond with the original period-0 price in the absence of EOR, p_0.[8]

At this price $p'_1 = p_0$, further additions to both conventional and EOR reserves become economic and are brought into production. Importantly, by our convenient assumption that $p'_1 = p_0$, the period-1 additions to conventional reserves that become economic, a'^{con}_1, are precisely those additions that would have been economic in period 0 in the absence of EOR, but became uneconomic as a result of the price drop from p_0 to p'_0. That is, $a'^{\text{con}}_1 = a_0^{\text{con}} - a'^{\text{con}}_0$. It follows that the conventional production out of these additions that would have been supplied in period 0, but was displaced, becomes part of overall production in period 1. The displacement is therefore only temporary: in this case it merely involves a one-period delay.

More generally, the ultimate impact of CO_2-EOR upon cumulative oil production depends on the impacts in multiple periods. Panel (a) of Figure 7 compares the oil-price path with only conventional production, p_t^{con}, to that with added production from CO_2-EOR, $p'^{\text{con+EOR}}_t$. Let T^{con} and $T^{\text{con+EOR}}$ denote the times at which the oil price reaches $\overline{p}$ in the scenario without and with CO_2-EOR, respectively. Under both scenarios, the oil price increases over time. However, the addition of CO_2-EOR production raises production in each period, as illustrated in panel (b) of Figure 7. In every such period, the increased production implies a lower price, and so the oil-price path $p'^{\text{con+EOR}}_t$ lies below the oil-price path p_t^{con} in panel (a).

At a certain point, each path hits a price ceiling $\overline{p}$, above which oil demand drops to zero. This is because $\overline{p}$ represents the price of a renewable, "backstop" technology that is a perfect substitute for oil. At this price, oil production may still continue for some time, but no additions to reserves are made. Since the path $p'^{\text{con+EOR}}_t$ lies below the path p_t^{con}, it follows that $T^{\text{con+EOR}} > T^{\text{con}}$. In the example illustrated in panels (a) and (b) of Figure 7, where the backstop price does not change

[8] Of course, this scenario is coincidental. But our central point, that the net effect of introducing EOR will only be neutral in terms of the impact on ultimate oil production under very special circumstances, does not depend on this graphical assumption.

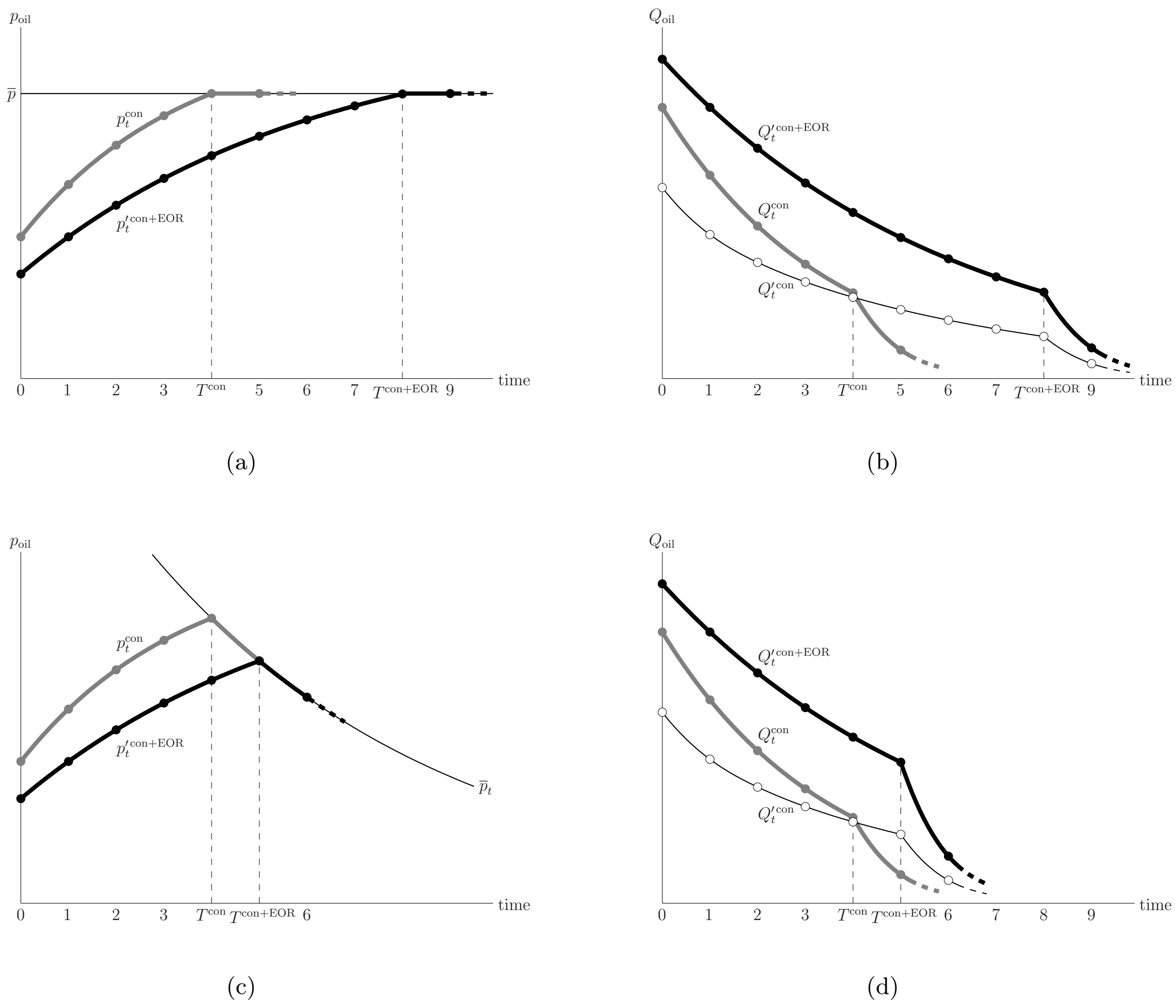


FIGURE 7. Oil-price and oil-production paths with and without CO_2-EOR, when the price of the backstop technology is either constant (panels (a) and (b)) or falling over time (panels (c) and (d))

over time, $T^{\text{con}} = 4$, whereas $T^{\text{con+EOR}} = 8$. Importantly, because the backstop price is constant, all conventional projects that are economic without the introduction of EOR eventually become economic also when EOR is introduced. As a result, the accumulated amount of oil produced from conventional sources is unaffected (*i.e.*, the areas under the oil-quantity paths Q_t^{con} and Q'^{con}_t are identical). In other words, EOR production ultimately displaces no conventional oil production at all.

If, on the other hand, the backstop price falls over time, matters are more complex.[9] In this scenario, the outward shift in the oil price implies that there is more time for the backstop price to decline, and as a result the backstop is reached at a lower price. Panel (c) of Figure 7 illustrates this point. This lower "terminal" oil price in turn induces a reduction in cumulative additions (*i.e.*, the area under the oil-quantity path Q'^{con}_t in panel (d) is smaller than the area under the oil-quantity path Q^{con}_t). Ultimately, the net effect on total production turns on a comparison of this induced reduction on the one hand with the increased output associated with EOR on the other.

4. CONCLUSION

In this paper, we have investigated the impact of EOR on oil markets, paying specific attention to the interplay of supply and demand across time. A key result is that the introduction of EOR displaces oil production early on, as the lower prices that result from a supply expansion render some potential additions uneconomic. But over time, as depletion occurs and prices rise, the erstwhile displaced projects become economic. Accordingly, the introduction of EOR may not displace any production, though it necessarily will delay the development of some new sources of production. In the end, then, introduction of EOR will necessarily increase the total accumulated amount of oil produced. As any extra oil produced will ultimately yield CO_2 emissions, a key issue is how the extra CO_2 emissions associated with the net increase in oil extraction compares to the amount of CO_2sequestered by EOR.

If the critical price at which the economy switches from oil to another energy source, which we have referred to as the backstop price, is constant across time, then it follows that all production that would have obtained if EOR were never introduced will also (eventually) be brought on line after EOR is introduced. The end result is that the introduction of EOR must necessarily raise total accumulated oil production by the time the backstop is adopted, with the amount of extra production corresponding to the level of oil produced by EOR. If the level of CO_2 sequestered by EOR is roughly equivalent to the amount of CO_2 generated by the consumption of this extra oil produced, then introducing EOR has no net effect on carbon emissions. By contrast, if the backstop price falls over time, as one might expect if learning occurs over time, and if this learning makes

[9] There is, we believe, good reason to expect the backstop price to fall: historically, R&D into technologies associated with renewable resources have produced striking cost reductions over time. If this pattern is indicative of likely trends going forward, then there seems to be good reason to anticipate the backstop price will decline over time.

the new technology more efficient, then some of the projects that are pushed out of the market after the introduction of EOR will never be developed. The implication is that the increase in total accumulated amount of oil produced is smaller than that described in the previous paragraph. It then follows that introducing EOR leads to a net reduction in the accumulated amount of CO_2 emitted over time.

In linking the impact of EOR upon carbon stocks, it is tempting to think that the timing of production changes is of paramount importance. But such an approach presumes that damages are linked to carbon stocks (indeed, the typical Integrated Assessment Model follows this approach). But if damages are linked to temperatures, as seems most likely, then the key question is: what effect does a change in the stream of emissions have upon the time path of temperatures? In this regard, Allen et al. (2009) have argued that it is the cumulative amount of CO_2 emitted by, say, 2050 that is of crucial importance, with the time path of those emissions being far less critical. Taking this perspective, the key consideration in evaluating the impact of EOR upon damages is the net effect on cumulative emissions over time.

This then raises the policy question of how to address the fact that, due to both geological factors and differing management practices, net CO_2 emissions by EOR projects vary widely. Whereas some projects sequester far less CO_2 per incremental barrel than the consumption of those barrels will generate, other projects sequester more (therefore arguably producing "green" oil). Presumably, one would want a policy to discourage the former class of projects, while promoting the latter class of projects. Fortunately, a comprehensive tax on CO_2 emissions (or an equivalent cap-and-trade scheme) will accomplish both objectives. It does so indirectly, through induced adjustments in the oil and CO_2 markets that reduce both the oil price that EOR projects receive and the CO_2 price that they pay. A large enough tax will in fact make that CO_2 price negative, thereby effectively acting as a sequestration subsidy. Moreover, these price adjustments will appropriately account for market switching between energy sources, thereby making the above-described "displacement" issue moot.

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