

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

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**Countries in the G20 have committed to phase out 'inefficient' fossil fuel subsidies. However, there remains a limited understanding of how subsidy removal would affect fossil fuel investment returns and production, particularly for subsidies to producers. Here, we assess the impact of major federal and state subsidies on US crude oil producers. We find that, at recent oil prices of US\$50 per barrel, tax preferences and other subsidies push nearly half of new, yet-to-be-developed oil investments into profitability, potentially increasing US oil production by 17 billion barrels over the next few decades. This oil, equivalent to 6 billion tonnes of CO<sub>2</sub>, could make up as much as 20% of US oil production through 2050 under a carbon budget aimed at limiting warming to 2 °C. Our findings show that removal of tax incentives and other fossil fuel support policies could both fulfil G20 commitments and yield climate benefits.**

In 2009, twenty major world economies, including China, India, the European Union and the US, committed to phase out inefficient fossil fuel subsidies. The rationale for removing these subsidies was that they 'encourage wasteful consumption, distort markets, impede investment in clean energy sources and undermine efforts to deal with climate change'<sup>1</sup>. In recent years, plans have advanced, and some countries have now specified which measures they consider subsidies and when they intend to remove them. For example, the Obama Administration in the US listed 16 federal measures that total at least US\$4 billion per year in tax expenditures alone<sup>2</sup>, committing (with other G7 countries) to eliminate them by 2025<sup>3</sup>.

Broadly speaking, fossil fuel subsidies are designed to provide a stimulus to either consumption or production of fossil fuels. Subsidies that support consumption pay a portion of the consumers' cost of fossil-based energy through one of several mechanisms, including direct rebates<sup>4</sup>. Governments often put in place these consumer subsidies to aid in energy access or availability. By contrast, subsidies to fossil fuel producers are intended to support infrastructure investment or resource extraction, often through tax deductions or by shifting financial or environmental risks of fossil fuel development projects from investors to the government<sup>4,5</sup>.

How subsidies to consumers affect energy decision-making is relatively well studied, in part because these subsidies have comparatively clear impacts on price, making them more straightforward to assess using economic models and empirical approaches<sup>6–10</sup>.

The impact of subsidies to fossil fuel producers on decision-making is much less well understood, largely because it can be difficult to assess how subsidy value influences how much individual firms produce. In theory, producer subsidies enable firms to drill new wells and expand production to some more 'optimum' amount<sup>11</sup>. Several analysts, however, assert that the vast majority of subsidy value goes to fossil fuel projects that are already expected to be profitable and would be developed anyway<sup>9,12,13</sup>. In such cases, subsidy value goes directly to profits, with very little impact on production. Efforts to understand how much subsidy value goes to extra profits versus new investments are continuously challenged by a persistent information asymmetry, where firms know more about their project costs than do analysts or policymakers<sup>5,11</sup>.

A better understanding of how subsidies affect the economic returns of specific fossil fuel producers offers at least two important benefits. First, it could clarify how firms use subsidy revenue, whether for added profits or for increasing capital investments. This could help governments compare alternative uses of limited public funds available for subsidies. Second, and the focus of this study, is how subsidies distort markets to increase fossil fuel production<sup>14</sup>. This issue is of concern given the world's commitment to limit warming to 'well below 2 degrees C'<sup>15</sup>, and the corresponding realization that attaining this goal requires leaving most fossil fuel reserves undeveloped<sup>16</sup>. Should production subsidies increase fossil fuel development, they could, in the words of the G20 country leaders, 'undermine efforts to deal with climate change'<sup>1</sup>.

Here, we conduct a detailed analysis of the economics of subsidies on all discovered, but not-yet-developed, crude oil fields in the US. We chose the US as our case study because it is the world's largest fossil fuel producer<sup>17</sup>, offers substantial subsidies for fossil fuel production<sup>18</sup> and has committed to phase out these subsidies<sup>2</sup>. We find that, at recent US oil prices of US\$50 per barrel, tax preferences and other subsidies push nearly half of new, yet-to-be-developed oil into profitability. This potentially increases US oil production by almost 17 billion barrels over the next few decades, equivalent to 6 billion tonnes (Gt) of CO<sub>2</sub>. Our analysis suggests that oil resources may be much more dependent on subsidies than previously thought, at least at prices near US\$50 per barrel. The findings highlight an inconsistency between commitments to ambitious national and international goals to reduce CO<sub>2</sub> emissions and subsidies to the fuels that generate those emissions. The methods used here could be more widely applied to other countries and to other fossil fuels.

## Oil regions and subsidies examined

The US provides subsidies to all fossil fuels, but we focus here on oil because it receives about twice the level of support in aggregate as coal in the US<sup>18</sup> and, although it is subsidized slightly less than gas (in aggregate), oil is 30% more carbon-intensive<sup>19</sup> and therefore its global production must begin declining sooner if the 2-degree goal is to be met<sup>16</sup>. We examine all crude oil fields in the US that have been discovered but not yet developed—that is, that were not yet producing as of mid-2016.

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**Table 1 | List of subsidies included in this study**

Category	Subsidy	Abbreviated subsidy name (for Fig. 2, where applicable)	Description
Forgone government revenue	Expensing of intangible exploration and development cost	IDC	Allows oil producers to deduct many drilling and field development costs associated with domestic oil wells that for other industries would be capitalized
	Excess of percentage over cost depletion	Pct. depl.	Allows selected producers to deduct a portion of the gross value of their production rather than standard deduction rules that limit deductions to invested capital
	Domestic manufacturing deduction	Mfr. deduct.	Enables manufacturers to deduct a percentage of 'gross income' from taxable income
	Accelerated amortization of geological and geophysical expenses	Geo & Geo	Allows independent producers to amortize geological and geophysical expenses over two years rather than the producing life of a well
	Corporate tax exemption for master limited partnerships	MLP	Enables firms to avoid corporate income taxes, a special allowance available predominantly to the fossil fuel industry
	Royalty exemption for flaring and on-site use	Free flare	Operators are not required to pay royalties on gas production that is flared or consumed on-site (for example, to power equipment). This is a subsidy that applies on federal lands, and because state and private landowners often follow federal royalty practices, we also apply it to all landowner types.
	Texas crude oil severance tax exemptions	Texas EOR	Standard Texas severance tax rate is reduced for oil wells in Texas considered "high-cost", that have been inactive for several years or use enhanced oil recovery (EOR). This subsidy applies only to Texas in our analysis.
Transfer of liability to the government	Limited bonding for site closure and reclamation	Ltd bonding	Jurisdictions routinely allow producers to provide assurance (for example, via bonding) for less than the actual known costs of closure and reclamation of oil wells, transferring risk to the public <sup>21,22</sup> . We quantify this subsidy only to Texas, North Dakota and federal offshore oil fields.
	Transferring rail safety risks to public	Rail risks	Safety standards for rail cars used to carry oil remain below the National Transportation Safety Board's recommendations, transferring risk to the public. We apply this federal subsidy only to fields in North Dakota due to that state's relative dependence on rail transport.
	Limits to insurance coverage for oil spills or accidents	Spill insur.	Federal government requires proof of insurance to cover oil spill 'removal' but not for full extent of damages, thereby transferring risk to the public since other clean-up mechanisms (for example, Oil Spill Liability Trust Fund) are inadequate, under-pricing this risk to producers.
Below-market government provision of goods and services	Public financing of the US Strategic Petroleum Reserve	SPR	The US Strategic Petroleum Reserve is maintained using federal tax revenue to fund infrastructure that provides hedging and borrowing capacity for private industry.
	Public coverage of road damage costs	Road maint.	Increased costs of maintenance and restoration of state and local roads due to very heavy loads associated with oil and gas activities that are not fully covered by fees on users. We quantify this subsidy only in Texas and North Dakota, due to data availability.

Subsidies include those that forgo government revenue, transfer liability or provide services at below-market rates.

We divide the fields into four groups. Three of these groups represent the largest oil basins (in terms of remaining crude oil resources) in the US: the Permian Basin, the Williston Basin, and offshore, federally administered fields in the Gulf of Mexico. The Permian and Williston basins rely heavily on horizontal drilling and hydraulic fracturing, and are dominated by smaller producers that are best able to access federal tax preferences directed at non-integrated producers<sup>20</sup>. By contrast, larger integrated producers (such as BP, Chevron and Shell) dominate the large offshore deposits in federal waters in the Gulf of Mexico, with projects that require relatively long lead times and large amounts of capital, and for which fewer subsidies to new production are currently available. All other basins comprise a fourth group in our analysis. That group includes conventional onshore oil deposits such as those found in California's San Joaquin Valley and Alaska's North Slope; oil shale in

Utah's Uinta Basin; and other shale oil, such as Wyoming's Powder River Basin or Oklahoma's Anadarko Basin.

We focus on three categories of subsidies: forgone government revenue (especially taxes), transfer of liability to the government<sup>21,22</sup> and below-market government provision of goods or services (Table 1). These types of support all confer a financial benefit from government to oil producers, and for this reason are widely recognized as subsidies, including by the World Trade Organization<sup>23</sup>. Table 1 lists the dozen subsidies we consider; unless otherwise noted, the federal government provides each measure. Each is described in greater detail (including how quantified) in the Supplementary Methods.

### Effect of subsidies on project economics

For each of the subsidies in Table 1, we assess how the measures affect the return on investment—or internal rate of return (IRR)—to

new US oil resources for each of the more than 800 fields that have been discovered but not yet developed.

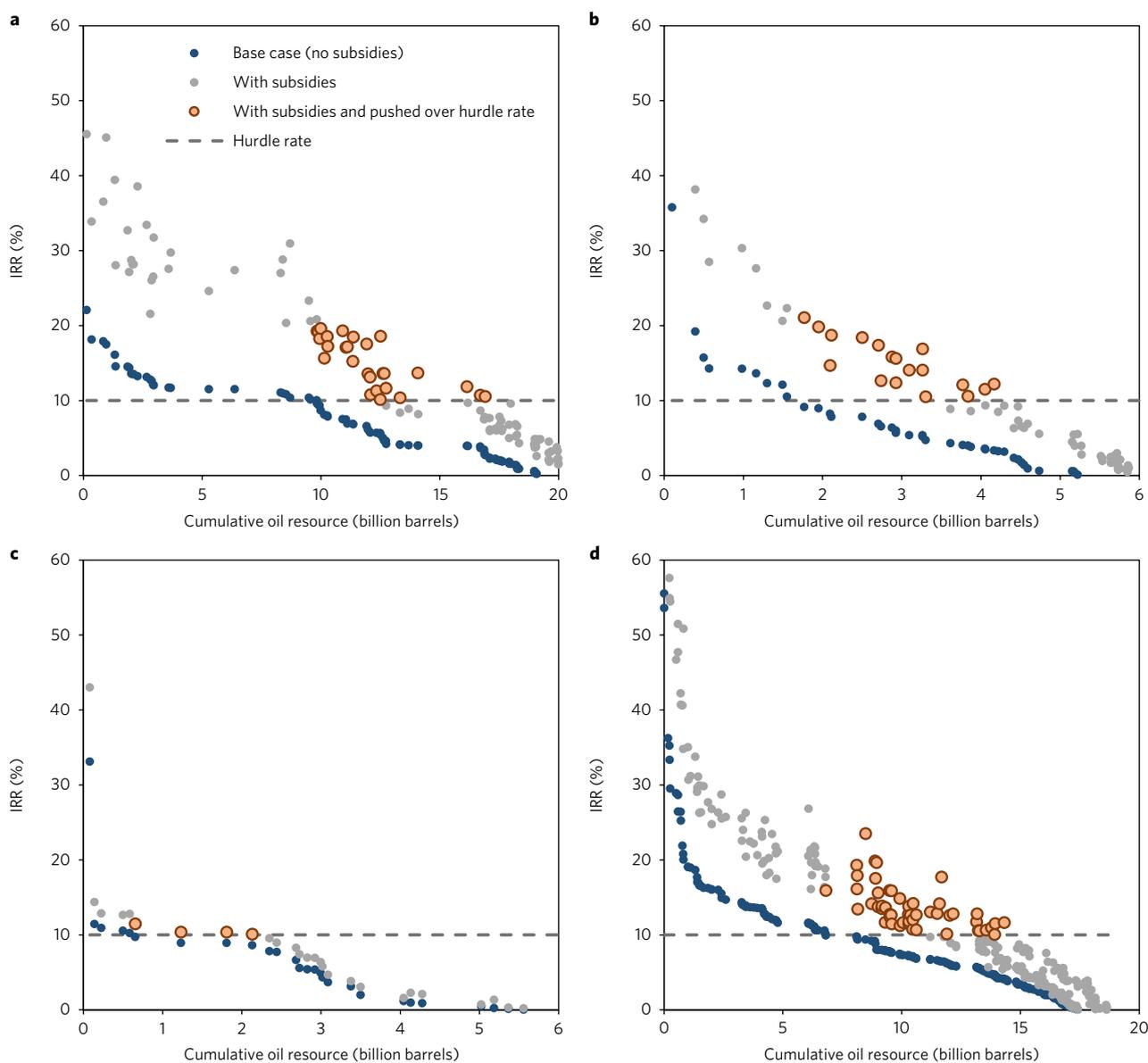
We build our analysis from detailed field-level cash flow and production data maintained by the oil industry consultancy firm Rystad Energy. Using these estimates as a starting point, we modify the appropriate portion of cash flow to isolate the effect of individual subsidies, evaluating each against a ‘no subsidy’ case.

For example, the US tax code normally requires firms to recover capital expenses over the service life of the asset, either through depreciation or, for mineral properties, using a provision of the US tax code called ‘cost depletion’. However, for some oil and gas producers, a federal tax incentive allows firms to immediately deduct some or all ‘intangible drilling costs’ (IDCs) from their income

for tax purposes. This increases tax deductions in the early years of operation compared with standard cost recovery, deferring tax liability and increasing investor return on a present-value basis. As a result, the IRR is higher in the case with subsidies than in the one without, and the difference in IRR reflects the value of the subsidy<sup>24</sup>.

We assume a minimum return needed for a project to proceed (the investor hurdle rate) of 10% (nominal). This threshold value is commonly used by investors<sup>25</sup> and also by Rystad Energy<sup>26</sup>. In practice, investor hurdle rates may vary depending on risk expectations and financing strategies.

Across all US oil fields considered, we find that subsidies increase the IRR of oil projects by a median of 3 percentage points, with a range of 2–6 percentage points (representing the 25<sup>th</sup> and 75<sup>th</sup> percentiles). Figure 1 shows the effect of this subsidy-induced bump in



**Fig. 1 | Effect of subsidies on new project economics at US\$50 per barrel. a–d,** Charts showing the starting (before subsidy) and ending (after subsidy) IRR for the projects analysed in the Permian Basin, Texas (**a**), the Williston Basin, North Dakota (**b**), the Gulf of Mexico (offshore) (**c**) and the rest of the US (**d**). Each project is displayed as a single dot, ordered from the highest starting IRR on the left to the lowest starting IRR on the right. The effect on IRR can be seen as the distance between each blue (darker) and grey (lighter) pair of dots. (Each matched pair of dots refers to the same oil field.) Projects that never reach a positive IRR (even with subsidies) are not shown. Those projects tend to have a smaller increase in IRR from subsidies, which explains why the median increase of 3 points is smaller than what one might infer from these figures alone.

project returns across the hundreds of fields assessed, divided across the four regions considered.

Whether this subsidy-driven boost to IRR affects a project's investment decision depends on whether the subsidies tip the project from being uneconomic to economic, by crossing the hurdle rate (shown as a grey, dashed horizontal line in Fig. 1). At prices of US\$50 per barrel, subsidies push enough projects above the 10% hurdle rate to bring roughly 17 billion barrels of additional oil online. Much of this occurs in Texas's Permian Basin. As shown in Fig. 1a, about 10 billion barrels of Permian oil are in fields that would be profitable at US\$50 per barrel even without subsidies, but subsidies bring on enough extra fields to produce an additional 6.5 billion barrels of oil. In this region, about 40% of the economic oil resource is subsidy-dependent.

The subsidies that have the greatest impact on this outcome are the immediate expensing of IDCs, the percentage depletion allowance and the domestic manufacturer's deduction (Fig. 2).

Figure 1b,d shows a similar pattern of subsidy impacts for the Williston Basin and the rest of the (onshore) US as for the Permian. Figure 1c for offshore oil in the Gulf of Mexico differs. For these high-cost offshore projects, the fraction of fields that are economically attractive (even with subsidies) at US\$50 per barrel is much smaller. The subsidy bump is also smaller, since fewer producers qualify for the independent status that comes with some of the most generous subsidies.

The impact of subsidies is highly sensitive to oil price (Fig. 3), which could have important policy implications. At very low oil prices (for example, US\$30 per barrel), almost no new (discovered but not yet producing) fields would be developed, even with subsidies. In this case, expected revenues do not cover project costs plus the 10% return needed to justify taking on the project risk, and the projects do not proceed. By contrast, at US\$100 per barrel, revenues are sufficient that almost all projects would go ahead anyway, with no need for subsidies; in such a case, nearly all of the subsidy value would go to extra profits.

Figure 3 also displays the sensitivity to the hurdle rate chosen. Although our central case (as in Fig. 3a) uses a 10% hurdle rate, other oil-industry analysts<sup>27,28</sup> have used a hurdle rate of 15%. At that rate (Fig. 3b), 19 billion barrels of oil (instead of 17) would be subsidy-dependent at US\$50 per barrel, and only 4 billion (instead of 19) would proceed anyway.

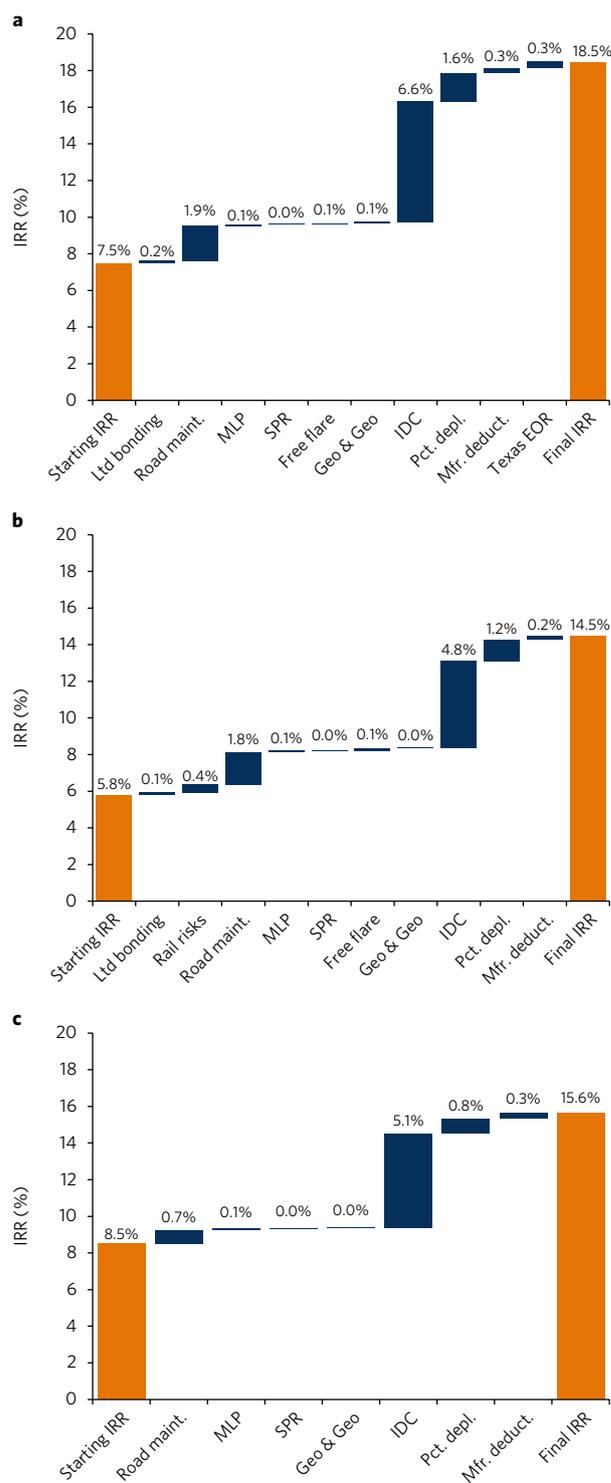
There are also interactions between subsidies themselves and the price of oil that are not included in the calculations above. For example, we estimate that the removal of US subsidies would lead global crude oil prices to rise by about US\$1 per barrel, assuming a starting global price of approximately US\$50 per barrel as in our central case (see the Analysis of interaction between subsidies and oil price section in the Supplementary Methods). This increase would not have a substantial effect on our findings: some additional oil fields would be profitable (containing an estimated 1 billion barrels), reducing the proportion of fields depending on subsidies from 47% (Table 2) to about 44%.

### Effect on oil production and industry profits

At prices of US\$50 per barrel, subsidies boost into profitability fields that contain an estimated 17 billion barrels of oil (as shown in Fig. 3), which would release about 6 GtCO<sub>2</sub> once burned, assuming standard carbon contents (and discounting for non-energy uses), as described in the Methods. Table 2 presents the scale of subsidy-dependent oil by basin, both in terms of barrels and as a share of each basin's resource base.

In addition, Table 2 also shows that the gas extracted as a co-product of this subsidy-dependent oil—totalling about 20% (in energy terms) of the crude—would release about 1 GtCO<sub>2</sub>.

Some context on the relative scale of these CO<sub>2</sub> emissions is helpful. The Intergovernmental Panel on Climate Change (IPCC)



**Fig. 2 | Average effect of each subsidy at US\$50 per barrel. a–c,** For each subsidy provided in the Permian Basin, Texas (**a**), the Williston Basin, North Dakota (**b**) and the rest of the onshore US (**c**), these charts show the production-weighted average increase in project IRR across all fields analysed. Average starting and ending IRRs are displayed as orange bars; blue bars indicate the effect of each subsidy, listed using abbreviations defined in Table 1. Subsidies are listed in the order analysed, as described in the Methods. In each area, IDC is the largest subsidy, including in the Gulf of Mexico (not shown). Very few projects for offshore Gulf of Mexico are economic at an oil price of US \$50 per barrel, and the effect of subsidies is both small in IRR terms and highly variable. As a result, we do not include a similar chart for that region here.

has estimated that if society is going to maintain a two-thirds chance of limiting warming to the internationally agreed goal of 2 °C<sup>29</sup>, net global CO<sub>2</sub> emissions from 2012 to 2100 cannot exceed 990 GtCO<sub>2</sub><sup>30</sup>. Adjusting for the 150 GtCO<sub>2</sub> released since 2012<sup>31</sup>, emissions from 2016 onward cannot exceed 840 GtCO<sub>2</sub>. In that

context, continued subsidies for oil investment could produce oil (and associated gas) that, once burned, will yield CO<sub>2</sub> emissions equivalent to nearly 1% of the remaining global carbon budget for all sectors of all economies.

Carbon budgets for individual countries are rarely defined, either for fossil fuel consumption or, as assessed here, fossil fuel production. Some researchers have explored this question using models that minimize the cost of meeting a global budget<sup>16,32</sup>. In these models, fossil fuel production each year is based on the costs of producing each fuel. Countries that can produce at lower cost produce a greater fraction of the total.

These models suggest a cumulative carbon budget for US oil production between 2016 and 2050 of 30 to 45 Gt CO<sub>2</sub><sup>16,32</sup>. This range—which represents CO<sub>2</sub> emissions from combusting US-produced oil—could also be lower, since it does not consider that the US is a country with high relative wealth and a high proportion of historical fossil fuel extraction, and so may be expected to produce a relatively smaller portion of fossil fuels needed under a low-carbon pathway<sup>33</sup>. Regardless, from a carbon budget perspective, subsidies may be responsible for up to 20% (6 Gt of 30–45 GtCO<sub>2</sub>) of the US share of oil production through 2050 under a cost-efficient approach to limiting warming to 2 °C.

When subsidies instead flow to fields that would proceed anyway, they represent a transfer payment from taxpayers to company profits. At the price of US\$50 per barrel, we find that a bit more than half (53%) of subsidy value (in net present value terms) goes to projects that would have proceeded anyway. That fraction rises to nearly all (98%) of subsidy value at US\$100 per barrel. As others have found<sup>13,28</sup>, regardless of the oil price, the majority of taxpayer resources provided to the industry end up as company profits.

**Discussion**

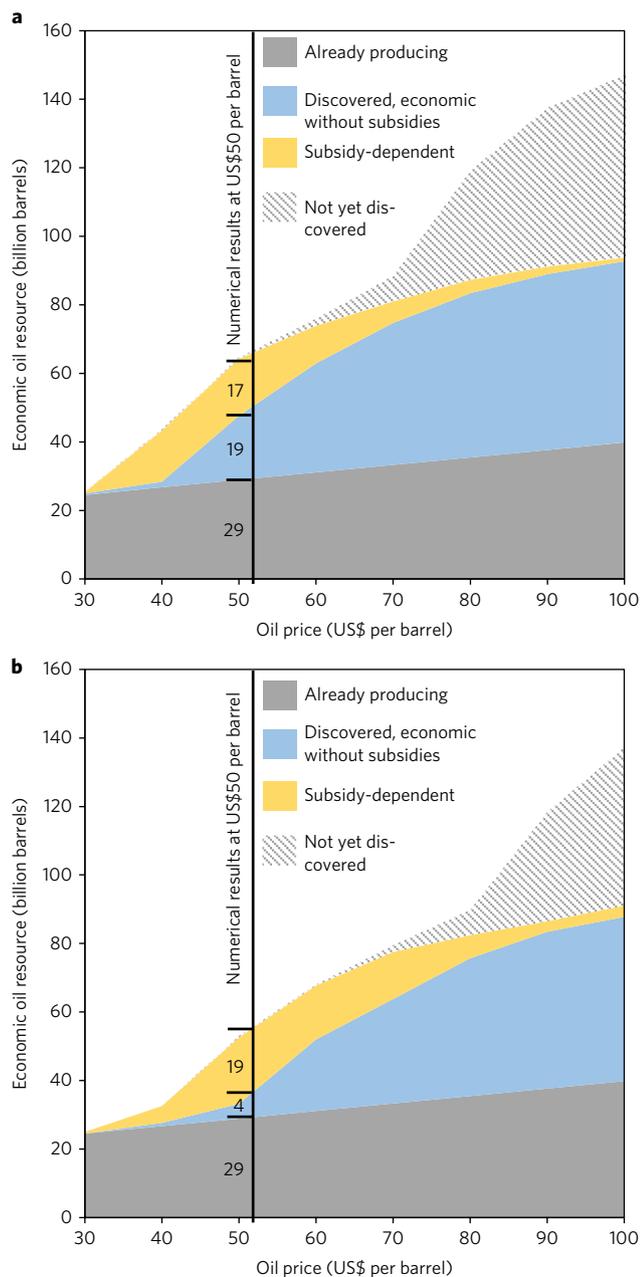
The US has committed to phasing out inefficient fossil fuel subsidies in three international forums: the G20, APEC and the G7<sup>2</sup>. Federal tax subsidies to the oil and gas industry alone cost US taxpayers at least US\$2 billion each year (and would cost more if oil prices rise)<sup>2,18,34</sup>. The limited number of academic studies to date have suggested that subsidy phase-out would offer a fiscal benefit without significant effects on oil production, consumption or GHG emissions<sup>9,13,28</sup>.

Our research indicates a very different outcome if oil prices stay relatively low. We find that, at prices between US\$30 and US\$70 per barrel, subsidies cause at least 10%—and up to 90%—of oil in not-yet-developed fields to go from unprofitable to profitable. At US\$50 per barrel, about half of not-yet-developed oil is subsidy-dependent in this way.

Our analysis applies a number of key enhancements to prior studies, such as using detailed field-by-field data and simulating the impact of a broader suite of state and federal subsidies on industry decision-making.

It also converges with a recent study published by the Council on Foreign Relations using oil prices of about US\$75 per barrel<sup>28</sup>. That level is roughly equal to the average price, in 2016 US dollars, of oil over the past ten years. When we adjust to the same hurdle rate (15%) and subsidies analysed in the Council on Foreign Relations study, our approach produces an identical finding: that about 9% of the oil resource across all field types would be dependent on subsidies.

It is possible that prices could return to US\$75 per barrel or higher in the coming years, according to ‘business-as-usual’ projections by the International Energy Agency<sup>35</sup>. In that case, the effect of US subsidies on oil investment and production would be relatively modest. Still, there are reasons to believe that prices could stay closer to US\$50 per barrel for some time and, therefore, that a considerable fraction of new US oil investment will remain subsidy-dependent. For example, the International



**Fig. 3 | Subsidy-dependence as a function of oil price.** The impact of subsidies is highly sensitive to oil price. These charts show how much oil is economic at price levels between US\$30 and US\$100 per barrel according to whether it is already producing; discovered and economic without subsidies; discovered and economic only because of subsidies (‘subsidy-dependent’); or not yet discovered. **a**, Results at the base, 10% discount rate. **b**, Results at an alternative discount rate of 15%. The subsidy-dependence of the not-yet-discovered fields was not assessed, as these quantities are speculative, based on Rystad Energy’s assessment. Still, should they prove as subsidy-dependent as the fields we do assess, the impact of subsidies at higher prices would be larger than we currently estimate.

**Table 2 | Effect of subsidies on undeveloped oil resources and CO<sub>2</sub> emissions at US\$50 per barrel**

Area	Economic oil resources, discovered but not yet producing (billion barrels)	Percentage subsidy-dependent	Increase in economic oil resources due to subsidies		Increase in co-produced gas resources due to subsidies	
			(billion barrels)	(GtCO <sub>2</sub> )	(billion barrels oil equivalent)	(GtCO <sub>2</sub> )
Williston Basin	3.8	59%	2.3	0.9	0.2	0.1
Permian Basin	16.3	40%	6.5	2.4	1.6	0.5
Gulf of Mexico	2.1	73%	1.5	0.6	<0.1	<0.1
Rest of US	13.1	48%	6.3	2.4	1.3	0.4
Total US	35.3	47%	16.5	6.2	3.2	0.9

Energy Agency has described how a new oil market equilibrium could emerge 'at prices in the [US]\$ 50-60/bbl range', should other countries move to phase out fossil fuel consumption subsidies and the Organization of the Petroleum Exporting Countries and its allies continue to place a priority on market share instead of maximizing prices<sup>32</sup>. Although the Organization of the Petroleum Exporting Countries agreed in late November 2016 to production cuts, later extended in May 2017, questions remain about whether that will keep prices well above US\$50 per barrel for an extended period of time<sup>36,37</sup>.

Furthermore, international action to reduce greenhouse gas emissions and achieve the Paris Agreement's 2 °C goal would also make it more likely that oil prices remain in the US\$50–US\$60 per barrel range<sup>38</sup>. Measures that have been adopted or considered include removing fossil fuel consumption subsidies; raising fuel-efficiency standards; promoting electric, hybrid or hydrogen vehicles; encouraging the use of public transit and non-motorized modes of transportation; and substituting natural gas for oil in industry. Each of these actions could, if taken at scale, reduce demand for oil to such a degree that prices might never return to the US\$100 level on a sustained basis.

Our findings suggest an expanded case for fossil fuel subsidy reform. Not only would removing federal and state support provide a fiscal benefit and demonstrate US compliance with existing G20 commitments, but it could also result in substantial climate benefits. These benefits come through reduced oil production, oil consumption and global CO<sub>2</sub> emissions<sup>39</sup>. Furthermore, as others have noted<sup>13,28</sup>, phasing out fossil fuel subsidies at home could give the US added leverage in prodding other countries to reform their own, often more significant fossil fuel subsidies.

Although the prior US administration made strides towards phasing out federal fossil fuel subsidies, it remains unclear whether the new US administration will revive those efforts. During his presidential campaign, candidate Trump announced an intention to eliminate corporate tax breaks. As president, however, Mr. Trump has indicated an intention to expand oil and gas drilling<sup>40,41</sup>, charting an altogether different direction for federal policy. Regardless, a clear sense of the impacts of fossil fuel subsidies is essential to choosing the best path forward, in the US and elsewhere. The approaches we use here could be more widely applied to other fossil fuels and countries.

## Methods

**Field-level data.** We build our analysis from field-level data provided in Rystad Energy's UCube database as of mid-2016. Rystad estimates capital investment, operating costs, taxes and production profiles for each oil field in the US based on a combination of public (for example, lease documents) and private (industry-provided) sources<sup>26</sup>. A commercially available data set, Rystad's data have also been used extensively by the International Energy Agency<sup>35,42</sup>. It includes all oil and gas fields globally. Here we focus on oil fields in the US that have been discovered but not yet developed. These fields, more than 800 in total, are nearing decisions on investment in development infrastructure,

such as wells or offshore platforms<sup>43</sup>. Since the owners of these fields have already assessed potentials and economics, but have not yet developed them, the fields offer a prime opportunity to evaluate the influence of subsidies across the full life cycle of capital investment, operations and field abandonment. This lens allows us to analyse the effect of subsidies on the entire project lifecycle, including capital recovery. As a result, we do not consider how subsidies affect projects that were already producing as of 2016. Subsidies may also affect oil output from these projects, such as by extending the life of a well and thereby facilitating more production. However, this effect is likely to be smaller, as it would come late in the life cycle of most fields, after operators have already extracted the majority of their oil. We also do not address fields in the Arctic or offshore Atlantic, as these resources have not yet been proven profitable or been scheduled for development<sup>26</sup>.

**Subsidies considered.** To generate the list of subsidies we evaluated here, we relied on a number of public sources. These included an inventory of budgetary supports and tax preferences for fossil fuels assembled biennially by the Organisation for Economic Co-operation and Development<sup>4</sup>, as well as reports by the White House Office of Management and Budget<sup>44</sup> and the congressional Joint Committee on Taxation<sup>45</sup> that regularly assess the revenue losses from particular tax subsidies. We also used data from other US federal agencies (for example, the Bureau of Land Management or the National Transportation Safety Board) or state agencies (for example, the Texas Department of Transportation) that have considered the revenue or liability implications of different measures<sup>46–48</sup>. The Supplementary Methods provides further information about how each subsidy was assessed, including details of how we quantified the effect of each on investor cash flow.

Beyond the dozen measures included here, a number of additional supports to upstream oil production are in effect, but are not included in our analysis because they were too difficult to quantify, of relatively small magnitude, or applied primarily to currently operating fields rather than new ones.

**Modelling investor cash flow.** The oil industry uses numerous decision-making criteria to determine whether and how to proceed at each successive stage of oil field development. Early stages of deciding which assets or lands to acquire—and where and how to explore new fields—are often dominated by strategic considerations, such as the potential benefits of entering a new market, the potential risks associated with exploration in a new area, and the likelihood of each of these risks and benefits occurring<sup>43</sup>.

Once firms have sufficient information (for example, geophysical surveys and test-well data) to gauge potential costs and production levels, they commonly apply discounted cash-flow analysis to calculate a project's net present value (NPV) and the internal rate of return (IRR), and use one or both of these metrics to assess whether or not to proceed<sup>25,27,49</sup>. NPV is the sum of all future cash flows discounted to present value taking into account the company's investment hurdle rate. Investors would expect a project with a positive NPV to make a net profit and one with a negative NPV to lose money. Similarly, a firm that used IRR would proceed if the project's IRR was greater than its hurdle rate. (IRR is defined as the hurdle rate that returns an NPV of zero.) Hurdle rates of 10–15% are often used in the oil industry.

Discounted cash flow analysis is not the only tool that companies use to decide whether or not to develop a field, but it is the most common one<sup>25</sup>. Companies also assess various other measures of risk, not just related to uncertainty in financial parameters but also concerning political, legal, health, safety and regulatory risks that may or may not lend themselves to quantification<sup>49,50</sup>. Nevertheless, as the cornerstone of project-based decision-making, discounted cash flow analysis is a strong basis on which to assess the impact of subsidies, and has been frequently used by the oil industry in its own analyses<sup>27</sup>.

Accordingly, all subsidies are modelled as modifications to the cash flow and production streams, as drawn from data in Rystad Energy's UCube database. Rystad's UCube provides production and economic time series at the level of 'assets', which represent groups of oil and gas wells within a particular field or

licence. The data provided for each asset include, by year: oil and gas production, taxes and royalties, capital expenditures and operating expenses. We restrict our focus to fields for which the primary product extracted is crude oil, excluding fields that primarily produce natural gas. For the fields we do include, however, our analysis captures the cash flow impact of both oil and gas fuel sales and subsidies. We use a central case of US\$50 per barrel oil, since at the time of this analysis, oil prices were about US\$50 per barrel in both current and futures markets. However, we analyse the impact of subsidies at a range of oil prices, from US\$30 to US\$100 per barrel. In all cases, we use a wellhead gas price of US\$15 per 'barrel equivalent' gas, equivalent to US\$2.65 per thousand cubic feet (mcf), for the relatively small portion of natural gas produced at each crude oil field.

We calculate the effects of each subsidy in our model as sequential change in project IRR: that is, each subsidy modifies a cash-flow stream that includes the effects of any subsidies already applied. In this way, we automatically account for any interactions among subsidies. In most cases, the sequence by which we analyse subsidy impacts does not matter. Subsidies that are simple per-barrel reductions in costs, for example, can be applied in any order. In some important cases, the order does matter. For example, a reduction in tax rate due to a firm being classified as a master limited partnership would have no effect if other subsidies had already eliminated any taxable income (for example, due to IDC deductions that reduced taxable income to zero).

For this reason, a consistent and logical order in which to apply the subsidies must be defined, and then applied to every field. To guide us, we first apply a simple ordering rule: we apply the subsidies in an order approximating that in which firms would encounter them in the process of developing an oil field. More specifically, the first subsidies considered are those that affect costs before an oil field is developed (or, in some cases, before it is explored). These are, in the order they are applied in our model: limited bonding for site closure and reclamation; limits to insurance coverage for oil spills and accidents; transferring rail safety risks to public; public coverage of road damage costs; public financing of the US Strategic Petroleum Reserve; and reduced transport costs due to the corporate tax exemption for master limited partnerships. Since none of these costs directly depends on another, the order does not actually affect the results.

The next subsidies are those that affect the costs during exploring, developing and ultimately producing from the field. These include subsidies that affect the costs of geological or geophysical surveys as well as so-called intangible drilling costs. The order of some of these measures does matter. We apply them in the order in which they occur in a standard US income tax form, that is, Form 1120 for corporate income tax returns. Thus, we first apply subsidies that affect income, then subsidies that affect costs (including deductions for depreciation or depletion), and then subsidies that affect the actual tax rate paid. These subsidies are, in the order they are applied in our model: royalty exemption for flaring and on-site use; accelerated amortization of geological and geophysical expenses; expensing of intangible exploration and development costs; excess of percentage over cost depletion; domestic manufacturing activities deduction; and the Texas crude oil severance tax exemption.

The order here is particularly important, as the effect of one subsidy may depend directly on how a company elects to treat the prior subsidy. For example, the subsidy for percentage depletion allows companies to deduct (for tax purposes) a fixed percentage of income as costs instead of deducting costs along the way as the asset is depleted (which would be 'cost depletion'). However, because the level of cost depletion (against which the effect of percentage depletion is assessed) is directly dependent on whether intangible drilling costs (IDCs) were immediately expensed or not, the subsidies are inextricably linked. Certainly, some firms may use complicated optimization criteria to consider the interactions in more sophisticated ways than we do here. For simplicity, however, we just apply them in the order listed.

Of the dozen subsidies considered in our analysis, three measures affect how companies recover the costs of developing an oil field for tax purposes. To understand this, we must address how we treat the capital expenditures on which these tax subsidies depend.

**Treatment of capital expenditures.** Rystad's UCube provides capital expenditure streams for exploration, well drilling and facility costs. For tax purposes, these costs can be deducted from income. However, when and how they are deducted (regardless of subsidies) may depend on what the costs represent. These three streams also may have different tax implications; for example, the IRS may treat exploration costs differently from costs for building an offshore oil platform. Thus, we must estimate what fraction of each of Rystad's capital expenditure designations is eligible for each of the different means under which a taxpayer may 'recover' that expense.

In brief, capital expenditures considered physical property, such as an oil tank, have a salvage value at the end of life and must be depreciated according to fixed schedules<sup>51</sup>. Table B-2 of IRS Publication 946 describes recovery periods for most classes of assets and the corresponding depreciation schedules<sup>52</sup>, which for most assets is seven years. As per Table 4-1 of IRS Publication 946, we assume that the 200% declining balance method of depreciation 'provides a greater reduction during earlier recovery years' and is therefore standard, and so we use depreciation schedules as in Table A-1 of Publication 946.

By contrast, capital expenditures that are not considered physical property, such as fees paid to a driller, often contribute to the market value of a property but

have no salvage value. These costs (sometimes called 'intangible') are recovered through cost depletion (in the unsubsidized case), via immediate expensing as IDCs, or via an accelerated amortization schedule for geological and geophysical exploration expenses. If recovered through cost depletion, the costs are added to the taxpayer's ongoing calculation of their 'depletable basis' and recovered over time in proportion to production, following IRS Publication 535, chapter 9<sup>53</sup>.

Rystad does not estimate what fraction of capital expenditures are physical property, however. As a result, we use the approximations reported by Wood Mackenzie in their study for API<sup>57</sup>, as further detailed under the Treatment of capital expenditures section in the Supplementary Methods.

**CO<sub>2</sub> emissions associated with added oil production.** To estimate CO<sub>2</sub> emissions associated with the oil and gas extracted, we use Rystad's energy content of 5.51 million British thermal units (MMBtu) per barrel and apply standard carbon contents from the US Environmental Protection Agency's national greenhouse gas inventory of 20.31 kg C per MMBtu of crude oil and 14.46 kg C per MMBtu of gas<sup>54</sup>. We then discount these totals by the amount of carbon stored from each product, estimated to be 8.02% for oil and 1.86% for gas, due to use of oil and gas to manufacture non-fuel products, such as plastics, that are not burned<sup>55</sup>. We also exclude any greenhouse gas (methane) associated with venting, flaring or leakage during production or transportation of those resources.

**Data availability.** Source data for Fig. 1 can be found in Supplementary Data 1. The data that support other plots within this paper and other findings of this study are available from the corresponding author upon reasonable request. The raw data analysed by the authors are available from Rystad Energy in their UCube database<sup>56</sup>, but restrictions apply to the availability of these data, which were used under licence for the current study, and so are not publicly available. Raw data are available from the authors upon reasonable request and with permission of Rystad Energy.

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## Author contributions

P.E., M.L. and D.K. designed the research, A.D., P.E. and D.K. conducted the analysis, and P.E. wrote the manuscript with contributions from A.D., M.L. and D.K.

## Competing interests

The authors declare no competing financial interests.

## Additional information

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