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SUPPLEMENTARY INFORMATION
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Effect of subsidies to fossil fuel companies on United States crude oil production

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Supplementary Information

SUPPLEMENTARY METHODS

As described in the main manuscript, we conduct our field-by-field analysis of the impact of subsidies using detailed economic and production data available in the UCube database, maintained by oil industry consultancy Rystad Energy.[1] Using these cash flow estimates as a starting point, we then include the value of the subsidies by modifying the appropriate portion of cash flow to simulate the use of a particular subsidy – such as depreciation (e.g., for tax provisions that accelerate depreciation) or operating costs (e.g., for subsidies that transfer liability by including the cost of added insurance). We further adjust for eligibility, since not all subsidies apply to all firms or all fields – for example, some are available only to independent (non-integrated) producers or limited to a certain level of production. To model income, we apply the price level being assessed (e.g. US$ 50 per barrel, in real terms) to Rystad's estimated production curve for each asset. The price for the relatively small portion of natural gas produced at each field, if any, is assumed to be US$ 15 per "barrel equivalent" in USD 2016 in all oil price scenarios (equivalent to US$ 2.65 / mcf).

This document describes the rules for which subsidies apply in each circumstance, as well as details about how the modifications were made to the Rystad-provided cash flow streams in order to quantify each specific subsidy.

Treatment of capital expenditures

As described in the Methods section of the manuscript, whether capital expenditures are physical property or, instead, "intangible" has considerable bearing over their U.S. tax consequences. Supplementary Table 1 describes how we assign capital expenditures to be "intangible."

Supplementary Table 1. Description and treatment of capital expenditure categories in Rystad's UCube

Type of capital expenditure	Rystad's description	Fraction we assume is "intangible"
Exploration capex	Exploration expenditures are the costs associated with seismic and drilling wildcats or appraisal wells to discover and delineate oil and gas fields.	85% for onshore (80% for offshore) operators[2] An additional 10% is set aside as geological and geophysical costs that are not eligible for IDC but are eligible for amortization over two years
Facility capex	Facility costs consist of development costs plus modification, maintenance and operation costs. Development costs are those associated with the construction and implementation of the facility required for the processing and production of the field. They depend on location, facility type, and resources. The cost will be \$2–30/bbl. Modification, maintenance and operation costs are expenditures related to maintenance and improvements required to keep the facility operational. The value is calculated as a share of the development costs, and reaches its peak after decline starts.	0% (all are assumed tangible and therefore subject to depreciation)
Well capex	Well capex is estimated by looking at the field type and estimated drilling cost per barrel. Drilling costs depend on water depth, reservoir depth, recovery, region, recovery method and facility type.	85% for onshore (80% for offshore) operators[2]

Methods for quantifying subsidies that reduce government revenue

This section and the ones that follow describe the assumptions used for analysing each tax-related subsidy in our model. Several of these subsidies involve accelerated write-offs of capital investments. Under accrual accounting rules, firms match annual revenues with the costs associated with earning that revenue. This method of accounting requires that multi-year capital assets be written down as they wear out to reflect the annual "consumption" of the asset. Baseline rules for U.S. taxation use this approach, though often assume a shorter life for an asset class than its actual service life. Although this baseline may itself confer a subsidy to capital, we do not count it here. However, when special tax rules allow oil and gas firms to write off the entire capital investment in a single year (expensing), more quickly than the U.S. baseline for that asset class (accelerated depreciation); or for the write-offs to exceed the actual invested capital (percentage depletion), a subsidy ensues and is captured in our analysis. Deductions in the early years of an investment will exceed the actual consumption of capital, and reduce taxes due. While those taxes will have to be paid on a nominal basis later towards the end of the asset's service life, these provisions generate subsidies to firms on a present value basis.

Expensing of intangible exploration and development cost

The largest source of support to the oil and gas industry that we quantify in our analysis is the practice of expensing intangible drilling costs (IDCs). Only items with no salvage value can be claimed as IDCs, such as wages, fuel, and repairs, relating to well drilling.[3] Large capital assets always have a mixture of tangible and intangible investments, and in most other sectors these are all capitalized into the cost basis that is written down over time.

In contrast, producers are allowed to deduct from taxable income IDCs associated with investments in domestic oil and gas wells. These costs include a fraction of exploration and capital expenses for a given well up to the installation of a wellhead.[4] Independent oil and gas operators are able to expense all IDCs immediately, while integrated oil companies may expense 70% of IDCs. The remaining 30% of integrated producers' IDCs still receive special tax treatment, as operators can depreciate IDCs over five years instead of recovering these costs through depletion. We assume that IDCs represent 85% of the cost of drilling a well (as represented by exploration expenditures and capital expenditures for well drilling in Rystad's UCube) for onshore unconventional wells and 80% for offshore wells, as indicated in Supplementary Table 1.[2]

Excess of percentage over cost depletion

Independent oil companies can claim depletion based on a percentage of their revenue, so-called percentage depletion. Employing this percentage-based method of calculating depletion usually results in a larger depletion amount than would be permitted under standard depletion rules (which are capped at total investment). By claiming percentage depletion, operators can deduct a percentage of their gross income each year regardless of their actual resource holdings or production. Independent operators are allowed to claim percentage depletion instead of using cost depletion, in which the annual depletion allowance is dependent on the operator's invested capital, remaining resource holdings and annual resource production.

Because percentage depletion is based on the gross income from a production property rather than the investment into that property (cost basis), the value of this subsidy rises with oil prices. Yet in high price environments, operators are less likely to need economic support.

For oil and gas, percentage depletion is calculated based on 15% of an operator's gross income, or gross sales income less royalty payments. There is an (average) daily cap of 1,000 barrels of crude oil production per property that an operator can use in figuring the depletion deduction. If production from a property exceeds the 1,000 barrel per property per day limit, the percentage depletion deduction is scaled by the ratio of the production cap, on an annual basis, to the asset's total production in that year. In our analysis, offshore assets are assumed to comprise a single property. For onshore assets, we estimate the number of unique properties per asset by using industry estimates of the average number of wells per property and Rystad's estimates of the average number of wells per asset. Dividing the two yields an estimate of properties per asset. The number of wells per lease is based on the total number of wells divided by the total number of leases, as reported by DrillingEdge.[5] Data for North Dakota is not available, so it is approximated using data from Montana, which also includes a portion of the Williston Basin.

Accelerated amortization of geological and geophysical expenses

Independent oil and gas producers can amortize geological and geophysical expenses over two years instead of recovering these costs through depletion, the standard way in which these types of intangible costs would be recovered.[3] We assume that 10% of exploration expenses in Rystad's UCube are due to geological and geophysical costs (the average percentage of U.S. exploration and development costs classified as geological and geophysical between 1999 and 2009, the most recent data available[6]) and that independent producers elect to amortize these costs over two years. Integrated operators instead recover these costs through standard cost depletion.

Domestic manufacturing deduction

Another form of support that we include in our analysis is the Domestic Production Activities deduction. This deduction was created to provide a benefit to manufacturing businesses that produce products in the United States. Businesses with income from "qualified production activities" in the United States can deduct a fraction of that income from their income tax responsibility. Most manufacturers are allowed to deduct 9% of their income from qualified production activities under this deduction; businesses in the oil and gas sector are allowed to deduct 6% of their income.[7]

Corporate tax exemption for Master limited partnerships (MLPs)

Operators organized as master limited partnerships, a corporate form open primarily to companies in the fossil fuel sector, can pass profits to partners with no corporate income tax while also being traded on highly liquid public securities markets. Although distributions are taxed at the partner level, the effective tax rate on MLPs is significantly lower than the combined corporate rate paid by standard subchapter C corporations plus the tax due on distributions to individuals. MLPs are particularly common amongst midstream pipeline companies that transport oil and gas.[8]

The lower effective tax rate for midstream companies could reduce the cost that producers pay to transport crude oil and natural gas via pipelines. We estimate the value of reduced pipeline transport costs by partitioning the U.S. Joint Committee on Taxation's[9] national estimate of foregone tax revenue from MLPs in the oil and gas sector specifically to MLPs that operate crude oil pipelines. We scale the national estimate by the percentage of energy MLPs associated with transportation[8] and averaged over all years for which estimates are available (2015–2019). Midstream MLPs transport both crude oil and natural gas, and thus we assign only a portion of the benefit of the MLP transport subsidy to crude oil pipelines. Our scaling is scaled based on the share of the U.S. intrastate trunk pipeline network dedicated to oil (45%) versus natural gas (55%).[10]

Royalty exemption for flaring and on-site use

There are instances in which operators are not required to pay royalties on gas that is produced at a well but lost or used before being sold. Here, we specifically quantify the benefits associated with royalty-free flaring of natural gas and use of natural gas to power equipment on well sites. We do not quantify on-site use of oil, because it is very small compared with on-site use of gas.

The Mineral Leasing Act of 1920[11] and the Outer Continental Shelf Lands Act of 1953[12] both state that royalties are due when oil or gas is removed or sold from the lease. The Department of the Interior and the courts have interpreted this as allowing oil and gas to be used royalty-free on a lease or agreement site to fuel production operations as long as eligibility requirements are met.[13] We assume that royalty structures on private or state lands are similar to those on federal lands, so royalties are not paid on gas production that is consumed or flared on-site.[14]

We calculate on-site use rates based on lease fuel use reported by EIA divided by gross natural gas production in Texas, North Dakota, and US offshore, respectively averaged from 2004 to 2013, the most recent year for which data were available. The rate of flaring in North Dakota is taken from Brandt et al.[15] The rate of flaring in the Permian Basin per barrel of oil production is calculated based on Permian casinghead gas production (the sum of casinghead gas from Texas Railroad Commission districts 7C, 8A, and 08[16] following the Texas RRC's basin designation[17]) as a percent of Texas total casinghead gas production multiplied by statewide venting and flaring figures from EIA.[18] US offshore flaring per barrel of oil production is estimated as total offshore flaring and venting divided by total offshore oil production, based on figures from the EIA.[19]

Note that we categorize this subsidy as one that reduces government revenue, even as in many cases it may actually be reducing revenue to private landowners to the extent they follow the royalty rates and practices of public landowners.

Texas crude oil severance tax exemptions

In addition to the federal support mechanisms, many states have tax policies that specifically benefit the oil and gas industry as well. Here, we quantify one measure that benefits crude oil producers in Texas, including those in the Permian Basin. The Texas tax code provides severance tax exemptions for oil wells that use anthropogenic carbon dioxide to perform enhanced oil recovery; that were previously deemed "inactive" (have not produced in more than one month in the previous 2-3 years); that are "low-producing" (less than 15 barrels of oil per day); or that are reactivated "orphaned" wells. The severance tax rate for wells that meet any one of these requirements is reduced by half from the standard rate of 4.6%, to 2.3%. The TX Comptroller estimates that nearly all wells claiming exemptions under these statutes will be enhanced oil recovery (EOR) wells by 2020.[20] Also, our analysis of new production is unlikely to include significant numbers of wells that were previously considered inactive. Thus, we focus on the subsidy to producers that employ EOR techniques. Note that these wells will also receive federal tax subsidies to their EOR operations, though the aggregate values for that subsidy were too small to include in our analysis. We estimate the volume of oil produced using EOR techniques in Texas using data from the National Energy Technology Laboratory.[21]

Quantifying subsidies that transfer liability or provide goods or services

Within industries for which there are large costs at the end of a facility's operating life (often also a period of operations when revenues are declining or gone), or for which accidents can cause damage well in excess of the assets deployed, liability problems are common. Extractive industries, including oil and gas, have both of these attributes. Well sites and pipelines have high closure and remediation costs. Accidents at well sites or during transportation or refining, though fairly low in probability, can generate large damages when they occur.

Governments have used a variety of strategies to address these structural challenges. Performance bonds may be required to ensure there are funds to clean a site at the end of its life are available despite low or no revenues from product sales at that part of the project life cycle. Insurance against particular types of operating risks may also be mandated. Industry-funded trust funds may be created to ensure money is available for rapid response to an accident or to cover residual clean-up costs. In both cases, the government normally seeks subsequent reimbursement from the responsible parties.

The economic case for these types of instruments is strong. For example, the requirement to purchase liability protection from an external party: (a) creates some price signal for these risks, and higher-risk operators should see higher premiums; (b) empowers another entity to review operations and flag potential safety problems, hopefully reducing the risk of an accident occurring in the process; and (c) establishes a pool of resources to compensate damaged parties, available even if the original company goes into bankruptcy.

This coverage can be expensive for operators, or in some cases may not be available at all. As a result, government interventions may reduce or remove the cost of this liability from the operator. Artificially low requirements for reclamation bonds or accident insurance mean that appropriate compensation will not be available for damages incurred by workers or the surrounding population. Policies that shift residual liability on to taxpayers are also common, a practice that has both a financial cost and also weakens the price signals to producers that otherwise would push them to invest in prudent risk-reduction activity.

We evaluate liability subsidies in two main areas. The first is where state or federal law sets required financial assurance levels below the expected value for damages or accidents. The second is where, even for the required level of coverage, there are government subsidies that artificially reduce either the cost to buy that coverage, or the quality of protection it provides. We evaluate specific liability transfers related to the oil and gas basins below.

Limited bonding for site closure and remediation

We quantify the level of support provided by measures that transfer liability to the public based on the cost of (inadequate) bonding or insurance. For example, if the known, eventual costs of well closure and remediation are higher than what oil producers are required to bond, the risk of the producers failing to adequately perform the cleanup is transferred to the public.[22] We quantify the subsidy as the difference in cost between the required bond and the foreseen, "actual" reclamation costs. For example, if well cleanup costs $100,000 per well, but producers only bond for $1,000 per well (these are indicative figures), the subsidy would be equivalent to the cost of bonding for the difference. (Assumptions regarding required bonding level, actual costs, and bond premiums are detailed in Supplementary Table 2.)

Supplementary Table 2. Approach to quantifying inadequate bonding for site closure and reclamation

Jurisdiction	Bonding level required by regulation	Assumed actual reclamation costs	Cost of bonding (as premiums)
Texas	Producers may bond individual wells for $2 per foot of well depth, or obtain blanket bonds for $25,000 (1 to 10 wells), $50,000 (11 to 99 wells), or $250,000 (100+ wells).[23] We assume that producers elect blanket bonding and that the average bonding amount is equivalent to 0.01% of the average well cost (at average cost of $7.5 million,[24] equivalent to $750 per well).	We assume reclamation costs average 1.33% of well cost, based on actual costs of about $10/ft of depth[25], 10,000 ft depths, and average well cost of $7.5 million.[24]	We assume annual premiums on surety bonds for onshore projects average 3% of the face value of the bond.[26]
North Dakota	Producers may bond individual wells for $50,000 or up to six wells for $100,000.[27] We assume that producers elect this latter blanket bonding and that the average bonding amount is equivalent to 0.3% of the average well cost (at average cost of $7.5 million,[24] equivalent to $22,500 per well).		
Federal offshore	BOEM requires general bonds and, depending on the financial status of the leaseholder, also a "supplemental bond" to ensure that site closure and reclamation requirements are met. For general bonds, BOEM requires a lease-specific bond in the amount of $500,000 or a company area-wide bond of $3 million.[i] We adopt the conservative assumption that each operator adopts a lease-specific bond. In reality, operators would likely establish area-wide bonds or cover new wells under existing area-wide bonds, or both. For supplemental bonds (which we assume apply only to non-integrated producers), it varies on a case-by-case basis:[28] in 2008 it averaged $1.24 million per lease.[29]	We assume reclamation costs average 10% of the costs of the platform.[30,ii]	We assume annual premiums on surety bonds for offshore projects also average 3% of the face value of the bond.[29]

[i] Per https://www.boem.gov/uploadedFiles/BOEM/BOEM_Newsroom/Speeches/2013/RMMLF-Presentation-Williams-20130123.pdf (Accessed 14 August, 2017)

[ii] This is roughly consistent with expected decommissioning costs of offshore oil platforms in the UK, averaging £81 million or $115 million per installation.[31] For a detailed treatment, see Kaiser and Pulsipher.[32]

The U.S. Bureau of Ocean Energy Management charges bonding fees specifically to cover plugging and abandonment costs in the event that an operator is bankrupt and unable to pay reclamation costs.[29] We assume that large operators have greater financial resources with which to pay site closure costs and are less likely to fall into bankruptcy than smaller firms. Because we assume their reclamation obligation will be paid, we do not ascribe this subsidy to integrated operators. (We use an operator's status as integrated or independent as a proxy for size, recognizing that some independent operators, such as ConocoPhillips, can be quite large.) This is likely to be a conservative assumption: very large firms in the coal industry, for example, *have* entered bankruptcy, shifting billions in reclamation liabilities to taxpayers.

Transferring rail safety risks to the public

Oil spills or other accidents can occur during oil transportation to markets, but may not be adequately insured. We include the costs associated with this transfer of liability as a support measure here, since any underpricing of liability for oil transport could affect the price producers receive and therefore be an indirect form of support to new investment.

We quantify two such measures of support. The first is inadequate safety standards on oil tank cars (commonly used to transport oil from North Dakota) that, though recently made more stringent than prior requirements, remain below those recommended by the National Transportation Safety Board (NTSB).[33] The estimated added cost of NTSB's recommended regulations, compared with those recently put in place, is $2.0 billion over the decade-long phase-in.[34] Averaging those costs over a period from 2014 to 2024, and based on an estimated 5.8 billion barrels of oil travelling by rail during that period, results in an estimate of $0.35 per barrel (based on Exhibit 5-3, Exhibit 4-4, and Exhibit 4-7 in a study by ICF for the American Petroleum Institute.[34]) This is interpreted as the residual liability borne by the public instead of by the rail car owners. (Note that additional liability may be borne by the public in the near term, as the older, DOT-111 and CPC-1232 cars are retrofit or replaced, though we do not quantify that here.) Compared with legacy "DOT-111" tank cars, the new standards require tank cars with thicker steel, insulation, and shields at each end of the car. Still, even newer cars with some of these attributes have been involved in accidents involving crude oil derailments and spills. For example, tank cars involved in accidents in Mosier, OR in 2016[35] and Lynchburg, VA in 2014[36] were newer, CPC-1232 cars.

The other measure of support is inadequate insurance coverage for major accidents involving oil-carrying trains, since this also reduces industry costs and transfers risk to the public.[37] Here, we take a similar approach as for offshore oil spills, since the damages from an oil-train accident can also extend to many billions of dollars.[38] We characterize the level of support as the shortfall in insurance coverage relative to the maximum level available in the marketplace – though recognize that the available cover may still be less than what is needed to fully internalize the liability.

Major, "Class I" railroads such as BNSF and Union Pacific already carry the maximum amount of liability insurance currently available, about $1.5 billion, and so we do not consider any further shifts in liability from these carriers (but for the differential in tank car standards captured above). In contrast, smaller railroads often haul oil though carrying much less insurance coverage. Coverage for Class II (regional) railroads does not generally exceed about $200 million, for example. Coverage for Class III (local) railroads typically does not exceed $100 million,[39] and can be much lower. For example, the July 2013 crude oil train explosion in Lac-Megantic, Quebec involved a Class II railroad with only $25 million in liability insurance. Costs of $2 billion or more will likely be shifted to the public.[40]

There are at least four local and regional railroads operating in North Dakota that carry crude oil. These are three regional railroads: Dakota, Missouri Valley, and Western (DMVW); Northern Plains Railroad (NPR); and Red River Valley and Western Railroad; and the local railroad Yellowstone Valley Railroad. Increasing the coverage held by these railroads to the maximum available of $1.5 billion, at premiums of $25 per $1,000 of coverage,[39] would cost an estimated $130 million annually, or about $0.18 per barrel of North Dakota oil production. This is a conservative figure, since the premium used here, $25 per $1,000, is based on the cost of insuring Class I railroads,[39] which we expect would garner lower premiums both due to their size and to better risk management than the smaller Class II or III railroads. It is possible that premiums could decrease with the introduction of the safer rail cars, also modeled here. We cannot know whether this potential to over-estimate insurance rates is enough to counteract the likely underestimation we introduce by applying the conservative rate of $25 per $1,000 of coverage from Class I railroads to the Class II and III railroads modeled here. Crude by rail is less common in Texas, so we do not quantify inadequate insurance there.

Limits to insurance coverage for oil spills and accidents

Similarly, if producers are not adequately insuring for potential oil spills at wells, risk may be transferred to the public. For onshore oil wells, we assume that the cost of any spills are already adequately covered by the existing Oil Spill Liability Trust Fund (OSLTF), to which producers contribute by paying a per-barrel fee.

Oil spills at offshore wells can lead to damages of billions of dollars. The Deepwater Horizon accident, for example, triggered damages of at least $10 billion.[41] However, that level of insurance is not available in the marketplace. Following Murchison,[42] we therefore quantify the subsidy by assuming offshore producers be required to demonstrate insurance at the maximum amount of insurance *available*, which has been estimated at $1.5 billion,[41] and as detailed in Supplementary Table 3. Because actual damages (as with Deepwater Horizon) can be many times higher than $1.5 billion, quantifying subsidies based on available insurance coverage rather than actual risk will underestimate subsidy values. Other approaches to provide insurance in excess of $1.5 billion do exist, such as the approach used in the nuclear industry to provide up to roughly $10 billion in coverage under the Price-Anderson act.[43] Such approaches have not been applied in the U.S. oil industry, however, and we do not assess the costs to the oil industry of such approaches here. Larger operators may be able to provide additional compensation for damages from corporate funds and remain solvent. Through 2013, for example, BP paid more than $4 billion in criminal and civil fines associated with the incident,[44] and more fines have since been agreed to and paid. Thus, we do not estimate incremental bond premiums needed to bring up liability coverage for the integrated operators, though do incorporate it for the smaller firms that may be less able to cover high damage costs associated with an oil spill.

Supplementary Table 3. Approach to quantifying inadequate insurance for oil spills

Jurisdiction	Financial assurance required for oil spill removal costs	Limit of liability for damages	Assumed "actual" removal and damage costs	Insurance premiums
Onshore	None	$634 million[45]	We assume that "actual" removal and damages costs, less what the insured entity pays towards cleanup, can be covered by the Oil Spill Liability Trust Fund	None: assumed covered by the entity and the Oil Spill Liability Trust Fund (OSLTF).
Federal offshore	Up to $150 million for each covered facility	$134 million for each covered facility	$1.5 billion, limited here to the estimated amount of insurance available,[41] following Murchison[42]	0.1%,[46] with balance of damages covered by Oil Spill Liability Trust Fund or other sources paid from the first year of production until 2 years after production ceases

Public financing of the U.S. Strategic Petroleum Reserve

The U.S. federal government provides public funds to finance the Strategic Petroleum Reserve (SPR), a system of bulk petroleum storage facilities. These facilities provide benefits to oil producers, as the system is occasionally used as a "bank" from which producers can draw to maintain a steady stream of petroleum to other parts of the supply chain.[47] The SPR also provides benefits to both consumers and producers by somewhat buffering price shocks. SPR is fully funded by taxpayers, though stockpiles in other IEA countries are often funded in part or total by consumers and firms.

Following the OECD,[48] we take as our estimate of the value of this subsidy the U.S. Department of Energy's funding for the SPR from 2003 to 2016, all years for which the Department of Energy provides publically-available budget justifications.[49] The average subsidy estimate for this period is assumed to hold in future years (in real terms), though we note that the U.S. Department of Energy is considering upgrades to the SPR that may increase costs. The subsidy amount per unit of production is determined by dividing by U.S. crude production projections during the same period.[19] This yields a price of $0.07 per barrel in 2016 increasing (in nominal terms, assuming 2.5% annual inflation) to $0.09 nominal per barrel in 2040. Half of this subsidy is assigned to producers, as the benefits of the SPR are also shared by consumers who are protected from oil price shocks.

SPR is effectively a state-owned enterprise, and the valuation method adopted by OECD in recent years picks up cash flow support, not the overall level of support to the enterprise akin to what a private provider would incur to provide similar stockpiling services. A more accurate costing approach (and more similar to the methodology OECD applied in years past)[50] would estimate annualized cost of operations, including cost of capital for infrastructure, liability insurance, financing costs for working capital tied up as oil inventory, and a return on investment for the billions of dollars invested in the stockpiling scheme. This more systematic approach will generate higher subsidy estimates; we view usage of the cash flow funding approach as conservative and likely to understate actual subsidy levels.

Public coverage of road damage and costs

State and local governments build and maintain roads used by the oil and gas industry when constructing and operating wells. Though these roads are not used exclusively by oil and gas vehicles, the damages caused to these roads (and therefore costs) can, in some cases, be directly related to increased truck traffic to and from oil and gas wells.[51] This results from three main factors: extremely heavy weights for vehicles used in this sector versus regular traffic; many trips to support particular well sites; and significant travel on secondary roads which were not designed for either the vehicle weight or number of trips for which they are now used. For example, the Texas Department of Transportation has estimated that annual road maintenance costs are $2 billion higher on state roads because of oil and gas development (only a fraction of which is covered by existing fees), and have been considering approaches to recovering these costs from (or transferring liability back to) the oil and gas industry.[52]

Building on approaches and findings in Texas, we estimate the cost of increased road maintenance in North Dakota borne by the public as the difference between the added cost of road maintenance due to oil truck traffic and the current overweight fees paid by these trucks (Supplementary Table 3).

Supplementary Table 3. Approach to quantifying inadequate compensation for road damages

Jurisdiction	Marginal cost of road maintenance and restoration due to oil industry	Existing surcharges
Texas	Estimated as averaging $28,000 per year over lifetime of each well[53]	Current overweight fees from all trucks total about $111 million statewide annually.[54] Assume half of these are from oil and gas industry trucks (given lack of better information) implies contribution of $55 million annually, or about 3% of $2 billion total annual state road maintenance shortfall.[52]
North Dakota	Assumed same as above[i]	Assumed 3% of the marginal cost of road maintenance is collected as fees, same as above[ii]

[i] Unlike in Texas, a detailed model of road damages was not available for North Dakota. For comparison, North Dakota's road budget increased by about $760 million per year (https://www.nmlegis.gov/lcs/handouts/TRANS%20080614%20Item%203%20North%20Dakota%20Highway%20Funding.pdf [Accessed 14 August, 2017]) over a time (between 2007 and 2015) when 9,000 new oil wells (net) were brought online.[55] Though not all of these new costs may be associated with new oil wells, the figure equates to an increase in average annual maintenance cost equivalent to about $84,000 per new well.

[ii] Overweight fees from all trucks in North Dakota increased $5 million[56] at a time when 3,500 new wells were brought online.[55] This equates to about $1,400 per well, a small fraction of the increase in average annual maintenance.

Tax incentives not included in this analysis

Our analysis excludes some types of tax incentives. Two of these have fairly large values in earlier studies. Our reasons for excluding them here are described below.

- **Deep Water Royalty Relief Act,** The Deep Water Royalty Relief Act, passed in 1995, exempts certain deep water oil wells in the Gulf of Mexico from royalty payment.[57] The loss in tax revenue from this royalty exemption could be billions of dollars over the approximately 25-year lifetime of these wells.[58] However, the amount of tax revenue that would be collected from wells exempt under the DWRRA is highly dependent on future production and oil prices. Further, our analysis focuses on new production, which is not exempted from these payments.

- **Last-in first-out accounting for fossil fuel companies.** Last-in first-out (LIFO) accounting is allowed by the U.S. tax code, but is not used in any other country. Under LIFO accounting, companies can calculate the value of inventory based on the most recent cost of products purchased and added to that inventory. In contrast, under first-in first-out (FIFO) accounting, items in inventory are valued at the actual nominal price paid for those items. If a company inventories goods at a low price and then later sells those goods at a higher price, the resulting profit would not be considered taxable income under a FIFO system. The difference in inventory valuation between the LIFO and FIFO accounting method is called the "LIFO reserve." Although all sectors can benefit from this tax treatment, energy companies accounted for about 37% of this LIFO reserve in 2010.[59] In turn, a single firm (ExxonMobil), accounted for 67% of the energy industry's LIFO reserve. Production decisions in individual basins are unlikely to be affected by LIFO accounting, which is a general economic subsidy that affects operators' overall finances. Benefits of LIFO accounting are highly dependent on present and future oil price, and are not dependent on basin-specific production. It is most valuable during times of fast-rising prices for a firm's production; during periods of declining or stable production and prices, its impact declines.

Analysis of interaction between subsidies and oil price

Our analysis considers which U.S. oil fields are dependent on subsidies at US$ 50 per barrel, and includes a sensitivity analysis for prices between US$ 30 and US$ 100 per barrel (Figure 3 in the main manuscript). There are also interactions between the subsidies themselves and the price of oil. Should the subsidies analysed in our study be removed, U.S. oil production would decrease relative to the case with subsidies. This decrease in supply would, in turn, lead to increases in global oil prices. Using a simple, microeconomic model of the world oil market,[60] we estimate that subsidy removal would increase global oil prices by about $1 per barrel.

This level of price increase assumes an elasticity of supply of 0.87, as calculated from a cumulative oil supply curve from Rystad Energy at $50 per barrel,[1] and an elasticity of oil demand of -0.2.[61] It further assumes that the cumulative reduction in U.S. supply of 16.5 billion barrels of subsidy-dependent oil (Table 2 of main manuscript) will occur over the next two decades, representing just over 2% of the 700 billion barrels of global crude oil production over that time period.[62]

An increase in global oil price of $1 per barrel – e.g. from US$ 50 to US$ 51 per barrel – would not have major impacts on our findings. We estimate it would increase the total economic (but not yet discovered) oil resources in the U.S. by about 0.8 billion barrels, while decreasing the oil resources dependent on subsidies by about 0.6 billion barrels. This would decrease the overaell fraction of subsidy-dependent resources from 47% (Table 2 in main manuscript) to about 44%.

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