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How subsidies aided the US shale oil and gas boom

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Key Messages

- **This study provides one of the first estimates of the extent to which federal government policy – in the form of three tax incentives – increased the expected value of investments in new, unconventional oil and gas developments in the US over the last two decades. Expected value was calculated as the estimated net present value at the time of the investment decision.**

- **Two tax incentives alone – the expensing of intangible drilling costs and percentage depletion provisions – increased the expected value of new oil and gas projects by billions of dollars in most years, and over $20 billion in some high-price years. This translates to a median increase in expected value of $4 per barrel of oil equivalent or more across projects in such high-price years (2008 and 2010-2014).**

- **These two subsidies added substantial value to new unconventional oil and gas projects considered in the Bakken formation in 2005-2006, the Appalachian and Haynesville regions in 2008, the Eagle Ford play in 2009-2010, and the Permian basin in 2011-2015, thereby helping to spur and sustain the US shale boom over the last two decades.**

Introduction

President Biden has indicated, both during his presidential campaign and once in office, that he would like to see the United States (US) end its subsidies to fossil fuel producers. Subsidies to fossil fuels can lower the costs of these polluting forms of energy, making it more difficult for low-carbon sources to compete. In the words of G20 governments, subsidies to fossil fuels "undermine efforts to deal with climate change" (G20, 2009).

In a 2015 self-assessment submitted to the G20, the US federal government identified 16 federal tax measures that amounted to around $4 billion per year of fossil fuel producer subsidies (U.S. Government, 2015). Other analyses that include a wider list of subsidies have put the figure higher, at about $15 billion per year (Redman, 2017).

Three subsidies to oil and gas exploration and production dominate the US government's own tally of fossil fuel subsidies. These are the accelerated amortization period for geological and geophysical (G&G) expenses, the expensing of intangible drilling costs (IDC), and the use of percentage depletion for oil and gas wells. Together, these three subsidies comprise about $3 billion per year of the approximate $4 billion total.

The US has modified the IDC and percentage depletion provisions over time, generally to reduce their value. However, these subsidies have now been around for about a century. They have affected oil and gas well drilling, investment, and production levels in the past (Cone & et al., 1980) and may continue to do so in the future, at least when long-term oil and gas prices are relatively low (e.g., under about $60/barrel for oil, and under about $4/MMBtu, or million British Thermal Units, for gas) (Achakulwisut et al., 2021; Erickson et al., 2017; Metcalf, 2018). At the same time, much of the value of the subsidies goes directly to extra, "super normal" profits – especially when oil and gas prices are relatively higher. These extra profits are over and above the "normal" profits required to make each project economically viable (such as an investment return of 10%), and therefore play relatively little role in job or infrastructure creation (Aldy, 2013; Erickson et al., 2017).

The debate over subsidy reform has not generally explored which companies, types of oil and gas drilling, and regions of the country have benefited most from subsidies. This lack of clarity is mostly because neither the companies themselves nor the US government (e.g. the Internal Revenue Service, who administers these tax subsidies) provide such detailed information. A clearer sense of who has benefitted from the subsidies could be useful to reform efforts in the months and years ahead.

In this paper, we develop a financial model to analyze how three subsidies – the accelerated amortization period for geological and geophysical expenses (G&G), the expensing of intangible drilling costs (IDC), and the use of percentage depletion for oil and gas wells – affected the economics of oil and gas production in the US over the past two decades. Specifically, we estimate how much these subsidies increased the expected project value (i.e. net present value at the time of the investment decision) for different firms and regions. Where possible, we also estimate when and where the three subsidies potentially made the difference in a new oil or gas field being developed. This information can be used by policymakers to better understand the beneficiaries and impacts of these subsidies and, in turn, assess the advantages and disadvantages of these outcomes.

We estimate that these three federal subsidies increased the total expected value of all new projects developed over the last two decades by billions of dollars in most years, and over $20 billion in some high-price years. The majority of this subsidy value went to new oil and gas fields being developed from unconventional formations.

Our estimates depend on our underlying analytical assumptions. Because we do not have access to the actual tax records for individual companies, we cannot definitively determine who received how much benefit, or, in turn, how those subsidies changed decision-making. Instead, our estimates are based on applying a standard financial decision-making model to historical data, and therefore provide one reasonable means of evaluating – based on actual historical production and investment – how subsidies may have affected prospective investment returns and played a role in the decision to proceed with drilling.

How subsidies affect oil and gas well profitability

Over the last three decades, tens of thousands of new oil and gas wells have been drilled each year in the US. Wells have been drilled in Texas, in newly developed areas in Pennsylvania and Ohio, in dozens of other US states, and in the federally administered regions of the Gulf of Mexico. Altogether, the boom of well drilling in the last fifteen years – which peaked in 2007 at nearly 50,000 wells (Patel & Geary, 2020) – has, along with well productivity improvements, led to the US becoming the world's largest oil and gas producer (BP, 2020).

How a firm decides when and where to drill new wells is subject to many factors. In the early stages, when firms are deciding which lands or permits to purchase, the considerations are often strategic, such as the potential benefits of getting a toehold in a new market, or the risks of exploring in a new area (Jahn et al., 2008b). Once sufficient information is available about the underlying geology, however, firms then tend to make decisions based on financial metrics of profitability. These metrics often use discounted cash flow analysis, a common technique for assessing prospective investments (Bailey et al., 2000; Jahn et al., 2008a; Zhou et al., 2021), though more complicated decision-making frameworks may also be employed.

Government support for oil and gas can play a role in encouraging development at each stage of the process. In the US, for example, the federal government allows oil and gas exploration and development on public lands, including in offshore waters in the Gulf of Mexico, in a way that has been found to undervalue the resource and, therefore, fails to provide a fair return to the public (Rusco, 2019). During the drilling and construction of oil and gas wells (and regardless of whether the land is public or private), the government allows firms to postpone and reduce their tax obligations using the intangible drilling cost (IDC) expensing provision. Later, during production, the government allows some firms to deduct from their taxable income an arbitrary, fixed percentage ("percentage depletion") of their revenue. After the wells are closed, federal and state governments may even assume responsibility for cleaning them up.

In addition to these tangible examples, government support for the fossil fuel industry can also have more symbolic effects, since government statements and subsidies can send messages that the

activities of the oil and gas industry are beneficial for society. Such messages can help smooth the way for new oil and gas developments, reducing risks and encouraging further investment (Erickson et al., 2020).

Methodology of this study

Adding up all the ways that the US government supports oil and gas, and understanding how that affects investment and production levels, is a complicated exercise. A few efforts have attempted to look at subsidies for a select group of new, not-yet-developed oil and gas fields (Erickson et al., 2017; Krueger, 2009; Metcalf, 2018). But even fewer studies have attempted to look backwards, and gauge how subsidies had an impact in the recent past.

This paper makes a first attempt at such a retrospective analysis. Our aim is to see, in the rear-view mirror, how the three largest subsidies identified by the US government may have created value for firms and, in turn, affected investment levels over the past two decades.

To conduct this analysis, we rely on data compiled by Rystad Energy, an independent energy research and consultancy company (Rystad Energy, 2021). Specifically, we analyze the production and costs (including capital investment) data of 2,450 oil and gas fields that started producing between 1998 and 2019. We chose this time period because it includes the previous oil market low in 1998 ($13/barrel), through the all-time high in 2012 ($112/barrel), and subsequent decline and fluctuations thereafter up until recent years (US EIA, 2020).

For each field, we estimate how the three subsidies affected the *expected* value of investments in its "decision year". Two important assumptions underpin this estimate of expected value. First, we calculate the value assuming the prevailing oil and gas prices at the time. We do so because the best estimate of future oil and gas prices is generally the current price (Hamilton, 2009) and, in any case, it is not possible to know exactly what price forecasting method each firm used. Second, we assume the responsible firms had accurate information about how much oil or gas would be produced from each field.

Using these assumptions, for each field, we conduct the discounted cash flow analysis from the perspective of an investor about to make the decision *in that historical year* whether to proceed with developing new oil or gas fields. To estimate this decision year from Rystad's raw data, we assume this decision occurs in the first year that capital expenditures exceed $1 million for offshore fields and $0.5 million for onshore fields. For onshore fields in which annual capital expenses never exceed $0.5 million, we use the year prior to when production first starts. These thresholds are imperfect, but were defined to yield an algorithm that generated a reasonable decision year that was not affected by small capital expenditures unrelated to the initial, substantial build-out of a field. (See Appendix for further details on our methodology).

Figure 1a shows when each of the 2,450 fields analyzed received their go-ahead decisions according to our model. As shown, firms approved new fields at a faster rate when oil prices were high in the 2008-2013 period, and at a slower rate since the oil price crash of 2014. One observation about these fields immediately stands out: "unconventional"[1] oil and gas fields went from less than half of new fields in 2006, to more than half in 2007, and have since dominated new field development. This transition was due to the development of horizontal drilling and hydraulic fracturing technologies that rapidly displaced conventional well drilling practices over this period (Wang & Krupnick, 2015).

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1   Here, we follow Rystad's classification of "Unconventional Group", which is defined as follows: (1) Conventional refers to conventional reservoirs (i.e. good permeability), conventional hydrocarbons (i.e. not extra heavy crude) or conventional recovery methods (i.e. not hydraulic fracturing); (2) Unconventional is defined as extraction from continuous accumulations of hydrocarbons, including oil sands, extra heavy oil and tar sand, shale gas and shale oil, very tight reservoirs, and coalbed methane.

Figure 1. a) Number of oil and gas fields developed in each decision year in the US, overlaid by historical oil and gas prices (in nominal USD per barrel of oil equivalent, or "boe"); b) Total capital expenditures (CAPEX) associated with the fields developed in each decision year (billions of nominal USD). (Note: USD/MMBtu = USD/boe ÷ 5.8.)

a) Number of new fields by decision year

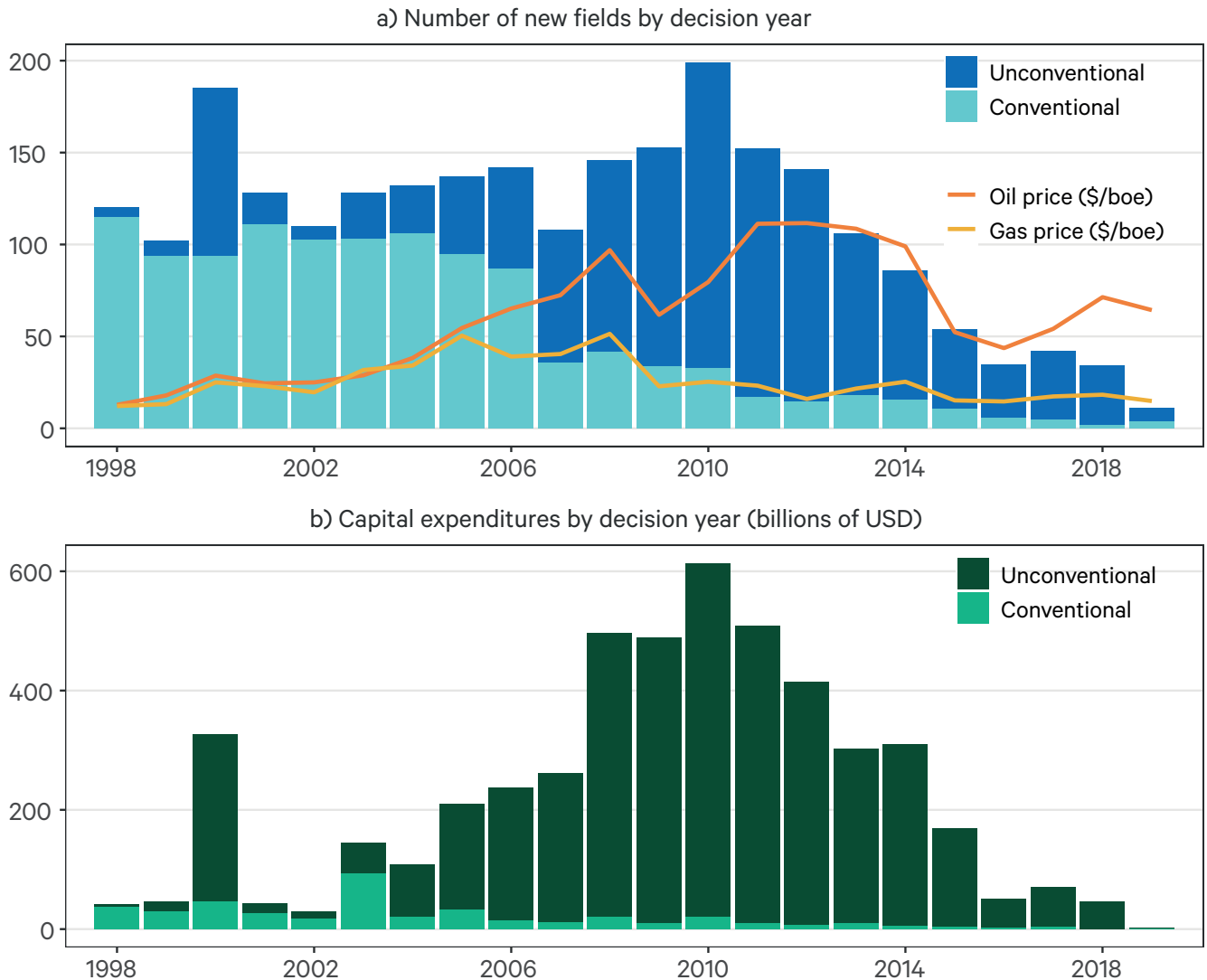## b) Capital expenditures by decision year (billions of USD)

Figure 1b shows the cumulative capital investment associated with the fields that were given the go-ahead for development in each year. This is the cost of exploring, drilling, and developing each oil and gas well, plus any on-site facilities, over the eventual lifetime of each field. For example, for the 153 fields developed in 2009 (Figure 1a), Figure 1b shows that the total capital invested in those fields was expected to be nearly $500 billion, or over $3 billion on average per field. (Note that, of course, not all of the fields' oil and gas wells were drilled in that year – i.e. this capital was not all invested in 2009.)

Together, Figures 1a and 1b provide an important context for our analysis. By analyzing how subsidies aided the development of new oil and gas fields over the last two decades, we are also analyzing how subsidies aided the deployment of new unconventional oil and gas extraction techniques, especially from 2004 onwards. The earlier spike in 2000 reflects the beginnings of oil and gas production from unconventional US formations centered in Texas and New Mexico, as the Permian Basin started to transition from conventional to unconventional oil production (Scanlon et al., 2017), and as the nearby Barnett shale play was successfully developed by Mitchell Energy and Development Corporation for gas production (Hinton, 2012; Wang & Krupnick, 2015).

Subsidies boosted expected returns

Our study finds that each of the three subsidies analyzed boosted industry financial metrics at the time of the investment decision in different ways. Before describing our results, we first discuss how each subsidy generally acts on company cash flow and, in turn, affects decision-making. All three subsidies work by reducing the tax payments that the firms owe, in ways that are targeted to the oil and gas industry. (That is what makes these tax measures subsidies: they are financial benefits not generally available to other industries). We describe each subsidy here in the order in which they would be encountered during the process of developing a new oil or gas field.

First, the accelerated amortization period for geological and geophysical expenses is a subsidy because it allows these expenses to be deducted faster than they otherwise would be under standard amortization schedules. Geological and geophysical expenses are primarily incurred during exploration for new oil and gas and, before 2005, were recovered in tax filings over the life of an oil or gas well (Joint Committee on Taxation, 2009). From 2005 onwards, independent companies have instead been able to recover these costs over two years – the year in which the costs were incurred, plus the year after (a time period much shorter than the life of a well) – thereby reducing, or at least deferring, their tax liability. This boosts investor returns on a present-value basis. Note that, since we are evaluating each field only from the perspective of the decision year to proceed with drilling, we are by definition excluding the geological and geophysical expenses that are incurred before the decision year, and are therefore not able to capture the full value of this subsidy.

Second, the expensing of intangible drilling costs (IDC) subsidy acts in a similar manner as the geological and geophysical (G&G) subsidy, but for a much larger class of capital expenses: well drilling and construction. These expenses typically peak around 6 years after unconventional (e.g. fracked) field development begins (and typically within the same year for conventional fields), with production peaking a few years thereafter. Intangible (meaning, no salvage value) drilling costs for oil and gas wells are the dominant type of capital investment for oil and gas production operations (Wood Mackenzie, 2013). Therefore, how these expenses are treated in the tax code can have a dramatic effect on field cash flow and, by extension, profitability. Currently, independent firms (those with retail sales less than $5 million or which do not refine more than a daily average of 75,000 barrels of crude oil) can deduct all IDCs immediately, whereas integrated firms (those that exceed those thresholds) can deduct 70% of IDCs immediately, with the remaining costs amortized over a five-year period (Joint Committee on Taxation, 2009). This immediate or accelerated deduction (rather than over the life of a well) again allows firms to lower their taxable income, freeing up cash flow and increasing profitability (Metcalf, 2018). Independent firms have developed and produced between 80% and 90% of oil and gas over the last two decades (Rystad Energy, 2021), and so most extraction activities are eligible for the IDC.

Lastly, the percentage depletion subsidy allows independent firms to deduct on their taxes 15% of the gross value of oil and gas production (up to 1,000 barrels per day of crude oil or the equivalent amount of natural gas), rather than make deductions based on the actual capital invested. Accordingly, percentage depletion can inflate the overall amount of the deduction to levels greater than the actual capital costs incurred, essentially providing free income to the producer for the life of the well. Even when originally introduced in Congress, the level of percentage depletion allowed was considered "arbitrary" (Joint Committee on Internal Revenue Taxation, 1927), and it has long been considered one of the most egregious subsidies to the oil and gas industry, allowing them to deduct "imaginary" costs (Hassett, 2012). While limits have been put on the use of percentage depletion over time, it remains an important subsidy to independent oil and gas firms in the US (U.S. Government, 2015).

In our analysis, we model the baseline "with-subsidies" case for each oil and gas field using the historical stream of capital costs, operating costs, and production data provided by Rystad

Energy. The "without-subsidies" cases are then constructed by sequentially modifying the baseline conditions to reflect the effects of the removal of each subsidy, one after another. Further details on how these subsidies were modeled are provided in the Appendix.

Figure 2. Estimated effect of each subsidy on expected net present value of all new oil and gas fields first developed in each decision year between 1998-2019 (in billions of nominal USD). Calculations of net present value assume a 10% nominal discount rate. (Subsidy abbreviations are as follows: "IDC" = expensing of intangible drilling costs; "G&G" = accelerated amortization period for geological and geophysical expenses. Note: USD/MMBtu = USD/boe ÷ 5.8.). Note that the value of the percentage depletion subsidy in early years is likely too low in our analysis because our model appears too pessimistic about likely future revenues (and therefore the value of this subsidy) of fields that were given the green light for development in these early years. Our estimates also do not capture the full value of the G&G subsidy, since our model excludes the geological and geophysical expenses that are incurred before the decision year. See Appendix for further details.

Estimated increase in expected value by subsidy (billions of USD)
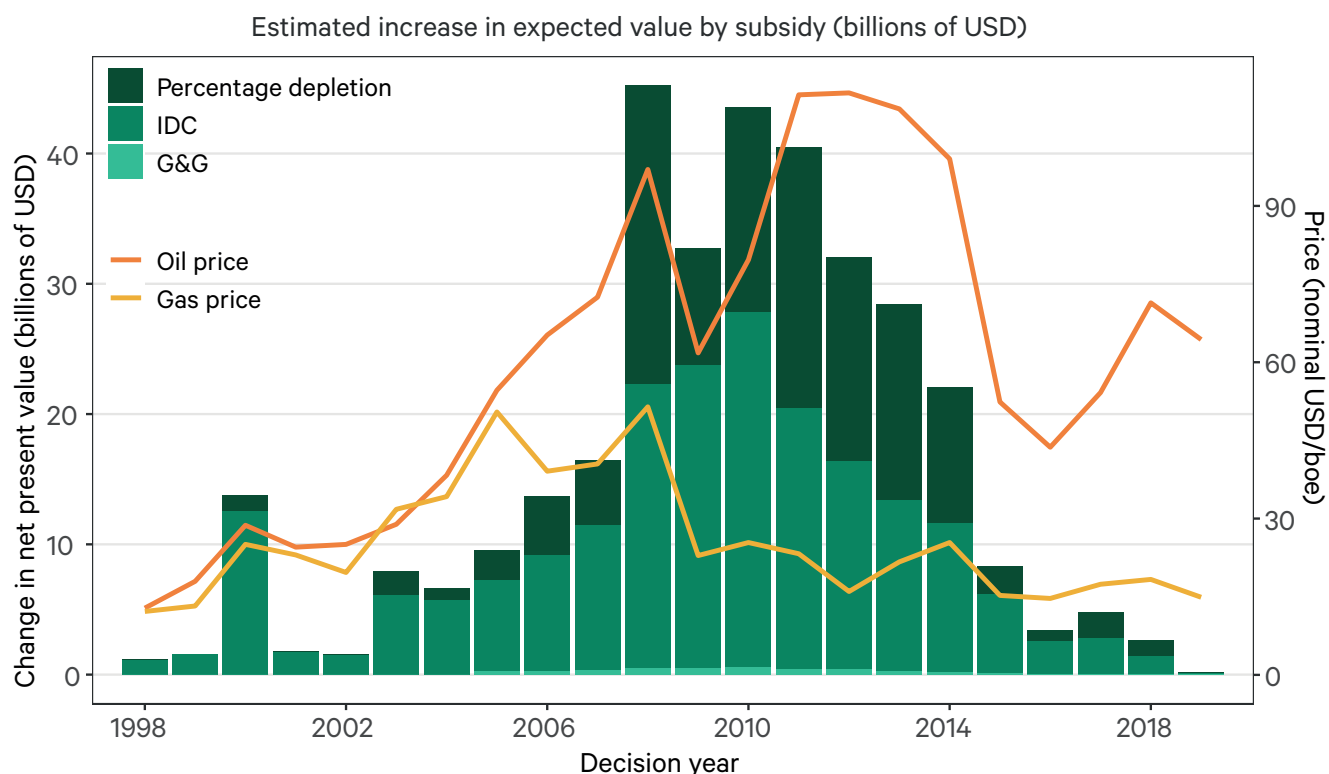
Together, as shown in Figure 2, the three federal subsidies are estimated to have increased total expected value (technically, estimated net present value at the time of the investment decision) by billions of dollars in most years over the last two decades. In 2009, for example, Figure 2 shows that the total value of subsidies to the firms was over $30 billion for the approximately 150 fields that were given the green light for development (Figure 1a). In other words, the net present value of developing these 150 fields was expected to be $30 billion *more* with subsidies than if the subsidies had not been in place. This translates to a median increase of about $4 per barrel of oil equivalent (oil and gas combined) across the 150 fields – a substantial value when oil prices averaged $62/barrel and gas prices averaged $4/MMBtu ($23/barrel of oil equivalent) in that year (see Figure S1).

These values are considerably higher than the US government's own estimates of these three subsidies; for example, the government estimated they were worth $2 billion in 2009, less than one-tenth as much as our model shows (OECD, 2018). The US government's estimate simply evaluates the aggregate change in tax payments in each year (with little or no consideration of how money is more valuable if available sooner rather than later), which, though a common method for evaluating tax "expenditures" for each year (Joint Committee on Taxation, 2009), misses how subsidies provide value to oil and gas drillers (Metcalf, 2018).

By contrast, here we evaluate the expected net present value to the companies themselves, taking into account firms' time preferences for how they value money. Namely, the oil and gas industry values delaying its tax obligations much more so than the US government appears, at least in official records, to mind the delay in receiving taxes.

As shown in Figure 2, the IDC subsidy is the largest subsidy in most years. The value of this subsidy arises because it allows firms to speed up their tax deductions by continuing to invest in new oil and gas wells. A firm's discount rate (a measure of how much less an entity values money a year from now, compared to having it today) is generally much higher than the US government's discount rate; our paper and Rystad assume a firm's discount rate is 10%, while, in 2009, the government's was far less than 1%, as judged by the value of US Treasury Bonds. Consequently, the delay in tax liability is much, much more valuable to the firm on a net present value basis than it might otherwise appear.

Subsidies helped to spur the US shale boom

In a 2015 review paper, Wang and Krupnick (2015) discussed how a number of key factors – namely, technological innovations, government policy, private entrepreneurship, private land and mineral rights ownership, and high natural gas prices – converged in the early 2000s to enable the US shale gas boom. The authors wrote that "for a real boom to occur in the private sector, high profitability, or at least the expectation of future high profitability, is a necessary ingredient". However, as they also noted, no study has yet rigorously examined the impact of financial incentives provided by the US government.

Our study provides a view into this "expectation of future high profitability" noted by Wang and Krupnick. Specifically, our findings provide one of the first estimates of the extent to which federal government policy – in the form of three major tax incentives – increased expected value and reduced the risk of investments of new, unconventional oil and gas developments in the last two decades. Figure 2 showed that the IDC subsidy, followed by the percentage depletion provision, were likely to have been highly beneficial. In Figure 3, we show the increase in expected project value disaggregated by region and development type.

The timing of the large increases in expected project value shown in Figure 3 coincide with, and are driven by, the beginnings of unconventional oil and gas developments in different regions throughout the US. For example, the increases in expected values shown in Figure 3 reflect the shale oil boom in the Bakken formation in North Dakota in 2005-2006; the shale gas booms in the Appalachia and Haynesville regions in 2008; and the booms in the Eagle Ford shale play in 2009-2010 and the Niobrara shale play in 2010-2011 (Maugeri, 2013; Wang & Krupnick, 2015).

Similarly, from 2011 to 2015 (along with an earlier spike in 2000), the subsidy-induced increases in expected project value were primarily concentrated in the Permian Basin, a basin in the southwestern US that was the epicenter of the country's shale boom. The spike in 2000 coincided with the start of the transition of the Permian basin from conventional to unconventional oil production (Scanlon et al., 2017). Major developments in 2011-2015 include those located in the Wolfcamp, Spraberry, Bone Spring, and Delaware shale/tight formations. Cumulatively, the Permian saw the greatest increase in expected value (over $100 billion across all years in Figure 3), followed by the Appalachian region (about $50 billion across all years in Figure 3). (Note: see Figure S2, page 15, for a map of the locations of major unconventional oil- and gas-producing regions.)

The main reason that the subsidy values shown in Figure 3 primarily went towards new *unconventional* developments is simply because they were dominating the types of new projects, as shown in Figure 1. Nevertheless, it also appears that the subsidies may have disproportionately benefitted unconventional compared to conventional projects. For example, in the years 2006 and 2007, when oil prices were rising and the number of new unconventional fields being developed

Figure 3. Estimated increase in expected net present value (in billions of nominal USD) – due to the three subsidies analyzed in this study – of new oil and gas fields first developed in each decision year between 1998-2019, by region and type of development. Regions are plotted in order of decreasing value across all years from bottom to top (i.e., the Permian is the largest between 1998-2019). (see Figure S2 for a map of region locations in the US). As described in the caption to Figure 2, the values in early years (e.g. pre-2005) are likely artificially low because of pessimism in our model.

Estimated increase in expected value by region (billions of USD)
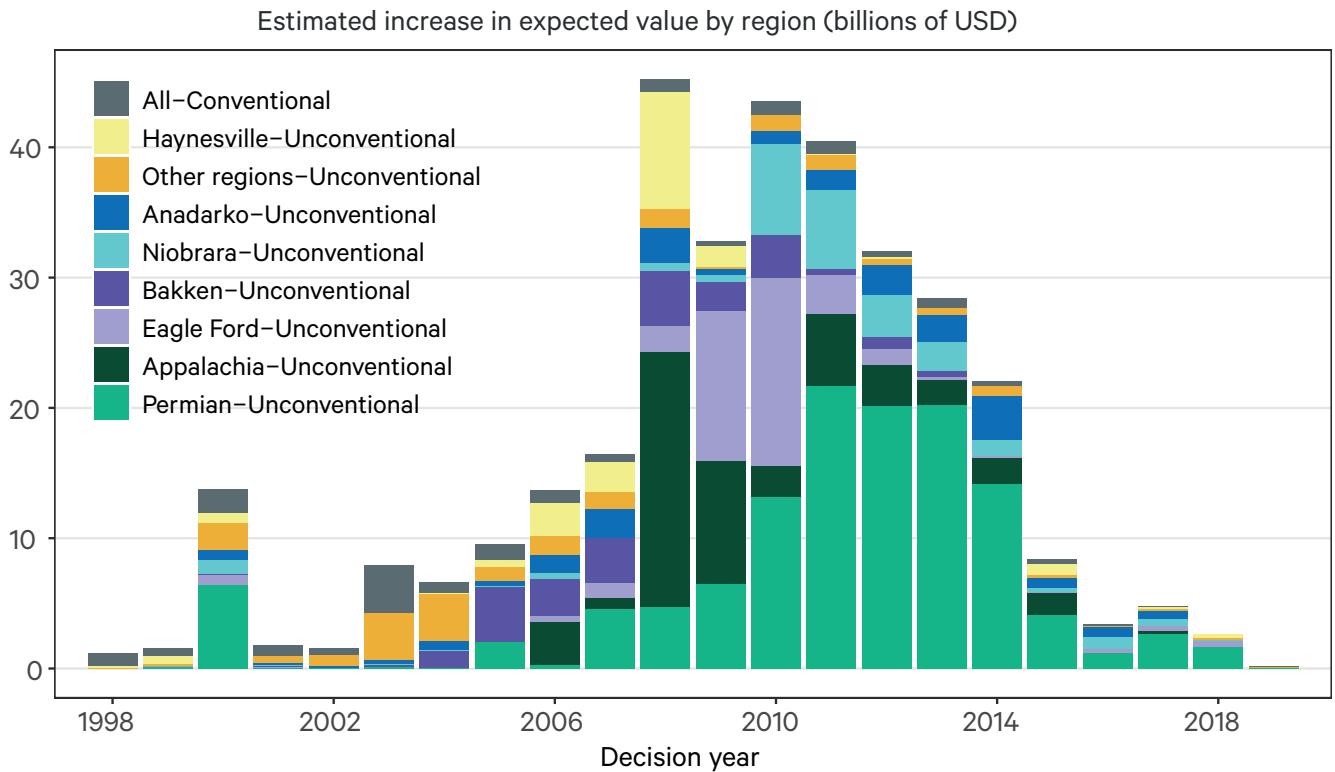
first overtook those for conventional fields (Figure 1), the median benefit to unconventional fields was, on a levelized basis, about $5 per barrel of oil equivalent (boe), more than double the $2/boe for conventional fields. This may be a result of the fact that unconventional wells generally cost more than conventional wells ($6 million to $8 million per well, compared to $2 million, respectively) (U.S. EIA & IHS Global, 2016). Therefore, subsidies tied to capital investment, like the IDC subsidy, could provide more of an incentive for unconventional drilling. Future research could explore in more detail to what extent subsidies disproportionately benefited unconventional drilling or, by contrast, whether the faster production decline rates of unconventional oil wells may end up muting or counteracting this effect (Metcalf, 2018).

Some firms likely benefitted more than others

As previously described, the US tax code provides the most generous subsidies for independent firms, even as integrated firms also benefit, especially from the IDC subsidy. To explore which firms may have benefited the most from subsidies, Figure 4 shows the estimated value of subsidies broken down by firm, for the 15 firms that we estimate received the most benefit (measured as the increase in expected project value over the period of our study, and assigning benefits based on the company or companies that owned a given field in the decision year).

As can be seen in the figure, the estimated subsidy value is especially concentrated in a few firms in certain years.

For example, we estimate that in the decision year of 2008, subsidies boosted Chesapeake Energy Corporation's expected project returns by around $9 billion in total, primarily from oil and gas fields under development in the Marcellus Shale of the Appalachian Region and in the

Figure 4. Estimated increase in expected net present value (in billions of nominal USD) – due to the three subsidies analyzed in this study – of new oil and gas fields first developed in each decision year between 1998-2019, by company (or companies) that conducted the original development in that year. (For fields with multiple historical companies, benefits are assigned based on their relative investments. See Appendix for details). Individual results are plotted for 16 specific companies with the largest estimated increases, in order of decreasing value across all years from bottom to top (i.e., Chesapeake is the largest between 1998-2019). As described in the caption to Figure 2, the values in early years (e.g. pre-2005) are likely artificially low because of pessimism in our model.

Estimated increase in expected value by historical company (billions of USD)
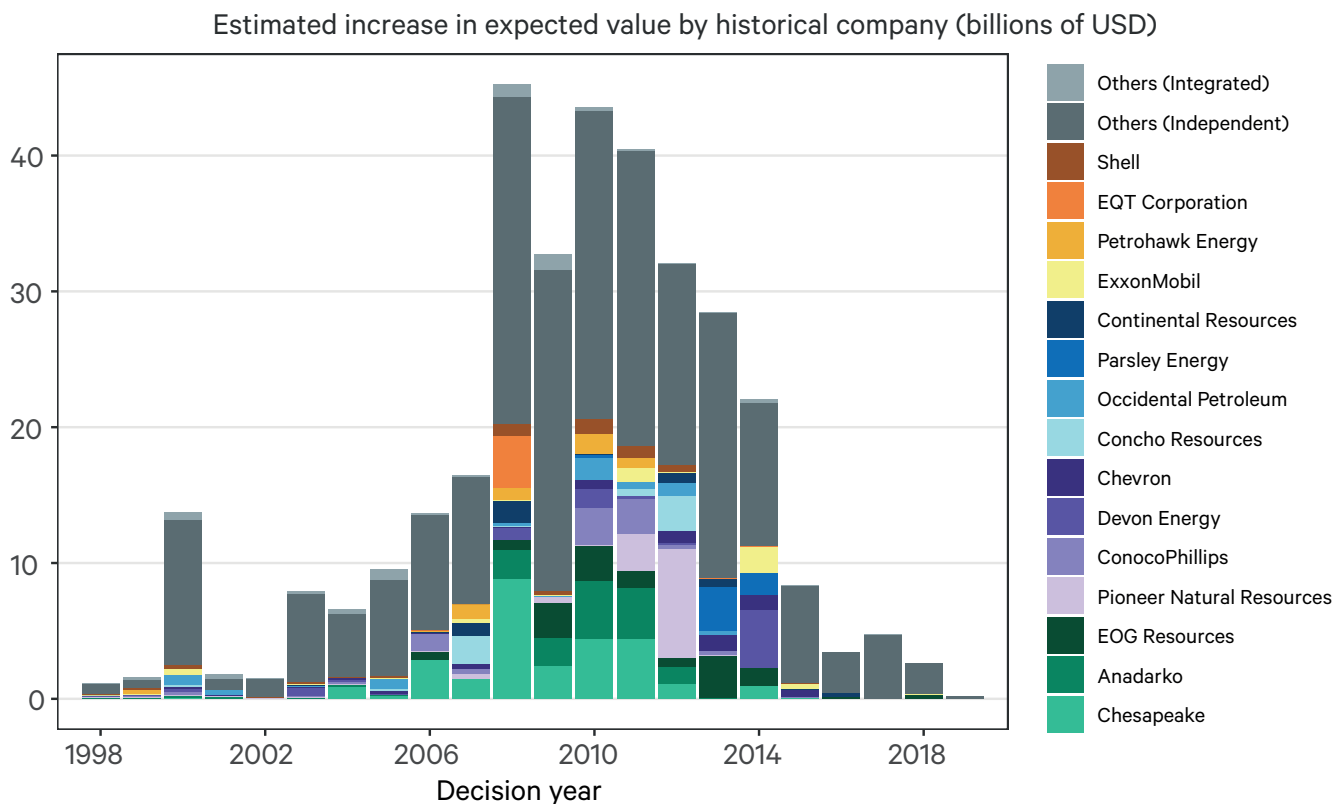
Haynesville region. This observation seems to match Chesapeake's own reports at the time. As detailed in their 2008 annual report, Chesapeake announced its discovery of the Haynesville Shale in March of that year. Furthermore, after having entered the Marcellus Shale in 2005 through its acquisition of Columbia Natural Resources, Chesapeake anticipated "ending 2009 as the most active driller and the largest producer of natural gas from the Marcellus" (Chesapeake Energy Corporation, 2008). In 2010, "a very important year of transition", the company expanded their focus beyond gas to include oil and natural gas liquids production from many other major shale plays, including those in the Permian (Wolfcamp and Bone Spring), the Eagle Ford, and the Niobrara (Powder River Basin) (Chesapeake Energy Corporation, 2010). We estimate that the three subsidies could have increased Chesapeake's expected returns from these developments in 2010 by $4 billion.

Similarly, in 2012, Pioneer Natural Resources' annual report discussed how the company was "successful in appraising and initiating horizontal development of the southern 200,000 acres of the Wolfcamp play". It went on to describe its success: "The wells Pioneer drilled in the Wolfcamp Shale and Jo Mill intervals utilizing horizontal drilling and hydraulic fracturing technology exceeded expectations and have revolutionized our approach to maximizing the recovery of oil and liquids" (Pioneer Natural Resources, 2012, p. 1).

In that decision year, we estimate that the three subsidies could have amplified Pioneer's expected project returns – mainly from fields being developed in the Permian Wolfcamp shale play – by $8 billion in total. Indeed, the company's annual report discussed how elimination of these three federal subsidies "could… defer planned capital expenditures if such changes accelerated the payment of taxes" (Pioneer Natural Resources, 2012, p. 25).

Subsidies likely affected decision-making at times of low prices

A persistent debate over subsidies is the extent to which they affect the decision to develop and drill new fields, versus how much of their value goes entirely to extra profits, over and above what would have been necessary to secure the green light for project investment.

Previous analyses have looked at the effect of subsidies on field decision-making based on whether subsidies push projects from below to above a pre-defined profit threshold, as measured either on an internal rate of return (IRR) or net present value (NPV) basis (Erickson et al., 2017, 2020; Metcalf, 2018). These prior studies also show how the resulting estimates of subsidy dependence can be very sensitive to the prevailing oil and gas prices at the time.

This analysis confirms that general finding. For example, when oil prices were high (above $60/barrel) between 2007 and 2014, our analysis estimates that less than 10% of oil resources by volume were pushed over decision thresholds by subsidies in each year (assuming a 10% IRR hurdle rate). In these years – when the increases in expected value appeared to be the highest (as shown in figures above) – we estimate that subsidies had relatively little effect on the decision to drill. This finding aligns with analyses done during the time (Aldy, 2013; Krueger, 2009), which showed that the subsidies were providing a large value to companies but causing relatively little new investment on the ground. However, the large added value may still have encouraged new capital to flood the market. Analysts reported at the time that the industry was "awash in capital", with new investors entering the market in search of these inflated profits (NGI Staff Reports, 2006). This ultimately helped contribute to too many wells bring drilled, an over-supply of oil, and a market crash (Sanzillo et al., 2018)

When oil and gas prices fell markedly in 2015-2016, project financial metrics no longer looked nearly as good, and individual projects may therefore have been more sensitive to the value provided by the subsidies. For example, as previous analyses have also shown – and as we also find here – the increases in expected returns in 2016 were enough to push more than 30% of new oil projects into profitability, greenlighting their investment decisions.

The situation was likely somewhat different for gas, which, unlike oil, did not experience rapidly rising prices in 2010 and the few years thereafter. For example, in years 2010-2012, gas prices were low and many projects were marginal; in those years, subsidies likely played a substantial role in making new gas projects in Appalachia viable (our model suggests over 30% of new projects may have been subsidy-dependent in 2010, for example). Therefore, these subsidies could have spurred on the shale gas boom that began in 2010 in that region (Erickson & Achakulwisut, 2021).

Since 2017, two factors have somewhat altered the dependence of new oil and gas fields on subsidies. One is the overall reduction in the corporate tax rate, passed by Congress in 2017, from a 35% marginal income tax rate to a flat income tax rate of 21%. With lower taxes meaning lower costs, subsidies have a somewhat smaller effect on the decision to drill, for the simple reason that more projects are profitable regardless of subsidies. In addition, with firms also having found other ways to reduce costs (e.g. cost reductions for fracking sand and other raw materials), overall profits may now be higher, further reducing firms' reliance on subsidies for greenlighting projects, even under low oil and gas prices. Accordingly, the subsidy dependence of projects going forward may not be as high as it was prior to 2017.

Nevertheless, we emphasize that these findings are estimates, given that our model cannot definitely determine how subsidies may have changed decision-making and affected the development of a new project in the past. This is partly because a project that was made economically viable by subsidies in a given year may well have gone forward without the needed boost from subsidies in another year when prices increased, and vice versa.[2]

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2   We discuss this and other limitations of our model for assessing subsidy dependence in more depth in the Appendix.

Discussion and conclusions

This analysis looked at the last two decades of investment data for US oil and gas fields to evaluate how major federal subsidies may have played a role in the huge boom in US oil and gas production. We found that federal subsidies amplified the expected financial returns of investing in unconventional oil and gas development, thereby helping to spur and sustain the US shale boom over the last two decades.

In particular, our analysis estimates that two tax incentives alone – the expensing of intangible drilling costs and percentage depletion provisions – increased the expected value[3] of new oil and gas projects by billions of dollars in most years, and by over $20 billion in some high-price years. This translates to a median increase in expected value of $4 per barrel of oil equivalent or more for projects in those high-price years (i.e., 2008 and 2010-2014. See Figure S1).

More specifically, we find that subsidies added substantial value to new oil and gas projects considered during the shale booms in the Bakken formation in 2005-2006, the Appalachian and Haynesville regions in 2008, the Eagle Ford play in 2009-2010, and the Permian basin in 2011-2015. This is when subsidies provided the most overall value, but it is likely that subsidies made the most difference to prospective new projects at other times, including when prices were low, and new projects therefore more marginal. Many oil projects in 2016 were marginal (and subsidy-dependent), as were many gas projects in Appalachia in 2010-2012.

The issue of fossil fuel subsidies is high on President Biden's agenda, as well as those of several members of Congress, who are looking to reform the US tax code alongside a broader effort to repair infrastructure and revitalize US manufacturing. Our findings show how such tax provisions have boosted oil and gas firms' expectations of profits over the last two decades. In the push to create a modern, low-carbon economy, the tax code is a powerful policy tool, and can be used to help transition away from high-carbon industries, like fossil fuels, to less polluting forms of energy.

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3   Estimated net present value at the time of the investment decision.

Appendix

Supplemental figures

Figure S1. Change in net present value by subsidy on a levelized basis, i.e. in units of USD per barrel of oil equivalent (boe), calculated as the median across all new oil and gas projects first developed in each decision year. Other details in caption of Figure 2 also apply.
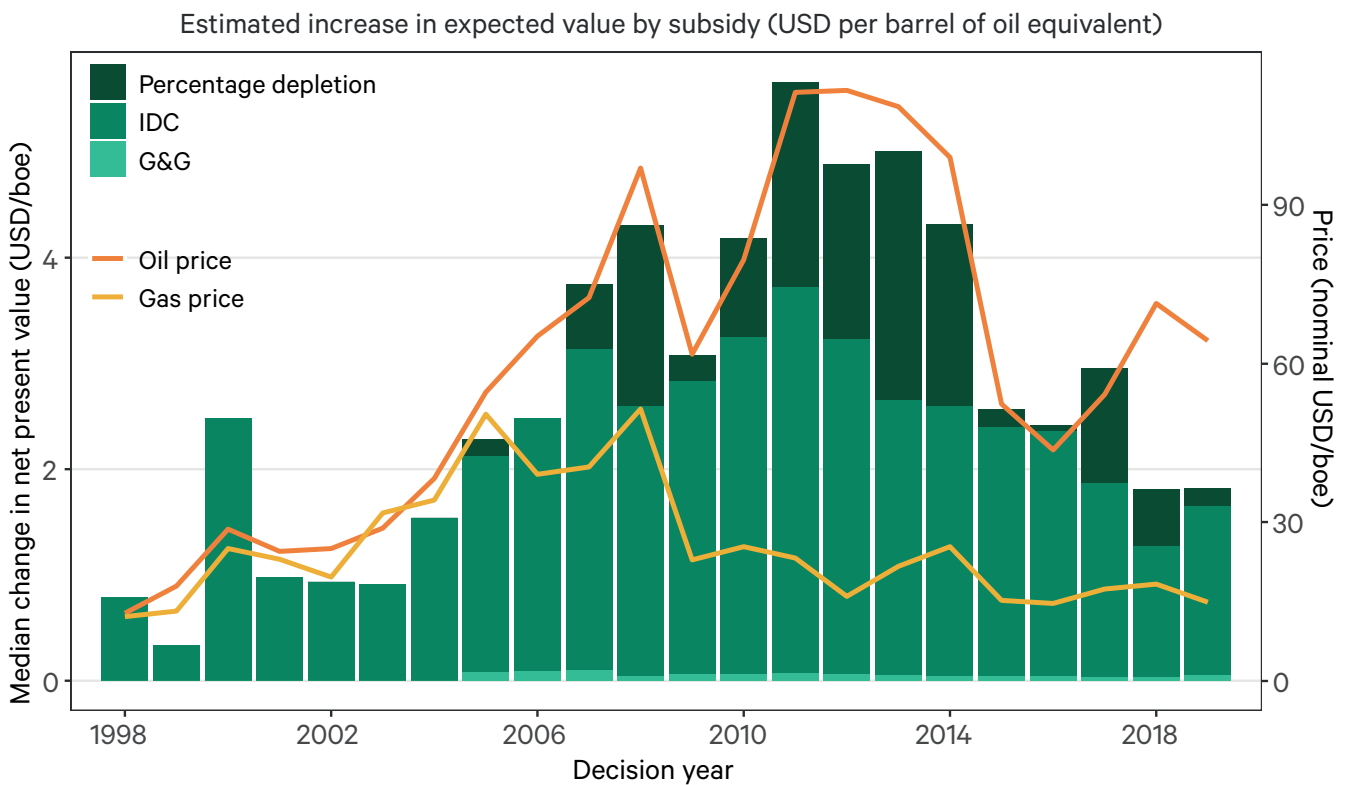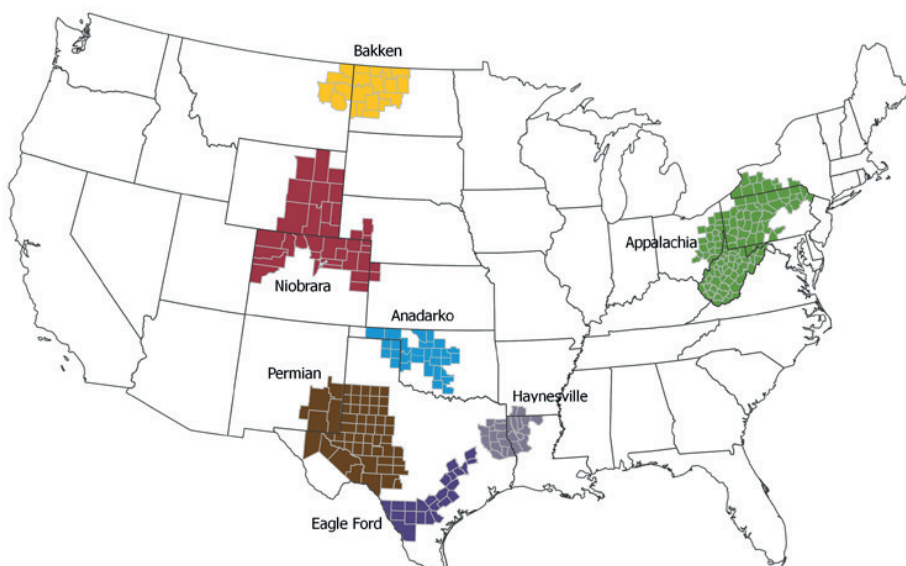

Figure S2. US map of major unconventional oil- and gas-producing regions. Source: US EIA (https://www. eia.gov/petroleum/drilling/)

Source: US Energy Information Administration

Detailed methods

This study relies on the methods and model we have previously used to analyze how the IDC, percentage depletion, and geological and geophysical subsidies affect the expected investment returns of new, not-yet-developed oil and gas fields in the US (Achakulwisut et al., 2021; Erickson et al., 2017, 2020). Here, the model is applied to fields that have already been developed, but still from a forward-looking standpoint. Broadly, the method is to develop a cash flow model for each oil or gas field that was developed in the United States over the last couple of decades, using actual capital investment, operating cost, and production data obtained in February 2021 from Rystad Energy's UCube database (Rystad Energy, 2021).

For each individual oil or gas field, we develop both a *without-subsidy* case and a *with-subsidy* case of how prospective project cash flows would evolve (which is, here, mainly a difference in tax treatment), and calculate standard financial metrics (e.g., net present value) used for decision-making. We assume a discount rate of 10% (on a nominal basis), which is consistent with our prior studies, the assumption of the data provider, Rystad Energy, and recent empirical research on actual hurdle rates for US oil and gas projects (Fattouh et al., 2019). The baseline *with-subsidies* case was modeled using the historical stream of capital costs, operating costs, and production data provided by Rystad Energy. The *without-subsidies* cases are then constructed by sequentially modifying the baseline conditions to reflect the combined effects of the removal of each subsidy, one after another, in the following order: (1) the percentage depletion provision; (2) the expensing of intangible drilling costs; and (3) the accelerated amortization of geological and geophysical expenses. The modeled effect of each subsidy is largely insensitive to the order in which they are removed, given that each affects a different portion of capital investment.

The value of the subsidies is estimated as the difference in net present value (NPV) between the *with-subsidy* and *without-subsidy* cases over forty years (starting from our estimated decision year). In all cases, the expected oil and gas prices for each investment decision are the then-current prices at the time, since, as Hamilton (2009) has shown, the best estimate of future oil and gas prices is the current price (Hamilton, 2009). Our analysis of subsidy value is therefore composed of estimates of the expected value as field operators would have seen it *at the time they made their decisions to invest in new fields*. Our estimates are not, therefore, intended to represent the actual profits made (or lost) as those investment decisions played out in subsequent years. As a sensitivity test, we also ran our model assuming that firms did have perfect foresight on how actual prices would evolve (i.e., exactly anticipating the large price swings shown in Figure 1a), as implausible as that is. The results shown in Figure 2 would be lower or higher by 3%-37% depending on the year (with larger differences seen in higher-price years), largely due to changes in the effect of the percentage depletion subsidy, which is dependent on revenue and taxable income.

For further details on how the *with-subsidy* and *without-subsidy* cases are constructed for each subsidy – as well as on the exact types of costs extracted from the Rystad database – readers are referred to the prior studies for details of the model and methodology. The main difference in this study is that, as mentioned in the first paragraph of this Appendix, instead of applying the method to new, not-yet-developed fields, here we apply it to already-existing fields or, more precisely, to oil and gas fields that underwent an investment decision between 1998-2019 and which were then developed, producing oil and gas.

Because of this difference, several aspects of the model and the methodology were adjusted compared to prior studies. Chiefly, since the US tax code – including fossil fuel subsidies – has changed somewhat over the analysis period (fields with decision years between 1998 and 2020), we needed to identify a specific tax regime for each individual year, depending on the circumstances at the time.

One such factor is the statutory top corporate tax rate: 35% from 1993 to 2017, reduced to 21% from 2018 onwards (Tax Policy Center, 2015). For investment decisions made up to 2017, then,

we assume that the marginal tax rate that applies is 35%. We do not assume that firms making decisions in 2017 or earlier had perfect foresight that could anticipate the cut in tax rate in 2017. For example, a firm that decided to invest in a field in 2014, which began producing in 2015, is assumed to have foreseen the tax rate to be 35% for its entire production, even production that occurs in 2018 and the years thereafter, since the firm did not have a crystal ball. Then, beginning for decisions made in 2018, we assume a marginal tax rate of 21%, since by 2018 the tax cuts had passed Congress.

As for the subsidies themselves, the key features of the IDC and percentage depletion subsidies analyzed here have all been unchanged over the course of the period analyzed.

More specifically, for the intangible drilling cost subsidy, the limit for integrated operators – that they can immediately deduct no more than 70% of their intangible costs – has been in place since the Tax Reform Act of 1986 (US GAO, 2000). That 1986 law also increased the recovery period for the other 30% from 3 years (put in place in 1982) to the current 5 years (Joint Committee on Taxation, 2009).

For the excess of percentage over cost depletion, the currently allowed rate of 15% has been in place since 1984. Before that, it was at 27.5%, before being reduced to 22% in the Tax Reform Act of 1969 (Fiekowsky, 1974; Joint Committee on Taxation, 2009). Integrated producers have not been able to claim this subsidy since the Tax Reduction Act of 1975 (US GAO, 2000). The limit on how many barrels of oil (or gas equivalent) are subject to the deduction has been 1,000 barrels per day since 1980 (before that, it was 2,000 barrels per day) (Fiekowsky, 1974).

By contrast, the accelerated amortization of geological and geophysical expenses subsidy has changed substantially over the course of our analysis period. This subsidy was first adopted in the Energy Policy Act of 2005. Prior to that time, costs associated with dry holes (subsequently abandoned) could be deducted immediately (expensed), whereas costs associated with producing wells (the subject of this study) would be added to the cost basis and recovered over the life of the well (Joint Committee on Taxation, 2009). The amortization period was extended to five years for integrated operators in 2006, and again to seven years in 2007 (see table) (Joint Committee on Taxation, 2009), as shown in Table 1. All of these changes are included in our analysis.

Table 1. Treatment of geological and geophysical expenses for independent and integrated operators over time

Year	Independent operators	Integrated operators
Pre-2005	Costs for productive wells recovered over life of well (cost for dry wells can be expensed)	
2005	Two-year amortization introduced	
2006	[No change]	Amortization period extended to five years for costs paid or incurred after May 17, 2006 (IRS, 2015)
2007 and later	[No change]	Amortization period extended to seven years for costs paid or incurred after December 19, 2007 (IRS, 2015)

Since the availability of subsidies depends on whether firms are considered independent or integrated, we also needed to determine what types of firms were making the decisions and directly benefiting from the tax consequences in each year. In cases when a field was solely owned by a single firm in the decision year, this determination was straightforward, since Rystad's database includes classifications of each company that enable clear delineation of independent and integrated firms (see the Supplemental Information of Achakulwisut et al., 2021). However, joint ownership of fields is common, and the US tax code provides substantial latitude for joint

ownerships to allocate the expenses to one firm versus another. Therefore, for joint owners, we assumed that firms would make such allocations in ways that would maximize their tax benefits, i.e., that they would use the independent status if joint ownership by independent firms was 50% or more. In all cases, we assumed that the ownership and status was foreseen by the original field developers to stay the same over the life of the field. Accordingly, our method does not anticipate or capture the effect of ownership changes that occur after field development began.

Lastly, our prior studies (Achakulwisut et al., 2021; Erickson et al., 2017) have included a greater focus on measures of subsidy dependence, or the fraction of economical oil or gas resources that are only viable because of subsidies (at given oil and gas prices). However, that approach is challenging to apply to historic fields, and so the limited results on subsidy dependence presented in this text are not directly comparable to values reported in our prior work. The challenge arises for two main reasons. First, the denominator of subsidy dependence – economic oil or gas resource – requires a clear understanding of all such prospective investment opportunities that are economic (e.g. NPV at least zero) at a given set of oil and gas prices. For our prior studies, that denominator was straightforward to calculate, because our underlying data source, Rystad Energy, provided data for all such fields for which oil or gas had been discovered and which therefore could, in principle, be developed. However, for any given historical year, we have no way of knowing the full extent of fields that had been discovered, and were therefore candidates for potential development, at that time. Instead, we have only a record of what fields actually began development in any given year – not what other fields might have been developed if conditions allowed. Accordingly, any estimates of subsidy dependence we would make, based on these historical data, would likely have a denominator that is artificially low, and therefore, an estimate of subsidy dependence that is likely too high.

The second reason that we were not able to evaluate subsidy dependence to the same extent as in prior studies is that, in some cases, our model estimates fields to be unprofitable (i.e. NPV<0), even though we know that they were actually developed (and therefore included in the Rystad database). This discrepancy between our model's assessment of field viability and what actually happened is greater in earlier years (i.e. 2004 and before) than in later years. This may partly be a function of reduced data quality in early years, since Rystad Energy was only founded in 2004 and so had to reconstruct prior investment patterns to populate its database. For this reason, we focus the few assessments of subsidy dependence in our text on years where our model performs well relative to what actually happened. (When we ran our model instead assuming that firms did have perfect foresight on how actual prices would evolve, this did not substantially improve the models' performance in estimating the investor decision to invest.)

Note that these limitations in assessing subsidy dependence do not apply as much to our assessment of the increase in NPV due to subsidies. Our confidence in these results is higher because they do not require making a binary assessment for each field or having any knowledge of the full set of all potential fields under consideration for development. Still, our model's pessimism about the modeled NPV for fields in 2004 and before has, as a consequence, resulted in very low or zero estimates for the value of the percentage depletion allowance for most fields that were initiated in those years (see Figure 2). This is because this subsidy derives from taxable income at the level of an individual property, which our model estimates to be very low or negative for most new fields under the prevailing oil and gas prices at the time. We suspect that our estimates here are too low but, since we are not able to validate the underlying data used for those years, we nonetheless do report the values, noting these caveats.

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