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Peter Erickson, Adrian Down and Michael Lazarus, Stockholm Environment Institute
Doug Koplow, Earth Track

SEI - U.S. Seattle Office
1402 Third Avenue, Suite 900
Seattle, WA 98101
USA

Tel: +1 206 547 4000
Web: www.sei-international.org

Author contact:
Peter Erickson,
peter.erickson@sei-international.org

Acting Director of Communications: Tom Gill
Editor: Marion Davis

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ABSTRACT

The United States now produces as much crude oil as ever – over 3.4 billion barrels in 2015, just shy of the 3.5 billion record set in 1970. Indeed, the U.S. has become the world's No. 1 oil and gas producer. The oil production boom has been aided by tax provisions and other subsidies that support private investment in infrastructure for oil exploration and development. Federal tax preferences, for example, enable oil and gas producers to deduct capital expenditures faster, or at greater levels, than standard tax accounting rules typically allow, boosting investment returns. This paper quantifies the effect of a dozen U.S. federal and state subsidies to oil production and estimates the corresponding effects on global CO_2 emissions. At recent oil prices of $50 per barrel, subsidies push nearly half of yet-to-be-developed oil into profitability, potentially increasing U.S. oil production by almost 20 billion barrels over the next few decades. Once burned, this oil would emit 8 billion tonnes of CO_2, about 1% of the world's remaining carbon budget to keep warming under 2°C, as envisioned in the Paris Agreement. This would represent a much greater share – perhaps a quarter – of a carbon budget for U.S. oil production alone. These findings suggest an even stronger case for subsidy reform than has been articulated to date. Not only would removing federal and state support provide a large fiscal benefit to apply to other national spending priorities; it would also demonstrate U.S. compliance with existing G20 commitments and generate substantial climate benefits as well.

CONTENTS

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1. INTRODUCTION

The United States now produces as much crude oil as it ever has. Production of crude reached 3.4 billion barrels in 2015, just shy of the early 1970s high of 3.5 billion barrels annually (U.S. EIA 2016a). Indeed, if natural gas liquids are also included, the U.S. produces more oil than ever, and has even surpassed Saudi Arabia (BP 2016).

The rise in U.S. oil production has been driven by the rapid growth of hydraulic fracturing and horizontal drilling technology. New investments in unconventional upstream oil (and gas) technologies have totaled at least $20 billion in each year since 2006, reaching as high as $130 billion in 2014. Coupled with new investment in conventional onshore and offshore oil, total upstream investment in U.S. oil and gas production exceeded $200 billion in 2014 (Rystad Energy 2016). While the recent drop in oil prices has slowed investment, the International Energy Agency (IEA) still expects the U.S. to lead the world in upstream oil and gas investment over the next two decades, averaging more than $150 billion per year (IEA 2015).

Numerous federal tax provisions specifically support private investments in fossil fuel infrastructure. For example, some tax preferences for oil and gas producers enable them to deduct capital expenditures more rapidly (or at greater magnitude) than standard tax accounting would typically allow, thus improving investor cash flow.

As oil investment and production have soared, so too have government tax expenditures. Official government estimates of the cost of subsidies to the oil and gas industry total $2 billion to $4 billion annually (OMB 2016; Joint Committee on Taxation 2015; U.S. Government 2015). Furthermore, the federal and several state governments also provide a variety of other subsidies to oil and gas exploration and extraction. These include federal and local royalty exemptions; the transfer of liability for oil spills or clean-up of abandoned wells; and public funding for supporting infrastructure, such as roads, that is not adequately recovered through user fees. Including a number of these other subsidies, other researchers have estimated the annual subsidies supporting oil and gas to be $17.5 billion (Bast et al. 2015).

Ironically, oil production and investment surged at a time when the U.S. was deepening its commitments to addressing climate change. President Obama supported the Paris Agreement, which calls for a global effort to keep warming "well below" 2°C and to try to keep warming below 1.5°C (UNFCCC 2015). Yet a cost-efficient approach to attaining the 2°C goal would require reducing global production of fossil fuels – including oil (IEA 2015). Investment in new upstream fossil fuel supply infrastructure would need to decline as well (IEA 2014). Recent analysis suggests that U.S. oil production might need to drop by at least 40% from current levels by 2040 to be consistent with a 2°C target (Erickson and Lazarus 2016).

Still, the U.S. continues to subsidize oil production. Although every federal budget proposed by the Obama Administration sought to repeal the largest federal subsidies to oil and gas production, and the U.S. committed to their elimination in the Group of Twenty (G20) international forum (G20 2009), reform proposals have systematically failed in Congress. How a Trump administration and a new Congress will approach subsidies is unclear.

1.1 The effects of subsidies to oil producers

An important recurring question in these debates is how the subsidies affect oil production, consumption, and global carbon dioxide (CO_2) emissions, as well as how much these amounts would change with subsidy removal. Yet despite the G20 commitments to phase out fossil fuel subsidies as part of efforts to address climate change, relatively few analyses have considered this question in detail (Merrill et al. 2015; Ellis 2010).[1]

In principle, subsidies to either fossil fuel consumers or producers will tend to increase production, consumption and CO_2 emissions. There are a handful of pathways for this to happen. Since many subsidies tend to lower consumer prices, they encourage consumption and investment in technologies that burn fossil fuels. Fossil fuel subsidies also erode the competitiveness of substitute fuels and technologies, slowing their development and market growth. Producer subsidies, in particular, can increase the attractiveness of investments in fossil fuel exploration, extraction, processing and transport and thus lead to added production. The resulting growth in fuel supply can lower prices, drive up fuel consumption, and increase CO_2 emissions, relative to a situation without subsidies.

Indeed, a common justification for producer subsidies is that they can stimulate added economic activity in producing regions or – through increased domestic production – improve the balance of trade and enhance energy security. However, subsidies can also flow to producers without affecting their investment and operating decisions – an occurrence referred to as “subsidy leakage”, in which public funds increase producers’ or resource owners’ profits – with little effect on production levels, market prices or consumption levels.[2] Which of these two effects predominates – increased production or increased profit – depends on the nature of the subsidy, its effect on producer behavior, and prevailing market conditions.

Although aggregate U.S. federal subsidies to oil and gas production are tabulated regularly, research on the effect of these subsidies on oil and gas production decisions and profitability has been much more limited. Research findings tend to fall into two main groupings: industry-sponsored studies that suggest subsidies (especially the ability to deduct intangible drilling costs) have a major influence on investment decisions and production levels; and research-institute publications that conclude such impacts are relatively small. For example, in a study indicative of this first group, Wood Mackenzie, in a report for the American Petroleum Institute, found that without subsidies to oil producers, “many projects will no longer meet investment criteria”, and thus their removal would have a “significant impact” on future production (Wood Mackenzie 2013, p.3).

By contrast, in a series of Brookings reports on options for tax reform, Aldy (2013), drawing on work by Resources for the Future (Allaire and Brown 2012), suggests that most of the major oil and gas subsidies go directly to producer profits, and have relatively little effect on investment or production levels. This work looked at aggregate effects (i.e., not field-specific) on national oil and gas markets and, unlike the Wood Mackenzie study, did not assess investor behavior. As a result, it did not account for how the value of subsidies to producers can increase if they are applied earlier in the project life cycle, nor did it account for how particular fields might disproportionately access federal or state supports. Consequently, Aldy (2013) and Allaire and Brown (2012) may have underestimated the effects of subsidies on investment in, and production of, petroleum.

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[1] By contrast, analysis of the effects of consumer subsidy reform are more numerous; see, for example, Burniaux and Chateau (2014) and Schwanitz (2014).

[2] While subsidies to oil and gas fields that would be profitable even absent government support do not affect production levels or prices, they may still alter activity over the longer term. Outsize profits attract more capital, on better terms, than would otherwise be available. Cash flows within a firm may also be elevated. Both factors can increase the viability of the oil and gas sector relative to an unsubsidized baseline, with increased long-term investment boosting production.

More recently, an analysis published by the Council on Foreign Relations advances the method used by Aldy (2013). The study (Metcalf 2016) modeled firm behavior from an investor perspective, considering which types of firms are eligible for the three largest federal subsidies. It still reached a similar conclusion as Aldy (2013): producer subsidies have a relatively small effect on petroleum investment or production.

This paper presents a more granular approach to assessing the effect of U.S. subsidies on oil production, discussed below. In Section 2, we describe the scope and method, including details of the basins we selected and the subsidies we analyzed. Section 3 presents our results in detail (with discussion), and Section 4 offers conclusions and policy implications.

1.2 Distinctive features of this study

Although our analysis builds on prior work, it differs from these earlier assessments in several important respects. First, we examine a broader suite of government support to upstream oil and gas operations. We look at a dozen in total, not only commonly reported federal tax incentives (Nordhaus et al. 2013), but lesser-known federal tax preferences, some state-level support, and non-tax subsidies such as liability transfers and infrastructure support. The combined effects of multiple subsidies flowing to a specific project, sometimes referred to as "subsidy stacking," can tip a low-return project into one that is "investable". Assessing subsidies in isolation, or looking at too narrow a subset of available supports, can fail to capture their interactions and joint effects.

Second, we assess how these subsidies affect the return on investment in new U.S. oil production using detailed field-level economic and production data. The use of project-level data enables us to highlight the extent to which government support goes directly to profit (representing a transfer payment from taxpayers to industry), versus converting otherwise unprofitable projects into profitable ones, and thereby enabling them to proceed (leading to added oil production and CO_2 emissions). Our review includes field-by-field case studies of three large U.S. oil basins (Texas/Permian, North Dakota/Williston and offshore), evaluating state-level subsidies in detail as well as those from the federal government. For all other U.S. fields, we assess federal support only. The analysis provides insights into how subsidies may differentially affect particular regions and resource types (e.g. offshore vs. onshore, tight oil vs. conventional oil).

By assessing the manner and degree to which government support tilts the economics of new investment in oil production, we can evaluate a number of related impacts. These include the extent of new upstream oil investment in the United States; the barrels of oil and CO_2 emissions that result from production capacity that would not have been developed absent the subsidies; and the fraction of subsidy value that flows to projects that would have been economically attractive even without subsidies. This investment-oriented approach is similar to that used by industry and industry-sponsored studies (e.g. Wood Mackenzie 2013).

Our analysis focuses on fields drilled primarily for crude oil production, which account for about two-thirds of total "liquids" production in the U.S. (Rystad Energy 2016). While most of the subsidies examined here also apply to natural gas fields (which also produce some liquids),[3]

[3] The remaining liquids are produced by separation from natural gas either at natural gas wells ("condensate") or during processing of natural gas ("natural gas plant liquids", NGPL or NGL). Likewise, fields drilled primarily for crude oil can also produce some natural gas. We include revenues for (and subsidies to) this gas production in our assessment of each crude oil field.

we do not consider these fields here, given the resource-intensive nature of our method as well as the ambiguous impacts of added gas production on net GHG emissions.[4] We expect that the effect on gas field profitability would be similar, and note that a deeper look at the effect of subsidies on gas production could be a natural extension to our analysis.

2. STUDY SCOPE AND METHOD

One of the limitations of most prior analyses of U.S. producer subsidies is that they look at U.S. oil production in aggregate, with relatively little consideration of how subsidy effects may vary depending on the specific economic considerations faced by each producer type (Allaire and Brown 2012; Krueger 2009). In studies using aggregate approaches, subsidies are implicitly assumed to have a similar effect on the cost of producing oil (e.g. in dollars per barrel) among all producers benefiting from each subsidy. For example, an independent producer of offshore oil in the Gulf of Mexico would experience a similar boost from the subsidy as an independent onshore producer in North Dakota.

Because of this averaging effect, aggregate approaches are more likely to underestimate the potential effects of subsidies. This is because, as described in one recent analysis (Metcalf 2016), investors are not concerned with the aggregate (or average) value of a subsidy to the *industry* as a whole, but rather with how subsidies affect the timing of cash flows for specific projects, especially near the time when up-front investments are made. In particular, investors consider the time value of money – the fact that a dollar in the first few years of investment can be worth much more than a dollar in later years – and therefore have a disproportionate impact on the decision to go ahead with a project. To model these effects, one needs to look at the distribution of cash flows over time, and to do so at the individual project level. In addition, subsidy eligibility can vary by the size and corporate structure of a producer, and by location – factors that are possible to integrate in our field-level assessments.

To address these considerations, we adopt an investment perspective. We analyze the effect of subsidies on typical investment metrics such as the internal rate of return (IRR) and net present value (NPV), approaches that capture how subsides would affect cash flow and financial returns. (See Box 1 on decision-making in upstream oil investment.)

In order to take this investment perspective, we look at the effects of subsidies at a much more detailed level – that is, specific fields owned by particular companies. This allows us to understand more clearly how different subsidies may interact to have greater (or lesser) cumulative effect, depending, for instance, on whether a specific field or company qualifies for the most generous benefits of the tax code or other subsidies.

Below we describe further details of the scope of our analysis – which basins we focus on, and which subsidies we include – and then provide more details on how we conduct the cash flow analysis.

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[4] The CO_2 and greenhouse gas balance of increasing oil availability is more certain than that of gas. This is largely because oil is a more carbon-intensive fuel for which likely alternatives (e.g. electricity, second-generation biofuels, or compressed natural gas) are likely to be of similar or of lower carbon intensity. In such circumstances, expanding the supply of oil is likely to increase GHG emissions, as it both expands the use of oil and displaces lower-carbon fuels. By contrast, increasing natural gas supply can, at least in the next couple decades, displace both high-carbon (e.g. coal) and lower-carbon (e.g. renewable) power sources, leading to both emission decreases and increases (respectively) that may come close to cancelling each other out (Shearer et al. 2014; McJeon et al. 2014; Lazarus et al. 2015).

Box 1: Decision-making in upstream oil investment

The oil industry uses numerous decision-making criteria to determine whether and how to proceed at each successive stage on the path to extraction. Early stages of deciding which assets or lands to acquire – and where and how to explore new plays – 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 (Jahn et al. 2008a).

Once firms have sufficient information (e.g. 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. (Jahn et al. 2008b; Bailey et al. 2000; Wood Mackenzie 2013). NPV is the sum of all future cash flows discounted to present value taking into account the company's investment hurdle rate. A project with a positive NPV would be expected to make a net profit, while one with a negative NPV would not. 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 (Bailey et al. 2000). Companies also assess various other measures of risk, whether related to uncertainty in financial parameters, or political, legal, health and safety, and regulatory risks that may or may not lend themselves to quantification (Passone and McRae 2007; Jahn et al. 2008b). 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 is the method also used by the oil industry itself in its own analyses (Wood Mackenzie 2013). Based on the literature and consultation with oil industry experts, we apply discounted cash flow analysis here as the central criterion by which we gauge the potential effects of subsidies.

2.1 Areas examined

We examine all crude oil fields in the United States that have been discovered but have not yet been developed – i.e., they were not yet producing as of mid-2016. These fields are nearing (or are in) the "appraisal" stage, with decisions on investment in development infrastructure, such as wells or offshore platforms, not yet made (Jahn et al. 2008). That means these fields may best reflect the influence of subsidies, since several subsidies – including the most prominent federal tax incentive, the expensing of intangible drilling costs – are directed at the early stages of field development, including up-front capital investment.

We also include a more detailed look at three specific areas of U.S. crude oil production: the Permian basin, the Williston basin, and offshore, federally administered fields in the Gulf of Mexico. By examining the Permian and Williston basins (mostly located in Texas and North Dakota, respectively), we can explore the interaction of federal and state subsidies in the two largest oil-producing states. These are also the largest U.S. basins in terms of crude oil reserves, rely heavily on horizontal drilling and hydraulic fracturing, and are dominated by smaller producers that are able to access federal tax preferences more fully than can larger integrated oil producers (U.S. EIA 2015). By contrast, offshore deposits in the Gulf of Mexico are typically tapped by large producers in federal waters, requiring relatively long lead times and large amounts of capital investment, with a more limited array of subsidies currently available.[5] As shown in Table 1 below, each of these three areas contains between 4 and 7 billion barrels of oil in proved reserves and together account for nearly half of total U.S. oil production.[6]

We consider fields in the rest of the U.S. together as a fourth area. Because we consider only federal, not state, subsidies in this fourth region, subsidy impacts will be somewhat understated. These fields include 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 in Wyoming's Powder River Basin or Oklahoma's Anadarko basin, as well as other offshore sources in Alaska. Deposits in the Arctic or offshore Atlantic do not factor into our analysis, as these resources have not yet been proven profitable or been scheduled for development.[7]

Table 1: Characteristics of U.S. production areas assessed here

Basin	Subsidy jurisdictions considered	Current crude oil proved reserves, billion barrels	Number of not-yet-developed fields assessed
Williston	Federal, North Dakota	6.0 billion	107
Permian	Federal, Texas	7.0 billion	192
Gulf of Mexico	Federal	4.5 billion	79
Rest of US	Federal[8]	25.2 billion	440
Total U.S.		**36.4 billion**	**818**

Sources: Proved reserves: U.S. EIA (2015); Number of not-yet-developed fields: Rystad Energy (2016).
Note: Proved reserves represent those with a very high probability of being recoverable in the Energy Information Administration (EIA)'s assessment. Our subsequent analysis uses an assessment of the total economical resource, which may be higher.

Though we consider only discovered, not-yet-producing fields, subsidies may also affect oil output from projects that are already producing. This can occur when the subsidies extend the life of a well, allowing more production than would otherwise occur. Due to data limitations and the complicated considerations involved in deciding when to cease production at a well, our analysis does not capture these effects. We anticipate that any stimulating effect that subsidies to existing projects have on national oil production would be small compared with the effect of bringing new investments online. This effect also diminishes over time, as production from existing fields declines and is replaced by new investments.

[5] Some offshore oil was previously eligible for substantial royalty subsidies, such as under the Outer Continental Shelf Deep Water Royalty Relief Act (Vann 2014) for leases issued between 1996 and 2000. Though this subsidy still persists for those particular eligible leases, it is no longer available for new development. Because our analysis focuses only on new production, we do not consider these royalty subsidies here.

[6] Per the EIA's estimates as of 12/31/14, federal offshore oil in the Gulf of Mexico contains 4.5 billion barrels of oil, North Dakota contains 6.0 billion barrels, and Texas' RPC districts 7C, 8, and 8A (representing the Permian Basin) contained 7.0 billion barrels. See https://www.eia.gov/dnav/pet/pet_crd_pres_a_EPC0_R01_mmbbl_a.htm.

[7] Similarly, production of oil as a co-product from gas wells, e.g. from the Marcellus Shale in Pennsylvania, is not included.

[8] For assets included in this group that are located in Texas but outside of the Permian basin, we also estimate uncompensated road damages associated with production in these assets, a state-level subsidy

2.2 Subsidies considered

We focus on three categories of subsidies: forgone government revenue (especially taxes), transfer of liability to the government, and below-market government provision of goods or services.[9] These measures all confer a financial benefit from government to oil producers, and for this reason we consider them as subsidies.[10]

To generate the list of subsidies we evaluated here (Tables 2 and 3), we looked to a widely cited inventory of budgetary supports and tax preferences for fossil fuels by the Organisation for Economic Co-operation and Development (OECD 2013).[11] We also looked to the White House Office of Management and Budget (OMB 2016) and the congressional Joint Committee on Taxation (Joint Committee on Taxation 2015), both of which have assessed the revenue implications of repealing several measures. Lastly, we also looked to other U.S. federal agencies (e.g. the Bureau of Land Management or the National Transportation Safety Board) or state agencies (e.g. the Texas Department of Transportation) that have considered the revenue or liability implications of different measures. Beyond the dozen measures included here, a number of additional supports to upstream oil production are in effect, though not included in our analysis because they were either too difficult to quantify or of relatively small magnitude.[12]

[9] These types of support are widely recognized as subsidies, including by the WTO, as long as their provision is "specific to an enterprise or industry or group of enterprises or industries" and confers a "benefit" to the recipient. Though the definition of "benefit" is not always precise, the provision of tax incentives is generally understood to be a benefit, as is the transfer of liability and provision of goods and services to the extent they lower costs to the firm below which they would otherwise be, e.g. below market rates or below "adequate" remuneration (WTO 1994). Disagreement from recipients on what is or is not a subsidy is fairly common (API 2015), as is what other benefits (or costs) may justify (or not) any particular measure. Not surprisingly, the industry tends to argue that whatever benefits it receives are either not subsidies, or generate far more benefits to society than they cost.

[10] This follows the definition of the World Trade Organization (WTO). The WTO's Agreement on Subsidies and Countervailing Measures (WTO 1994) sets forth the most widely used definition and criteria for delineating what is and what is not a subsidy for the purposes of international trade. We note that this definition may be unnecessarily restrictive when applied within a country. We use the WTO's principles of (i) a financial contribution; (ii) by a government or any public body; that (iii) confers a benefit to guide our selection of support measures.

[11] The OECD uses the term "supports" rather than "subsidies" because member states and beneficiary industries frequently argue over whether a support is a subsidy, or something else that is justified because of a benefit the country gets, or because of some market impediment the support is needed to overcome. The definitional fights proved to be a distraction from the core objective of increased transparency, which using the more neutral term "support" enabled the OECD to reach.

[12] For example, see the longer inventory in Bast et al. (2015).

Table 2: Subsidies considered that reduce government revenue

Subsidy	Description	Tax payments are avoided or postponed by	Federal or state government reference
Expensing of exploration and development cost	Allows oil producers to deduct many drilling and field development costs associated with domestic oil wells that for other industries would be capitalized	Deducting immediately instead of under standard Internal Revenue Service cost recovery schedules	OMB (2016)
Excess of percentage over cost depletion	Allows selected producers to deduct a portion of the gross value of their production rather than standard deduction rules based on invested capital	Taking the (more generous) depletion allowance instead of using standard "cost depletion"	OMB (2016)
Domestic manufacturing deduction	Enables manufacturers to deduct a percentage of "gross income" from taxable income	Deducting 6% of income from oil and gas as tax-free	OMB (2016)
Accelerated amortization of geological and geophysical expenses	Allows independent producers to amortize geological and geophysical expenses over two years rather than the producing life of well	Amortizing these expenses over two years rather than using standard "cost depletion"	OMB (2016)
Corporate tax exemption for master limited partnerships	Enables firms to avoid corporate income taxes, a special allowance available predominantly to the fossil fuel industry	Reduction in income tax burden relative to other industries	Joint Committee on Taxation (2015)
Royalty exemption for flaring and on-site-use	Operators are not required to pay royalties on gas production that is consumed on-site to power equipment or flared on site	Not paying royalties for on-site use or flaring (at state average rates per unit of oil production)	BLM (Kendall 2010)
Texas crude oil severance tax exemptions	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)	Paying 2.3% instead of 4.6% severance tax rate at Permian wells using EOR	Texas Railroad Commission (2015)

Table 3: Subsidies considered that transfer liability or provide goods or services

Subsidy	Description	Costs to oil producers is lowered by	Federal or state government reference
Limited bonding for site closure and reclamation	Jurisdictions routinely allow producers to provide assurance (e.g. via bonding) for less than the actual known costs of closure and reclamation of oil wells, transferring risk to the public (Boyd 2001; Mitchell and Casman 2011)	Reducing the cost of bonding from the foreseen actual cost of reclamation to the lower requirement in each jurisdiction (state or, for offshore oil, federal jurisdiction)	U.S. GAO (2011)
Transferring rail safety risks to public	Safety standards for rail cars used to carry oil remain below the National Transportation Safety Board's recommendations, transferring risk to the public	Lowering the cost of rail transportation of crude (relative to NTSB recommendations) by an amount estimated in a study by the American Petroleum Institute (ICF/API 2014)	U.S. DOT (2015)
Limits to insurance coverage for oil spills / accidents	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 cleanup mechanisms (e.g. Oil Spill Liability Trust Fund) inadequate, underpricing this risk to producers	Limiting the cost of insurance substantially below (coverage of $150 million or less) the maximum insurance available ($1.5 billion, and which is only a fraction of maximum damage cost)	National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (2011)
Public financing of the U.S. Strategic Petroleum Reserve	The U.S. Strategic Petroleum Reserve is maintained using federal tax revenue to fund infrastructure that provides hedging and borrowing capacity for private industry	The Department of Energy operates a service that would otherwise (i.e., in most other countries) be operated or funded by industry or other oil interests. Since consumers also benefit, only half of the subsidies have been counted as an industry subsidy.	Government Accounting Office (Fultz 1989)
Public coverage of road damage costs	Increased costs of maintenance and restoration of roads due to very heavy loads associated with oil and gas activities that are not fully covered by the industry	Limiting the cost of road maintenance for roads providing access to and from oil wells to annual overweight vehicle fees, substantially less than the actual maintenance cost	Texas DOT (2012) North Dakota Department of Transportation (NDDOT 2015)

2.3 Estimating the effect of subsidies on profitability and project development

We conduct our field-by-field analysis using detailed economic and production data maintained by the oil industry consultancy Rystad Energy (2016). Rystad estimates capital investment, operating costs, taxes, and production profiles for each oil field in the U.S. based on a combination of public (e.g. lease documents) and private (industry-provided) sources.

Using these cash flow 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. (Box 2 shows an example of the cash flow streams that we modify.) For example, we decompose Rystad's capital estimates to isolate expenses for intangible drilling costs (IDCs).

We then calculate the tax deductions (in the case without subsidies) by recovering them just like other capital invested in oil fields – either through depreciation (usually over seven years) or over time as the asset is depleted, through a provision of the U.S. tax code called "cost depletion". In the case *with* subsidies, we expense the IDC costs immediately for independent firms, generating higher tax deductions in the early years of operation. The approach is adjusted for integrated firms, as they are allowed to expense only 70% of their IDCs. Although the added deductions in early years are offset by lower deductions later on, the deferral of tax liability increases investor return on a present-value basis. As a result, the IRR is higher in the case *with* subsidies than in the one without. The difference reflects the value of the subsidy.

Other subsidies may instead affect operating costs, such as those that transfer liability by limiting insurance coverage required by oil producers for spills or accidents. In all cases, we account for eligibility, since not all subsidies apply to all firms. Particular tax breaks, for example, are available only to independent (non-integrated) producers or limited to a certain level of annual production. We describe the rules for which subsidies apply in each circumstance, as well as details about how each subsidy has been quantified, in Appendix 2.

The impact of subsidies also depends on what future oil price investors are expecting. As of the time of this analysis (summer–autumn 2016), oil prices were about \$50 per barrel in both current and futures markets. However, were prices to increase (as some EIA projections suggest) or decrease, the effect of subsidies on upstream oil investment could be quite different. Thus, we analyze the impact of subsidies at a range of oil prices, from \$30 to \$100 per barrel.

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 (Bailey et al. 2000) and also by Rystad Energy (2016), the source of the cash-flow data used here.[13] In practice, investor hurdle rates may vary depending on risk expectations and financing strategies. Other oil industry analysts (Wood Mackenzie 2013; Metcalf 2016) have used a hurdle rate of 15%, and so we also run a sensitivity analysis using that higher rate.

In keeping with standard project financial analysis, we assume that projects with expected returns below the hurdle rate are unprofitable and hence not developed, and those that meet or exceed it are sufficiently profitable to proceed. This approach enables us to estimate, for any given oil price, which projects would go forward even without subsidies (or would not proceed even with subsidies), and which are profitable only with subsidies included. By aggregating across all fields, we can then estimate how many barrels of oil resource are economical only because of subsidies.

Lastly, we examine the extent to which any subsidy-induced increases in oil *production* may affect oil *consumption* (Allaire and Brown 2012; Larsen and Shah 1992) and, in turn, incremental CO_2 emissions. This distinction incorporates the fact that some portion of the decline in domestic production is likely to be replaced by increased imports (or different domestic resources), moderating the net reduction in oil consumption in the market. Similar to other researchers (Metcalf 2016; Bordoff and Houser 2015; Industrial Economics Inc. 2015), we employ a simple supply-demand economic model of the world oil market that relies on own-price elasticities to characterize how a change in supply leads to a change in consumption.[14]

[13] Accordingly, we also use a 10% discount rate when we calculate the net present value effect of subsidies in order to estimate the proportion of subsidy value that goes to different types of fields.

[14] We estimate the change in global oil consumption as the product of the change in U.S. production as a result of subsidies and the ratio of the elasticity of world oil demand to the difference of the elasticities of demand and supply (Erickson and Lazarus 2014).

This approach is described in more detail in our prior work (Erickson and Lazarus 2016; Erickson and Lazarus 2014).

Box 2: Modeling the effect of subsidies on investor cash flow

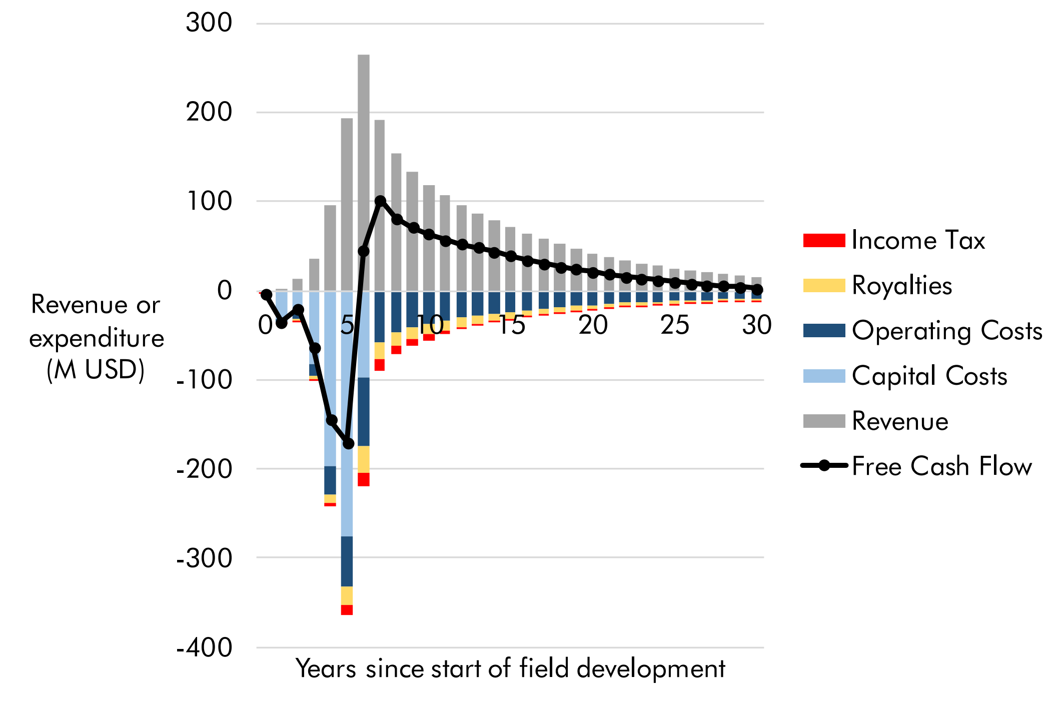
The chart below shows a sample cash flow of a hypothetical oil field. Up-front capital expenditures (in many cases totaling many millions of dollars) are concentrated in the first few years of the project, as wells are drilled and facilities put in place to extract and ready the oil for transportation. These costs include both tangible costs for physical items such as storage tanks, and intangible costs such as for well drilling and construction. Production (and, therefore, revenue) starts – and peaks – shortly thereafter, and then starts a gradual decline. Operating costs occur each year, as do royalties and taxes in most years where there is production, depending on the degree of revenue or profit.

We assess the internal rate of return (IRR) of each project based on its free cash flow, which is the incurred cash flow available to investors and creditors. Free cash flow is calculated as the difference between revenue and capital, operating, and tax and royalty costs in each year; it is shown in the chart as a black line connecting circles that represent the free cash flow values in each year.

The IRR of the sample project shown below is 9%, meaning that the net present value (NPV) of the free cash flow at a hurdle rate of 9% is zero. Stated another way, revenue from oil sales is roughly sufficient to cover capital and operating costs and yield a profit equivalent to 9% of capital investment.

We then quantify the effect of each successive subsidy by modifying the appropriate portion of cash flow and recalculating IRR. For example, we adjust the income tax (by adjusting the rules that we use to calculate that tax) for subsidies that change depreciation or depletion rules, such as the IDC or percentage depletion deductions. The result is a "with subsidies" IRR that typically exceeds the "without subsidies" IRR by several percentage points.

Some subsidies instead modify other portions of cash flow. For example, we quantify the road maintenance subsidy as a credit to operating costs. Whereas in the unsubsidized case, a firm using local unimproved roads would be responsible for maintenance costs, in the subsidized case these costs are borne by the state (and deducted in our calculations from operating costs).



3. RESULTS AND DISCUSSION

At prices of $50 per barrel, we find that roughly 24 billion barrels of oil in discovered but not-yet-producing fields would be economic without subsidies. With subsidies, the boost in discounted project cash flows is sufficient to make about 43 billion barrels' worth of new oil investments profitable, an increase of nearly 80 percent.

Considering the additional 29 billion barrels of oil in fields that are already producing, subsidies increase the economic oil resource by more than a third in total, from 53 billion to 72 billion barrels. For a given price, the proportional increase in economic oil resource due to subsidies could grow over time, as already-producing fields are depleted and not-yet-producing fields become more dominant. [15]

Our analysis also suggests that the effect of subsidies would be much weaker at higher oil prices. For instance, at $100 per barrel, nearly all already-discovered fields are economic even without the subsidies considered here. In this case, subsidies would instead have the effect of increasing profits, but have little effect on production.

Before delving into more detail on these findings, it is useful to present some broader findings on how the subsidies affect investor decision-making. We discuss the relationship between the subsidies, investment decisions, and the resulting increase in the overall economic oil resource.

3.1 Effect of subsidies on project economics

Across all U.S. oil fields considered,[16] we find that subsidies increase the internal rate of return (IRR) of most oil projects by 2–6 percentage points (median value of 3 points).[17] Figures 1a–1d show the effect of this subsidy-induced bump in project return across the hundreds of fields assessed, divided across the four regions considered.[18] Whether this bump in return affects a given project's investment decision in our analysis depends on whether the subsidies tip the project from being uneconomic to economic. This can be seen in the figures, with the IRR increasing from below to above the hurdle rate (shown as a grey, dashed horizontal line). If the project is already profitable (i.e., IRR without subsidies is above the hurdle rate), then the project would have proceeded anyway. Similarly, we assume that if a project's IRR remains below the hurdle rate even after subsidies, then the project would not proceed in either case.

As indicated above, at current prices of $50 per barrel, subsidies push enough projects above the 10% hurdle rate to bring about an extra 20 billion barrels of oil online. Nearly 8 billion of these barrels are in Texas' Permian Basin, which can provide a good illustration of the effects.

As shown in Figure 1a, about 12 billion barrels of Permian oil are in fields that would be profitable at $50 per barrel even without subsidies. These fields are the small blue dots, each

[15] For example, Rystad projects that not-yet-producing fields (both discovered fields and its estimates from fields not-yet-discovered) may account for 75% of U.S. oil production by 2025, rising to 90% by 2040, as existing fields are depleted.

[16] We also account for subsidies for natural gas co-production at fields predominantly developed for their crude oil potential.

[17] Across all projects analyzed, the 25th percentile of change in IRR was 2 percentage points, and the 75th percentile of change in IRR was 6 percentage points.

[18] For larger, high-resolution versions of the figures, see https://www.sei-international.org/publications?pid=3036. The figures show only the projects for which IRR becomes positive at $50/barrel. Some projects never reach a positive IRR (even with subsidies) and are not shown; those projects tend to show a smaller increase in IRR from subsidies, which explains why the median increase of 3 points (and 25th to 75th percentile range of 2 to 6 points) is smaller than what one might infer from these figures alone.

representing a field with an IRR of above 10%, on the left side of the chart above the horizontal hurdle rate line. Since these projects were going to proceed even without subsidies, the entire added value of the subsidy (the "bump" in IRR between each blue dot and the small grey dot directly above it) goes to profit.

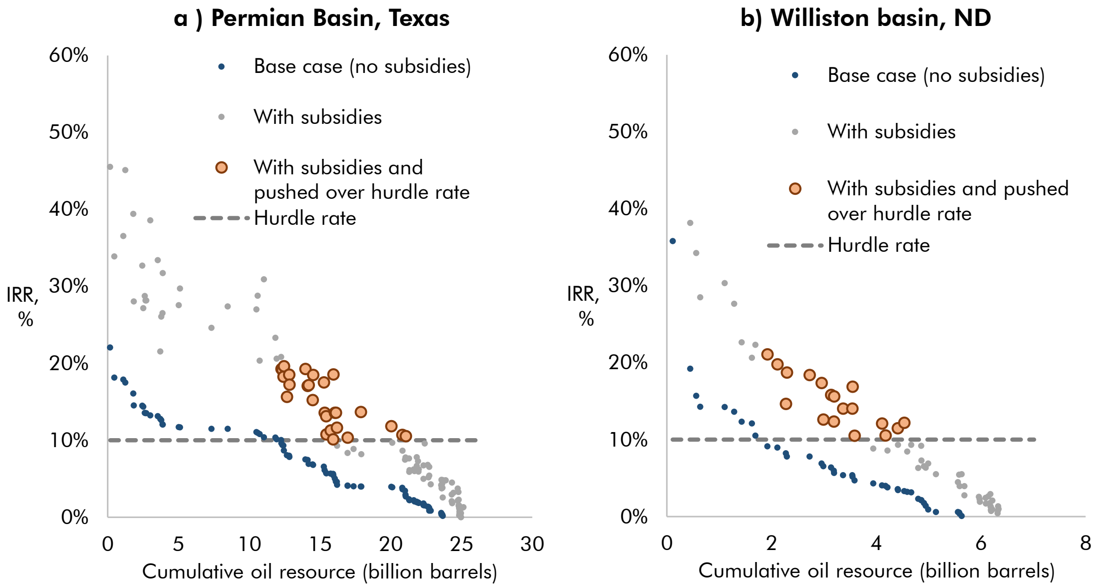
However, Figure 1a also shows that without the subsidies many projects in the Permian would not meet the 10% hurdle rate. These fields have small blue dots below the hurdle rate line, but corresponding larger red dots above it. Together, these projects account for about 8 billion barrels of oil. In total with subsidies, the Texas Permian contains 20 billion barrels of discovered, not-yet-producing oil that are economic at $50 per barrel. In this case, about 40% of the economic oil resource is subsidy-dependent.

Figures 1b and 1d show a similar pattern of subsidy impacts for the Williston basin and the rest of the U.S. Using a 10% hurdle rate, subsidy-dependent fields account for nearly 60% and 50%, respectively, of the economic, discovered but not-yet-producing oil resources in these basins.

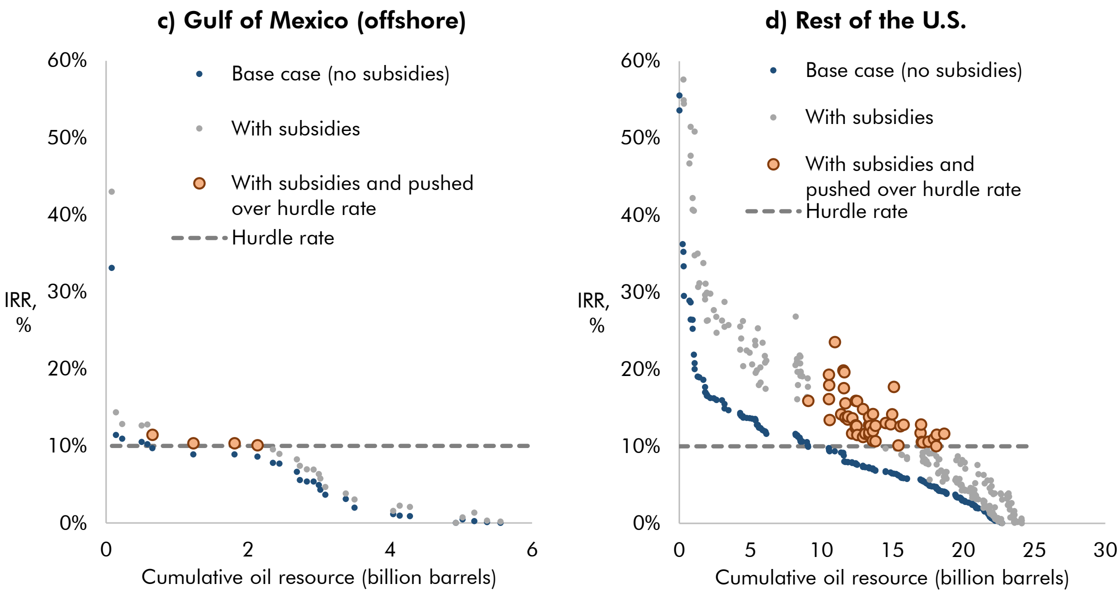
Likewise, Figure 1c for offshore oil in the Gulf of Mexico shows that more than 70% of the cumulative oil resource comes from subsidy-dependent projects. However, the economic drivers are different. The capital costs of offshore, mostly deep-water oil platforms are higher, but fewer of the producers meet Internal Revenue Service (IRS) definitions of an independent producer, so they do not qualify for some of the most generous subsidies. For these offshore projects, the fraction of fields that are economically attractive (even with subsidies) at $50 per barrel is much smaller. Indeed, our results for offshore oil are also the most sensitive to assumptions about hurdle rate and oil price. This is due both to the smaller number of offshore projects, and to the fact that many of the profitable ones are barely above the 10% hurdle rate.

Figure 1: Effect of subsidies on project economics at $50 per barrel, for fields discovered but not yet producing

These charts show the starting (before subsidy) and ending (after subsidy) IRR for the projects analyzed.[19] Each project is displayed as a single dot, ordered from highest starting IRR on the left to 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).



[19] The charts here show about 490 of the 800+ fields analyzed. About 320 never attain positive IRR at $50 per barrel, and have been excluded from the exhibits to enhance readability.



3.2 Sensitivity to oil price and hurdle rate

Figures 1a–1d display results for the current oil price of $50 per barrel. As noted, the impact of subsidies is highly sensitive to oil price, and that this sensitivity could have important policy implications. Figure 2 shows how the effect of subsidies varies substantially by price.

At very low oil prices (e.g. $30 per barrel, as displayed on the left side of the chart), 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. Most existing, already-producing fields would be able to cover their operating costs, however, and would continue to produce.

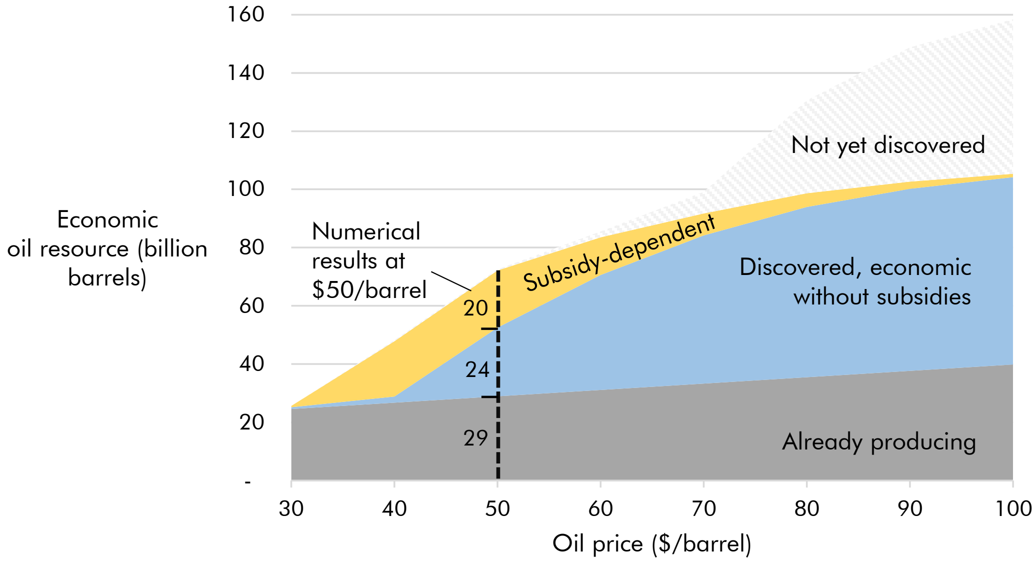
At $40 per barrel, new investment begins, even without subsidies. At $50 per barrel, investment in onshore fields takes off. At $60, investment in offshore fields begins to accelerate. At $100 per barrel, nearly all discovered fields would be economic: 40 billion barrels in already-producing fields, and more than 60 billion barrels in discovered but not-yet-producing fields. More speculatively, Rystad estimates that more than 50 billion barrels of not-yet-discovered fields could be economic at $100 per barrel, for a total of nearly 160 billion barrels of economic U.S. oil resource. Figure 2 shows each type of field in a different color, with subsidy-dependent fields displayed in orange.

Subsidies increase field development most strongly at lower prices. At $40 per barrel, almost all new investment would be subsidy-dependent. At $50 per barrel, as discussed above, nearly half (45%) of discovered fields – 20 billion out of 43 billion barrels – would be subsidy-dependent.

As prices increase above $50 per barrel, already-discovered fields become less dependent on subsidies. For example, if future oil prices rise to $80 per barrel and beyond in real terms, less than 10% of production from discovered, yet-to-be-developed fields would be subsidy-dependent. At $100 per barrel, a price level seen as recently as 2014 but which may not return until 2030, according to the EIA (2016b), subsidies might have very little effect on investment in currently discovered but undeveloped fields, or on the resulting oil resource available. Instead, nearly all of the subsidy value would go to extra profits. While subsidies can be structured to phase out at high market prices, the largest subsidies to oil do not. In fact, the percentage depletion allowance subsidy actually grows as oil prices rise.

Among the basins evaluated here, the greatest impact at $100 per barrel would be for offshore Gulf resources. This is because the region has the highest concentration of fields with high break-even costs.

Figure 2: Share of U.S. oil resources that are subsidy-dependent as a function of oil prices



Note: The chart assumes a 10% hurdle rate.

Figure 2 also displays (in grey hatching) Rystad's estimates of the U.S. oil resources that may still be discovered, most of which would cost $70 per barrel or more to develop.[20] These estimates are speculative, so we do not assess the fields' dependence on subsidies in detail here. 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.[21]

It is notable that industry dependence on subsidies increases at higher hurdle rates. If investors used a hurdle rate of 15%, rather than the 10% rate used for Figure 2, 25 billion barrels of oil (instead of 20) would be subsidy-dependent at $50 per barrel, and only 5 billion (instead of 23) would proceed anyway. Thus, the total proportion of subsidy-dependent production would rise to more than 80% at a 15% hurdle rate, compared with slightly less than 50% at a 10% hurdle rate. Appendix 1includes a version of Figure 2 using a 15% hurdle rate instead of 10%.

[20] These estimates include Rystad's assessment of the Midland Basin Wolfcamp shale. Recent estimates of that formation by the U.S. Geological Survey (USGS) indicate it could hold 20 billion barrels (https://pubs.er.usgs.gov/publication/fs20163092). This is about 14 billion barrels more than Rystad's (mid-2016) estimate. Should the potential be as the USGS estimates, this could increase the U.S. economic oil resource by about 10%. However, because the USGS still considers these resources *undiscovered*, including them here would not affect our findings on subsidy-dependent, already discovered resources.

[21] For example, should the same amount of oil resource be subsidy-dependent at $100 per barrel (due to new discoveries) as we estimate at $50 per barrel – 20 billion barrels – then 17% of the 120 billion barrels of not-yet-producing oil at $100 per barrel could be subsidy-dependent.

3.3 Effects on oil resources, production and CO_2 emissions

At prices of $50 per barrel, subsidies boost fields into profitability that contain an estimated 20 billion barrels of oil. Table 4 presents the scale of subsidy-dependent oil by basin, both in terms of barrels and as a share of each basin's resource base.

Although the absolute and relative quantities of each basin's subsidy-dependent oil varies, subsidies have a substantial impact in all of them. The impact in terms of barrels of oil is highest in the Permian Basin. The share of each basin's resource that is dependent on subsidies is highest in the Gulf of Mexico.

Table 4: Impact of subsidies on undeveloped oil resources and GHG emissions (at $50/bbl)

Area	Economic oil resources, discovered but not yet producing (billion barrels)	Percent subsidy-dependent	Increase in economic oil resources due to subsidies		Increase in net GHG emissions (Gt CO_2)
			(billion barrels)	(Gt CO_2)	
Williston basin	4.1	59%	2.4	1.0	0.2
Permian basin	20.3	40%	8.0	3.3	0.6
Gulf of Mexico	2.1	73%	1.5	0.6	0.1
Rest of U.S.	16.7	46%	7.6	3.1	0.6
Total U.S.	**43.3**	**45%**	**19.6**	**8.1**	**1.5**

Source: SEI analysis based in part on data from Rystad Energy.

Once burned, the nearly 20 billion barrels of subsidy-dependent oil would release about 8 billion tonnes (Gt) CO_2, as is also indicated in Table 4.[22]

Some further context on the relative scale of these emissions is helpful. The Intergovernmental Panel on Climate Change (IPCC) has estimated that if society is going to maintain even a two-thirds chance of limiting warming to the internationally agreed goal of 2°C (Clarke et al. 2014),[23] net global emissions from 2016 onward cannot exceed 840 Gt CO_2. In that context, the decision by the U.S. federal and state governments to continue subsidizing oil investment could produce oil that, once burned, will produce CO_2 emissions equivalent to about 1% of the remaining *global* carbon budget that all sectors of all economies.

It can also be helpful to compare this added production to the amount of oil that the U.S. might produce in a 2°C-consistent scenario. Some researchers have explored this question, using models that minimize the cost of meeting the global budget (McGlade and Ekins 2015; IEA

[22] We use "tonnes" to denote metric tons. To estimate CO_2 emissions, we use Rystad's assumed energy content of 5.51 MMBtu/ barrel and apply standard carbon contents of crude oil of 20.31 kg C / MMBtu from the EPA's national greenhouse gas inventory (U.S. EPA 2014).

[23] Here, we adjust the IPCC's 990 Gt CO_2 budget from 2012 to 2100 (IPCC 2013) by the CO_2 emissions that have been released in the four years since, or 150 Gt CO_2.

2015). 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 cost-minimizing models (McGlade and Ekins 2015; IEA 2015) suggest a cumulative carbon budget for U.S. oil production between 2016 and 2050 of 30 to 45 Gt CO_2. This range – which represents CO_2 emissions from combusting U.S.-produced oil – is likely on the high end, since it relies on scenarios that maintain only a 50–60% chance of meeting a 2°C target. It also omits important considerations, such as equity, that might suggest that a country with high relative wealth and a high proportion of historical CO_2 emissions would be expected to use a relatively smaller portion of any future carbon budget[24] (see, e.g., Kartha et al. 2016).

In summary, from a carbon budget perspective, subsidies may be responsible for up to a quarter (8 Gt of 30–45 Gt CO_2,) of the U.S. share of oil production through 2050 under a cost-efficient approach to limiting warming to 2°C (Table 5).

Table 5: Comparison of the potential CO_2 emissions from subsidy-dependent oil to global and U.S. carbon budgets

Resource	Quantity	Source	Notes
Subsidy-dependent new oil resource in the U.S., as of 2016	8 Gt CO_2	This study	Assumes price of ~$50 per barrel
U.S. carbon budget for oil production, 2016-2050	30 to 45 Gt CO_2	McGlade and Ekins (2015); IEA (2015)	Assumes 50 to 60% chance of meeting 2° C. For further details of U.S. oil production under a 2° pathway, see Erickson and Lazarus (2016)
Global carbon budget (all fuels), 2016-2100	840 Gt CO_2	IPCC (2013)	Assumes 66% chance of meeting 2°C; adjusted downward from ~1,000 Gt CO_2 in IPCC source to account for emissions since 2012

There is also another way to look at the effect of subsidy-dependent oil on emissions: the *incremental* effect on global CO_2 emissions. This other approach considers that adding nearly 20 billion barrels of oil to the global oil market may lead to less than 20 billion barrels of increased oil consumption, since the resulting small decrease in oil prices would also lead to less oil being produced elsewhere.

Using a simple model of the global oil market, as described in previous work (Erickson and Lazarus 2014; Erickson and Lazarus 2016), adjusted for the current outlook of global oil supply at prices around $50 per barrel, we estimate that about one out of every five barrels of new oil added to the market would be new, added oil consumption.[25] If that were the case, the nearly 20 billion barrels of subsidy-dependent oil would represent nearly 4 billion barrels of increased global consumption and 1.5 Gt CO_2 of increased global emissions (Table 4).

[24] We calculate this by extending the 2°C pathways reviewed in our prior work (Erickson and Lazarus 2016) linearly from 2040 through 2050 and integrating the total oil produced between 2016 and 2050.

[25] We use an elasticity of oil demand of -0.2 (Hamilton 2009) and an elasticity of oil supply of 0.87 (calculated from a cumulative 2016–2050 oil supply curve from Rystad Energy at $50 per barrel), such that Ed / (Ed-Es), which approximates the ratio of increased consumption to increased production, is 0.19.

Were the oil market to tighten, such as if other countries also removed producer subsidies or otherwise scaled back oil supply, the competition among producers could be greater (with a higher proportional decrease in oil prices). The effect on consumption would also be greater, with perhaps two-thirds of new barrels representing new consumption.[26] In that case, the incremental effect of subsidy-dependent U.S. oil on global CO_2 emissions could be 5.4 Gt CO_2.

3.4 Implications for oil industry profits

As noted above, to the extent that subsidies flow to fields that would proceed anyway, they represent a transfer payment from taxpayers to company profits, with little effect on near-term investment or production. Our analysis also allows us to estimate the fraction of overall subsidy amounts this subsidy "leakage" represents for each oil price level. At the price of $50 per barrel, we find that a bit more than half (53%) of subsidy value (in NPV terms) goes to projects that would have proceeded anyway. The share of subsidy value going to projects that are already profitable at $50 per barrel is highest in the Permian Basin, at 61%. The share of subsidy value going to projects already profitable at $50 per barrel is lowest for offshore Gulf of Mexico projects, at 26%, since fewer projects can proceed at this price level in that basin.

The fraction of support leaking to profits rises to nearly all (98%) of subsidy value at $100 per barrel. Our results across price levels echo what other researchers have found (Aldy 2013; Metcalf 2016): that regardless of the oil price, the majority of taxpayer resources provided to the industry end up as company profits.

3.5 Relative impact of different subsidies

As described in Section 2, this study differs from most earlier work in that it incorporates a much broader suite of subsidies. Figure 3 shows the incremental effect of the 12 subsidies evaluated using the average (production-weighted) impact on returns in the Permian Basin of Texas. Note that only 10 bars are shown because the two subsidies focused on offshore oil do not apply to this region. Across all fields analyzed in the Permian, our analysis indicates a production-weighted average increase in project IRR of more than 10 percentage points.[27] This can be seen by summing up all the blue and orange bars in Figure 3.

Similar to other research, we find that the immediate expensing of intangible drilling costs (IDCs) has the greatest effect on project IRRs. This subsidy boosts Permian Basin IRRs by nearly 7 percentage points on a production-weighted basis, for instance. Furthermore, other commonly discussed federal tax subsidies – percentage depletion and the manufacturers' 199 deduction – also affect IRRs by non-trivial amounts (at least three-tenths of a percentage point).

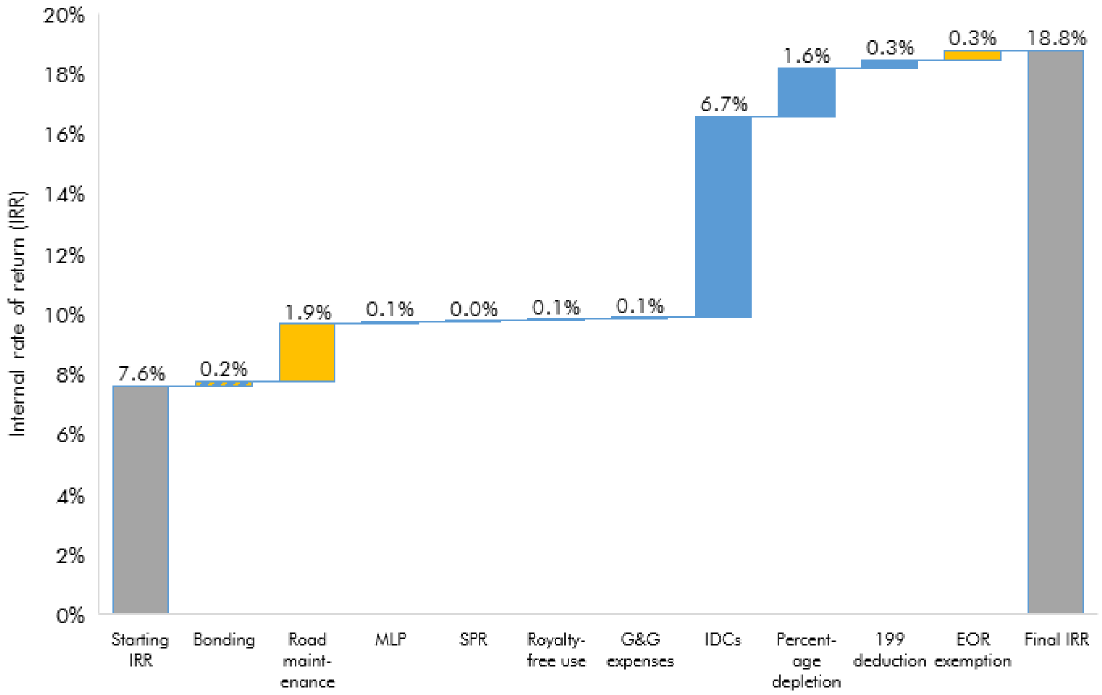
Another notable finding from our work is the importance of looking broadly at government supports to the oil sector, as less-studied subsidies also can have substantial effects, particularly when considered in combination. Three state subsidies in Texas – limited bonding requirements, government provision of road maintenance, and an exemption from the state severance tax for enhanced oil recovery (EOR) – illustrate this point. In combination, they are sufficient to increase IRR by more than 2 percentage points. At the federal level, only the IDC expensing is larger. It is clear that state policies also play a key role in influencing levels and

[26] Here, we instead use an elasticity of oil supply of 0.1, at the low end of an OECD review (Brook et al. 2004) and which we have used previously to characterize the oil supply market in a "lower-carbon world" (Erickson and Lazarus 2016)

[27] The median increase in IRR, as described earlier, is lower because there are a relatively large number of smaller projects that do not meet the 10% hurdle rate.

patterns of oil sector investment, and should be incorporated more fully into assessments of fossil fuel subsidy reform.

Figure 3: Average effect of each subsidy analyzed in the Permian Basin of Texas at $50 per barrel (average effect on a production-weighted basis across all fields)



4. CONCLUSIONS

For years now, the Obama administration and many members of Congress have sought to repeal subsidies for oil production. Most recently, the United States committed to the G20 to repeal these subsidies (U.S. Government 2015). Federal tax subsidies to the oil and gas industry alone – for example, the expensing of IDCs, percentage depletion, and the manufacturing deduction – cost U.S. taxpayers $2–4 billion each year (and would cost more if oil prices rise). Other researchers have estimated a fuller list of subsidies to oil and gas to cost nearly $18 billion per year. The limited number of academic studies to date have suggested that their repeal would offer a fiscal benefit without significant or "material" repercussions for oil production, consumption or GHG emissions (Aldy 2013; Allaire and Brown 2012; Metcalf 2016).

However, if oil prices stay relatively low, we find a very different outcome. Applying a number of key enhancements to prior studies – simulating the impact of a broader suite of state and federal subsidies on industry decision-making, using detailed field-by-field data, we find that, at prices between $30 and $70 per barrel, subsidies cause at least 10% – and up to 90% – of oil in yet-to-be-developed fields to go from unprofitable to profitable. At $50 per barrel, about half of yet-to-be developed oil is subsidy-dependent in this way.

Like prior studies, we too find that at higher prices ($80 per barrel and up), the strong majority of oil fields will likely be profitable and developed regardless of subsidy availability. At such prices, we also find the effects on U.S. oil production and global oil demand are likely to be modest. In this case, our study corroborates and builds upon prior work mainly by enhancing the resolution of the analysis to describe more specific results for major U.S. basins.

The share of subsidy-dependent production (of all new production) diminishes at higher prices for two reasons. First, because the overall amount of new production increases with price (denominator increases), more production is shifted to the left side of the charts in Figure 1 – i.e., production is attractive regardless of subsidies. Second, because more U.S. oil has been discovered with break-even costs close to \$50 per barrel than with break-even costs close to \$100, a small change in economics near \$50 affects many more new fields. And with that many more oil fields teetering on the boundary between being "go" and "no go" for investors, subsidies can make a much bigger difference when prices are relatively low.

It is possible that prices could return to levels of \$80 per barrel or higher in the coming years, as in "business-as-usual" projections by U.S. EIA and the IEA. As explained above, in that case the effect of U.S. subsidies on oil investment and production would be relatively modest, even as subsidies would represent a sizeable transfer payment from taxpayers to industry profits. Still, there are reasons to believe that prices could stay closer to \$50 per barrel for some time and, therefore, that a considerable fraction of new U.S. oil investment will remain subsidy-dependent. For example, in addition to its reference case forecasts, IEA also articulates a scenario in which a "new oil market equilibrium emerges at prices in the \$50-60/bbl range" (IEA 2015, p.153). This possibility is deemed to be likelier if other countries move to phase out fossil fuel consumption subsidies and the Organization of the Petroleum Exporting Countries (OPEC) and its allies continue to place a priority on market share instead of maximizing prices. Though OPEC agreed in late November 2016 to production cuts, questions remain about whether they will be substantial enough to keep prices well above \$50 per barrel.[28]

Oil prices in the \$50–60 per barrel range would also be likelier if major economies keep taking action to reduce greenhouse gas emissions and achieve the Paris Agreement's 2°C goal (Jaccard et al. 2016). Measures that have been adopted or are being 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 \$100 level on a sustained basis.

Our findings also highlight a major inconsistency in U.S. policy. Even while efforts have ramped up to reduce greenhouse gas emissions, government supports for oil production could be nearly doubling production. At prices around \$50 per barrel and assuming current oil market dynamics, this increase in oil production could translate into an incremental increase in global emissions of at least 1.5 Gt CO_2 cumulatively through 2050, working against U.S. and international efforts to reduce global emissions.

Such findings suggest an even stronger case for subsidy reform than has been articulated to date. Not only would removing federal and state support provide a fiscal benefit (which could instead be used for other purposes) and demonstrate U.S. compliance with existing G20 commitments, but the climate benefits could be substantial as well. These benefits come through lower oil production, oil consumption, and global CO_2 emissions, and could continue to expand if other countries followed in a similar path. The latter highlights another benefit: as

[28] For a discussion of some of the factors involved, see Faucon, B. and Amon, M. (2016). OPEC oil deal faces test as cartel tries to pin down russia on details of cuts. *The Wall Street Journal*, 9 December. http://www.wsj.com/articles/opec-output-deal-faces-its-first-test-1481279581.
See also Inman, P. (2016). OPEC doesn't hold all the cards, even after its oil price agreement. *The Guardian*, 4 December. https://www.theguardian.com/business/2016/dec/03/opec-oil-price-deal-doesnt-hold-cards-fracking.

others have noted (Aldy 2013; Metcalf 2016), phasing out fossil fuel subsidies at home could give the U.S. added leverage in prodding other countries to reform their own, often more significant fossil fuel subsidies.

With a new administration taking office, it remains unclear whether momentum for subsidy removal will be revived. Early statements from President-elect Trump indicate an intention to expand oil and gas drilling, suggesting an altogether different direction for federal policy, even as he also indicated an intention to eliminate corporate tax breaks. Regardless, a clear sense of the impacts of subsidy reform is essential to choosing the best path forward. With stronger evidence, a new Congress may be able to make progress where recent ones could not.

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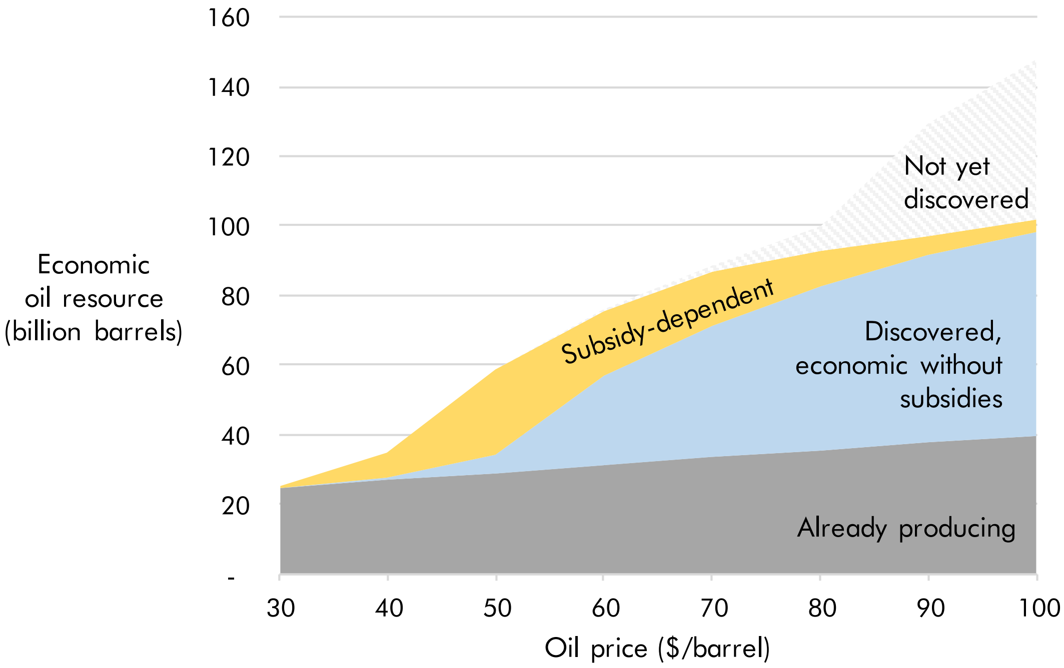
APPENDIX 1: ADDITIONAL RESULTS

This appendix presents two sets of additional results: U.S.-wide results at an alternate, 15% hurdle rate; and production-weighted average effects of each subsidy for the Williston and all-other-U.S. onshore fields (only the Permian was presented in the main text).

Results at 15% hurdle rate

Figure A1: Share of oil resources that are subsidy-dependent as a function of oil prices (15% hurdle rate)



Average effect of each subsidy, by basin

Figure 3 in the main body of this paper showed the average effect of each subsidy analyzed in the Permian basin at $50 per barrel. Charts for the Williston and rest-of-U.S. are included below.

Very few projects for offshore Gulf of Mexico are economic at an oil price of $50 per barrel, and the effect of subsidies is both immaterial and highly variable. As a result, we do not include a similar chart for that region. For the few projects that would be economic, intangible drilling cost deductions dominate the subsidy effects. At higher oil prices of $80–100 per barrel, where offshore Gulf of Mexico assets are more profitable, we find subsidies have a consistent impact of around 2 percentage points, again dominated by expensing of intangible drilling costs.

Figure A2: Average effect of each subsidy analyzed in the Williston Basin of North Dakota at $50 per barrel (average effect on a production-weighted basis across all fields)

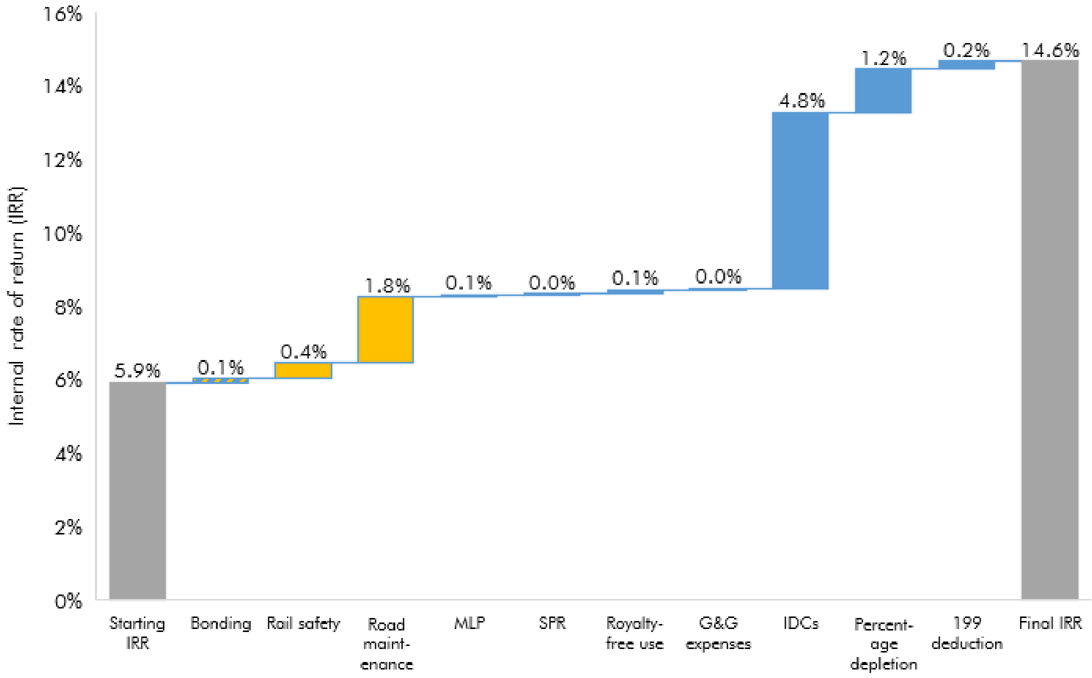
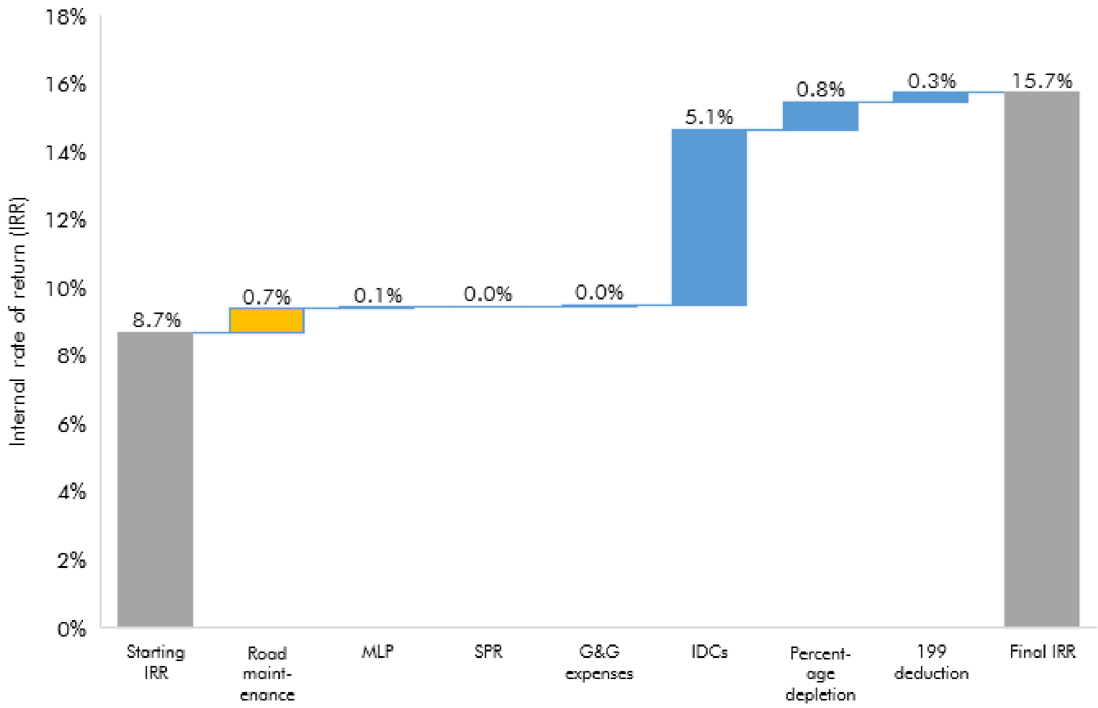


Figure A3: Average effect of each subsidy analyzed in onshore U.S. basins other than the Permian and Williston, at $50 per barrel (average effect on a production-weighted basis across all fields)



APPENDIX 2: DETAILED METHODOLOGY

As described in the main body of our report, 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 (2016). 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 (for tax provisions that accelerate depreciation) or operating costs (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 – 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. $50 per barrel, in real terms) to Rystad's estimated production curve for each asset.[29]

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

Overview of approach

All subsidies are modeled as modifications to the cash flow and production streams 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 license.[30] The data provided for each asset include, by year: oil and gas production, taxes and royalties, capital expenditures, and operating expenses. We consider assets that are under development or discovered but that are not in production as of 2016. We also 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, our analysis captures both oil and gas fuel streams and subsidies, however.

We calculate the effects of each subsidy in our model sequentially: that is, each subsidy modifies a cash-flow stream that includes the effects of any and all subsidies that have already been applied. In this way, any interactions among subsidies are automatically accounted for. In most cases, the sequence by which we analyze subsidy impacts does not matter. Subsidies that are simple per-barrel reductions in costs, for example, can be applied in any order. However, 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 (MLP) would have no effect if other subsidies had already eliminated any taxable income (e.g. 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 and applied to every field. To guide us, we first apply a simple ordering rule: we apply

[29] The price for the relatively small portion of natural gas produced at each field, if any, is assumed to be $15 per "barrel equivalent" in USD 2016 in all oil price scenarios (equivalent to $2.65 / mcf). We use a single gas price because the EIA's low and high oil price scenarios show that a tripling of the oil price correlates with much less of a change – 20% -- in the gas price.

[30] Rystad defines a field as "a project to develop a production unit to drain one or more pools in a formation, usually with well-defined ownership." Licenses are defined as "acreages the governments have awarded to E&P companies, where no oil and gas discoveries have been made yet." The distinction between field and license depends on context: "when a discovery is made, a field is created and the licenses will remain, representing the remaining exploration potential in the rest of the block".

the subsidies in an order approximating that in which they would be encountered 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, even before it is explored). This includes those related to requirements that any oil field developer will face (such as bonding or insurance) or necessary infrastructure (such as roads or rail needed to transport oil and equipment).

These are, in the order they are applied in our model:

- Under-market bonding costs;
- Insufficient liability insurance for spills;
- Public costs borne for transporting oil and equipment;
- Public costs for maintaining the U.S. Strategic Petroleum Reserve; and
- Reduced transport costs due to lower corporate income taxes for midstream companies organized as master-limited partnerships.

Since none of these costs directly depend on one 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 or 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 U.S. income tax form, i.e. Form 1120 for corporate income tax returns. So we first apply subsidies that affect income, then subsidies that affect costs (including deductions for depreciation or depletion), then subsidies that effect the actual tax rate paid.

These subsidies are, in the order they are applied in our model:

- Tax-free natural gas flaring and on-site use;
- Accelerated amortization of geological and geophysical expenses;
- Expensing of intangible drilling costs;
- Excess of percentage over cost depletion;
- Domestic production activities deduction; and
- State-specific tax modifications.

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"). But 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 the costs of developing an oil field are recovered over time for tax purposes. Before we go into detail about each specific subsidy, it is helpful first to discuss how we treat the capital expenditures upon which these tax subsidies depend.

Treatment of capital expenditures

Rystad's UCube provides capital expenditure streams for exploration, well drilling, and facility costs, as described in Table A1. 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. Because these three streams may have different tax implications – for example, exploration costs may be treated differently by the IRS as costs for building an offshore oil platform -- 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 (KPMG 2012). Table B-2 of IRS Publication 946 describes recovery periods for most classes of assets and the corresponding depreciation schedules (IRS 2015b), which for most assets is 7 years.[31]

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 themselves have no salvage value. These costs – sometimes called "intangible" – by contrast, are recovered through cost depletion (in the unsubsidized case), via immediate expensing as "intangible drilling costs" (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 (IRS 2015a).

Rystad does not estimate what fraction of capital expenditures are physical property or not, however. As a result, we use the approximations reported by Wood Mackenzie in their study for API (Wood Mackenzie 2013), as further detailed in Table A1.

[31] 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.

Table A1: 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 (Wood Mackenzie 2013) 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 (Wood Mackenzie 2013)

Methods for quantifying subsidies that reduce government revenue

This section and the ones that follow describe the assumptions used for modeling 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 US 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 US 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 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 (IRS 2015a). 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 (IRS 1996). 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 (Wood Mackenzie 2013).

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[32] and Rystad's estimates of the average number of wells per asset. Dividing the two yields an estimate of properties per asset.

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 (IRS 2015a). We assume that 10% of exploration expenses in Rystad's UCube are due to geological and geophysical costs and that independent producers elect to amortize these costs over two years.[33] Integrated operators instead recover these costs through standard cost depletion.

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[32] The number of wells per lease is based on the total number of wells divided by the total number of leases, as reported on http://drillingedge.com. Data for North Dakota is not available, so it is approximated using data from Montana, which also includes a portion of the Williston Basin.

[33] This is the average percentage of U.S. exploration and development costs classified as geological and geophysical between 1999 and 2009, the most recent data available (U.S. Energy Information Administration *Performance of Major Energy Producers 2009*, Table T-15: Oil and Natural Gas Exploration and Development Expenditures, http://www.eia.gov/cfapps/frs/frstables.cfm?tableNumber=15).

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 business are allowed to deduct 9% of their income from qualified production activities under this deduction, but businesses in the oil and gas sector are limited to deducting 6% of their income.[34]

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 (Master Limited Partnership Association 2016).

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 (2015) 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 (Master Limited Partnership Association 2016) 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.[35]

Royalty exemption for flaring and on-site use[36]

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 and the Outer Continental Shelf Lands Act of 1953 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 (Kendall 2010). 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.[37]

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[34] U.S. Internal Revenue Code Title 26 Section 199 "Income attributable to domestic production activities" https://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapB-partVI-sec199.pdf

[35] Our scaling is scaled based on the share of the U.S. intrastate trunk pipeline network dedicated to oil (45%) versus natural gas (55%) (Smith 2015)

[36] We categorize this subsidy here 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.

[37] *Dynegy Midstream Services v. Apache Corp.*, 294 S.W. 3d 164, 174 (2009)

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.[38] The rate of flaring in North Dakota is taken from Brandt et al. (2015). The rate of flaring in the Permian Basin per barrel of oil production is calculated based on Permian casinghead gas production[39] as a percent of Texas total casinghead gas production multiplied by statewide venting and flaring figures from EIA.[40] US offshore flaring per barrel of oil production estimated as total offshore flaring and venting divided by total offshore oil production, based on figures from the EIA.[41]

Texas crude oil severance tax exemptions

In addition to the federal support mechanisms discussed previously, 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.[42] 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 review. We estimate the volume of oil produced using EOR techniques in Texas using data from the National Energy Technology Laboratory (2010).

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

[38] This time period is the most recent 10 years for which these data are available.

[39] Permian casinghead gas is taken as the sum of casinghead gas from Texas RRC (http://webapps.rrc.state.tx.us/PDQ/generalReportAction.do) from districts 7C, 8A, and 08, following the Texas RRC's basin designation (http://www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/permian-basin)

[40] U.S. Energy Information Administration "Natural Gas Gross Withdrawals and Production" https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGV_mmcf_a.htm

[41] U.S. Energy Information Administration "Crude Oil Production" https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm

[42] See Table 9 of Texas RRC "Tax Exemptions and Tax Incidence" http://www.texastransparency.org/State_Finance/Budget_Finance/Reports/Tax_Exemptions_and_Incidence/incidence15/96-463_Tax_Incidence2015.pdf

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 (Ho et al. 2016). 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 Table A2.)

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 (Kaiser and Snyder 2009). 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.[43] This is likely to be a conservative assumption: very large firms in the coal industry *have* entered bankruptcy, shifting billions in reclamation liabilities to taxpayers.

[43] 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.

Table A2: 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).[44] 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[45], 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 (Mitchell and Casman 2011), 10,000 ft depths, and average well cost of $7.5 million.[46]	We assume annual premiums on surety bonds for onshore projects average 3% of the face value of the bond (Ferreira et al. 2003).
North Dakota	Producers may bond individual wells for $50,000 or up to six wells for $100,000.[47] 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[48], 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.[49] 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: in 2008 it averaged $1.24 million per lease (Kaiser and Snyder 2009).[50]	We assume reclamation costs average 10% of the costs of the platform (Borghini et al. 1998).[51]	We assume annual premiums on surety bonds for offshore projects also average 3% of the face value of the bond (Kaiser and Snyder 2009).

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.

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[44] Per http://www.rrc.state.tx.us/media/8216/bondi.pdf.
[45] Per https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.
[46] Per https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.
[47] Per http://www.legis.nd.gov/information/acdata/pdf/43-02-03.pdf.
[48] Per https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.
[49] Per http://www.boem.gov/uploadedFiles/BOEM/BOEM_Newsroom/Speeches/2013/RMMLF-Presentation-Williams-20130123.pdf.
[50] The BOEM has an online tool that appears to identify the specific liability for each lease: https://www.data.boem.gov/homepg/data_center/leasing/LeaseLiab/master.asp, plus a list of those that are exempt.
[51] This is roughly consistent with expected decommissioning costs of offshore oil platforms in the UK, averaging £81 million or $115 million per installation (Dunbar 2015). For a detailed treatment, see Kaiser and Pulsipher (2008).

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).[52] 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 (ICF/API 2014). 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.[53] This is interpreted as the residual liability borne by the public instead of by the rail car owners.[54] 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.[55]

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 (Edwards 2015). 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 (Pesanti 2016).[56] 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, and can be much lower (U.S. DOT 2009).[57]

There are at least four local and regional railroads operating in North Dakota that carry crude oil.[58] Increasing the coverage held by these railroads to the maximum available of $1.5 billion, at premiums of $25 per $1,000 of coverage (U.S. DOT 2009), would cost an estimated $130

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52 The NTSB supported tank car "Option 1" outlined by the Pipeline and Hazardous Materials Safety Administration (PHMSA) (https://www.regulations.gov/#!documentDetail;D=PHMSA-2012-0082-3460)

53 We calculate this based on Exhibit 5-3, Exhibit 4-4, and Exhibit 4-7 in a study by ICF for the American Petroleum Institute (ICF/API 2014).

54 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.

55 For example, tank cars involved in accidents in Mosier, OR in 2016 (http://www.oregonlive.com/environment/index.ssf/2016/06/5_ways_to_make_oil_trains_less.html) and Lynchburg, VA in 2014 (http://www.ntsb.gov/investigations/AccidentReports/Reports/RAB1601.pdf) were newer, CPC-1232 cars.

56 Possible damages to a hypothetical town of 170,000 people along one common rail route for North Dakota oil have been estimated as high as $6 billion (http://www.columbian.com/news/2016/jun/05/worst-case-scenario-vancouver-oil-disaster-could-cost-6-billion).

57 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 (http://www.timesunion.com/tuplus-business/article/Who-pays-if-a-crude-oil-train-crashes-No-6238612.php).

58 These are Dakota, Missouri Valley, and Western (DMVW); Northern Plains Railroad (NPR), Red River Valley and Western Railroad (all regional) and Yellowstone Valley Railroad (local). According to industry experts, short lines such as this "often" provide the first and last mile of crude oil transportation (http://transportation.house.gov/uploadedfiles/2015-02-03_-_rail_ssm.pdf).

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 (U.S. DOT 2009), 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.[59] 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 is already adequately covered by the existing Oil Spill Liability Trust Fund (OSLTF), to which producers contribute by paying a per-barrel fee.[60]

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 (King 2010). However, that level of insurance is not available in the marketplace. Following Murchison (2010), we therefore quantify the subsidy by assuming offshore producers be required to demonstrate insurance at the maximum amount of insurance *available*, which was recently estimated at $1.5 billion (King 2010), and as detailed in Table A3. Because actual damages (as with Deepwater Horizon) can be many times higher than $1.5 billion, benchmarking subsidies to available insurance coverage rather than actual risk will underestimate subsidy values.[61] 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 (U.S. EPA 2013), 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.

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[59] It is possible that rates 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.

[60] Whether producers of tight oil, such as that from the Bakken Formation, are actually paying the per-barrel fee on crude oil to contribute to the OSLTF or are claiming exemption due to the definition of "crude oil" is an open question that we do not address here (Ramseur 2016).

[61] 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 (http://www.ans.org/pi/ps/docs/ps54-bi.pdf). 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.

Table A3: 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[62]	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 (King 2010), following Murchison (Murchison 2010)	0.1% (Boyd 2001), 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.[63] 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 OECD (2015), 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.[64] The average subsidy estimate for this period is assumed to hold in future years, inflated at 2.5% annually, 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.[65] This yields a price of $0.07 per barrel in 2016 increasing 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

62 Per https://www.federalregister.gov/articles/2015/11/19/2015-29519/consumer-price-index-adjustments-of-oil-pollution-act-of-1990-limits-of-liability-vessels-deepwater.
63 See, for example, the U.S. Department of Energy's "History of SPR Releases," http://energy.gov/fe/services/petroleum-reserves/strategic-petroleum-reserve/releasing-oil-spr
64 See http://energy.gov/cfo/reports/budget-justification-supporting-documents.
65 Production data from the U.S. Energy Information Administration, https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.

costing approach (and more similar to the methodology OECD applied in years past) 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 (though more accurate) 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 (McCarthy et al. 2015). 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 $4 billion higher 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 (TxDOT 2012).

Building on approaches and findings in Texas, we estimate the cost of increased road maintenance 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 (Table A4).

Table A4: 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 $878,000 over lifetime of each well (Quiroga et al. 2012)	Current overweight fees from all trucks total about $111 million statewide annually (Prozzi et al. 2012). 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 road maintenance shortfall (TxDOT 2012)
North Dakota	Assumed same as above[66]	Assumed 3% of the marginal cost of road maintenance is collected as fees, same as above[67]

[66] 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) over a time (between 2007 and 2015) when 9,000 new oil wells (net) were brought online, per State of North Dakota statistics (https://www.dmr.nd.gov/oilgas/stats/historicaloilprodstats.pdf). 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, a figure that would only need to apply for 11 years in order to exceed the $878,000 lifetime cost assumed here based on detailed modeling in Texas.

[67] Overweight fees from all trucks in North Dakota increased $5 million (http://newsok.com/article/feed/394194) at a time when 3,500 new wells were brought online (https://www.dmr.nd.gov/oilgas/stats/historicaloilprodstats.pdf). Assuming half of these overweight fees were for trucks associated with the oil industry, and over an assumed 20-year life of each well, yields $14,000 in overweight fees per well, or also (as in Texas) about 3% of the road maintenance shortfall.

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 (Rusco 2008). The loss in tax revenue from this royalty exemption could be billions of dollars over the approximately 25-year lifetime of these wells (U.S. GAO 2008). 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.[68] 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 effects 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, its impact declines.

[68] See http://ww2.cfo.com/accounting-tax/2010/07/sucking-the-lifo-out-of-inventory.

APPENDIX 3: COMPARISON WITH OTHER STUDIES

There have been a number of attempts to evaluate the impact of subsidy removal on the US oil and gas industry in recent years. This section provides an overview of our research and results in comparison to the two other studies that are most like ours. The first was conducted by Wood Mackenzie on behalf of the American Petroleum Institute. The second was conducted by Gilbert Metcalf at Tufts University, and was published by the Council on Foreign Relations.

Comparison with Council on Foreign Relations study

This past summer, the Council on Foreign Relations published an analysis by Tufts University Prof. Gilbert Metcalf evaluating the effect of removing the three largest tax preferences on U.S. oil (and gas) production (Metcalf 2016). In aggregate, Metcalf found that removing the expensing of intangible drilling costs, the excess of percentage over cost depletion, and Section 199 domestic manufacturing deduction would reduce domestic oil drilling by roughly 9 percent. His results depend strongly on the elasticity of drilling activity with respect to price, a parameter value derived from actual oil market experience from 1990 to 2008. Over that period, the oil price varied within a fairly wide range – \$20 and \$100 per barrel. We believe his result of a 9 percent decline in drilling should be interpreted as the average effect that could be expected across this range of prices.

Our approach is somewhat different. Instead of using an average value for market response to price, we use estimates of field-by-field economics developed by Rystad Energy in its UCube database, which estimates the specific resources (location and magnitude) that would be economic (and therefore drilled) at each different price level. In its model, Rystad indicates that more resources have been discovered at each lower price band (e.g., between \$50 and \$55 per barrel) than at each higher price band (e.g., between \$100 and \$105 per barrel). Therefore, the oil "supply curve" steepens at higher prices, a pattern common in many oil supply curves, including the one developed by McGlade and Ekins (2015) that has been widely cited in analyses of future fossil markets. In elasticity terms, Rystad's curve has an elasticity of supply that is higher (~0.9) at lower prices and lower (~0.2) at higher prices. As a result, in contrast to Metcalf's findings, our results vary strongly depending on what oil price one expects for future markets.

The two analyses converge, however, at around \$75 per barrel – a level roughly equal to the average price, in 2016 dollars, of oil over the past ten years. At the \$75/barrel level, and using the same hurdle rate (15%) and subsidies analyzed by Metcalf, our work generates similar results: that about 9% of the oil resource across all field types (or, in Metcalf's analysis, "drilling"), would be dependent on subsidies (Table A5).

Table A5: Comparison of results from Council on Foreign Relations study (Metcalf 2016) with our own

		Metcalf finding on subsidy-dependent "drilling" (15% hurdle rate, price-independent)	SEI finding on subsidy-dependent "potential production" (at 15% hurdle rate, oil price as below)		
			$50/bbl	$75/bbl	$100/bbl
Onshore	Independent	8%	72%	7%	3%
	Integrated	5%	33%	22%	1%
Offshore	Independent	17%	--*	100%	50%
	Integrated	11%	--*	5%	26%
All		9%	69%	9%	5%

** No findings available because no offshore projects are viable at $50/bbl and 15% hurdle rate.*

By far the largest component of production in the Metcalf analysis is the onshore independent producers. For this important sub-category, the results at $75/barrel in our analysis closely match the Metcalf results: 7% in our study to 8% in Metcalf's study.

In contrast, the results for the other categories of oil differ markedly across the studies. This may in part be due to the greater uncertainty in our analysis for these other types of fields, given the smaller number of projects captured by the Rystad database. With a smaller sample, the subsidy dependence of just a few projects could have a greater effect on the percentage of projects that are subsidy-dependent. In addition, there are potential "kinks" in the supply curve where greater resource volumes may be either more dependent on subsidies (supply curve is flatter near the breakeven oil price) or less dependent (supply curve is steeper near the breakeven oil price). The shape of the supply curve in our study reflects estimates of actual oil resources and their associated breakeven prices, based on field-level assessments by Rystad. The flatter supply curve at $50 per barrel than at $100 per barrel indicates that there is simply less total oil economic to produce at prices $50 or below than what would be profitable at prices up to $100 per barrel. Thus, the same absolute quantity of subsidy-dependent production would yield a higher percentage of the total projected output at lower prices than at high.

Comparison with Wood Mackenzie study

In 2013, Wood Mackenzie, an extraction industry consultant, evaluated the effects of repealing the intangible drilling cost (IDC) provision of the U.S. tax code in a study published for the American Petroleum Institute. The most direct way to compare results between that analysis and ours was to focus on the fraction of new capital expenditures that becomes economic only due to the IDC in the Wood Mackenzie work to our estimate of potential production that surpasses its hurdle rate due to the IDC subsidy. Because the capital intensity per barrel is higher for offshore production than onshore, we have evaluated these categories individually in Table A6. Assuming that, in aggregate for each category, potential production is directly proportional to capex, these two quantities should be conceptually equivalent.[69] In this comparison, we also matched Wood Mackenzie input assumptions of $80/barrel for oil and a 15% hurdle rate. This allows us to segregate residual differences from the modeling approaches rather than those caused by differing input assumptions.

[69] Wood Mackenzie did not report results just for new fields, so we cannot make a direct comparison to our findings.

Table A6 shows how the results compare. For the onshore projects that comprise the strong majority of potential oil production in our study, we find that subsidies have a smaller effect than what Wood Mackenzie projected. Note, however, that the comparison is not perfect, because their study looked at new oil *and gas* drilling, whereas we look just at a subset of this: projects drilled primarily for oil (including the subsidies for gas production at those fields). It is notable that were one to adopt the higher estimates produced by Wood Mackenzie, estimates for the potential increase in production (and associated CO_2 emissions) would also be higher.

Table A6: Comparison of Wood Mackenzie findings with our own[70]

	Wood Mackenzie finding on subsidy-dependent capex for new oil and gas projects at $80 per barrel, 15% hurdle rate	SEI finding on subsidy-dependent "potential production" for new oil projects at $80 per barrel, 15% hurdle rate
Onshore projects	40%	18%
Offshore (Gulf of Mexico) projects	9%	25%

Source: Wood Mackenzie (2013); SEI analysis.

[70] Wood Mackenzie's analysis assumes a gas price of $4.50 per mcf; we employ a gas price of $2.65 per mcf in our analysis.

SEI - Headquarters
Stockholm
Sweden
Tel: +46 8 30 80 44
Executive Director: Johan L. Kuylenstierna
info@sei-international.org

Visitors and packages:
Linnégatan 87D
115 23 Stockholm, Sweden
Letters:
Box 24218
104 51 Stockholm, Sweden

SEI - Africa
World Agroforestry Centre
United Nations Avenue, Gigiri
P.O. Box 30677
Nairobi 00100
Kenya
Tel: +254 20 722 4886
Centre Director: Stacey Noel
info-Africa@sei-international.org

SEI - Asia
15th Floor
Witthyakit Building
254 Chulalongkorn University
Chulalongkorn Soi 64
Phyathai Road, Pathumwan
Bangkok 10330
Thailand
Tel: +(66) 2 251 4415
Centre Director: Niall O'Connor
info-Asia@sei-international.org

SEI - Oxford
Florence House
29 Grove Street
Summertown
Oxford, OX2 7JT
UK
Tel: +44 1865 42 6316
Centre Director: Ruth Butterfield
info-Oxford@sei-international.org

SEI - Stockholm
Linnégatan 87D, 115 23 Stockholm
(See HQ, above, for mailing address)
Sweden
Tel: +46 8 30 80 44
Centre Director: Jakob Granit
info-Stockholm@sei-international.org

SEI - Tallinn
Lai str 34
10133 Tallinn
Estonia
Tel: +372 627 6100
Centre Director: Lauri Tammiste
info-Tallinn@sei-international.org

SEI - U.S.
Main Office
11 Curtis Avenue
Somerville, MA 02144
USA
Tel: +1 617 627 3786

Davis Office
400 F Street
Davis, CA 95616
USA
Tel: +1 530 753 3035

Seattle Office
1402 Third Avenue, Suite 900
Seattle, WA 98101
USA
Tel: +1 206 547 4000

Centre Director: Michael Lazarus
info-US@sei-international.org

SEI - York
University of York
Heslington
York, YO10 5DD
UK
Tel: +44 1904 32 2897
Centre Director: Lisa Emberson
info-York@sei-international.org

Stockholm Environment Institute

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