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Innovation Begets Innovation and Concentration: The Case of Upstream Oil & Gas in the North Sea*

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Abstract

We investigate the effect of technology adoption on competition by leveraging a unique dataset on production, costs, and asset characteristics for North Sea upstream oil & gas companies. Relying on heterogeneity in the geological suitability of fields and a landmark decision of the Norwegian Supreme Court that increased the returns of capital investment in Norway relative to the UK, we show that technology adoption increases market concentration. Firms with prior technology-specific know-how specialize more in fields suitable for the same technology but also invest more in high-risk-high-return fields (e.g., ultra-deep recovery), diversifying their technology portfolio and ultimately gaining larger shares of the North Sea market. Our analyses illustrate how technology adoption can lead to market concentration both directly through specialization and indirectly via experimentation.

JEL classifications: O33, Q40, D40
Keywords: innovation, adoption, market structure, competition, specialization, experimentation, upstream oil and gas markets, North Sea

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1 Introduction

Innovative technologies and their adoptions are a driving force for economic growth as they improve the allocation of resources (e.g., Aghion and Howitt, 2008, Cohen, 2010). Investigating the factors facilitating innovation is at the center of several research efforts. Among these factors, market competition received much attention, with both theoretical (Aghion et al., 2005) and empirical analyses (e.g., Bloom et al., 2012, Bergeaud et al., 2022) illustrating the benefit of competition in fostering innovation. However, the literature also suggests that innovation is often put forth by large rather than small firms (e.g., Pavitt et al., 1987, Pagano and Schivardi, 2003). These two observations raise questions about how innovation, in turn, may affect competition: since innovation makes large firms more productive (e.g., Collard-Wexler and De Loecker, 2015), does it enable these firms to exercise even more market power?

As is well known, identifying the impact of innovation on market concentration presents several challenges, as innovative firms may differ from others in terms of unobservable characteristics that may also affect their competitiveness. In this paper, we address these challenges by investigating the adoption of a specific technology, Enhanced Oil Recovery (EOR), in the upstream oil & gas industry in the North Sea during 1970-2000 on the basis of a triple-difference framework. We leverage heterogeneity in the geological and technological constraints for technology adoption across fields and an unexpected ruling of the Norwegian Supreme Court to evaluate: (1) the effect of EOR adoption on production, costs, and market structure; (2) whether EOR adoption is affected by know-how or other informational spillovers across oil & gas fields and firms; and (3) if these information channels in turn affect market structure by facilitating further EOR adoption or the adoption of other technologies for those who already adopted EOR in the past.

Enhanced Oil Recovery (EOR) facilitates the extraction of natural resources from a reservoir via the injection of natural gases (e.g., CO_2), chemicals (e.g., polymers), or heat. EOR has played a revolutionary role in developing the upstream oil & gas sector since its first successful CO_2-based project in 1972 in Scurry County, Texas (U.S. Department of Energy, 2010). Oil & gas extraction relies on the high pressure inside the reservoir to force resources up through the well. However, the reservoir pressure decreases over time, making the recovery of more than 20-40% of a reservoir's resources uneconomical without EOR (e.g., Sandrea and Sandrea, 2007, IEA, 2008b). By restoring pressure through the injection of suitable substances, EOR allows the recovery of up to 50-70% of the reservoir's crude oil (e.g., McGuire et al., 2000, Toole and Grist, 2003, Muggeridge et al., 2014). EOR can increase a field's life by a few decades and benefits firms and countries by extending their cash flows and royalties. In the period of our study, EOR was freely available to all oil & gas firms through service companies like Halliburton. No oil & gas company developed its own EOR projects. Instead, they hired specialized firms to acquire EOR infrastructures and training. Thus, in our context, firms face the simpler choice of whether to *adopt* EOR rather than to *develop* it anew. This facilitates our analysis as both the adoption decision and the EOR technology itself are relatively homogeneous among firms in the North Sea.

We conduct our analyses on the basis of a unique dataset from Wood MacKenzie, a data consulting firm, which records detailed information about each field's marine geology and yearly production, reserves, and operative and capital expenditures. We observe yearly activities by all firms in all fields in the Southern basin of the North Sea between 1970 and 2000. This basin is a mature area and is one of the areas that saw most underwater EOR activities globally (Alvarado and Manrique, 2010), which contributed to the development of important energy hubs like Aberdeen in the UK (Cumbers, 2000).[1] Two unique features of the data are particularly helpful for our analysis. First, Wood MacKenzie collects extraordinarily detailed information on fields' geology, location, and employed technology. Second, within each field, we observe exhaustive information about each operating firm. The data do not only record production, but also all sources of cost incurred to generate it.

Our triple-difference identification strategy relies on our detailed micro-data by combining two sources of variation for EOR adoption. First, not all oil & gas fields are geologically and technologically eligible for EOR adoption. Our detailed field-level data allow us to determine whether each field is eligible for adoption on the basis of geological features such as API gravity, reservoir depth, and the availability of suitable technological infrastructures such as fixed platforms or drilling developments located on the seafloor (Al Adasani and Bai, 2011, Nwidee et al., 2016). The lack of eligibility of a field represents a constraint for EOR adoption, irrespective of unobserved firms' characteristics and willingness. However, the eligibility of a field for EOR would not be on its own sufficient to address our endogeneity concerns, in that more productive firms could still self-select into EOR eligible fields on the basis of their willingness to adopt EOR at a later stage.

We then combine the status of EOR eligibility of a field with an unexpected shock that changed the returns from EOR adoption for fields located in Norway but not in the UK. We take advantage of a 1985 ruling of the Norwegian Supreme Court which decreased the legal risks from capital investment in Norwegian relative to British fields. We compare outcomes for fields and firms operating in Norway before and after 1985, using similar

[1] For instance, Holt et al. (2009) document the importance of carbon dioxide (CO_2) pipes from Aberdeen to the Ekofisk Area, one of the largest oil and gas reservoirs, allowing the delivery of CO_2 to the fields in this area.

UK fields and firms as controls. We first show that the Supreme Court decision led to substantially larger EOR adoption in Norway compared to the UK. Then, we document increasing trends in concentration for Norwegian relative to British fields that were eligible for EOR prior 1985. On the one hand, innovation increased specialization as the ownership of EOR eligible fields became more concentrated around firms more exposed to EOR before the ruling. On the other hand, it increased experimentation as these firms reinvested the greater cash flows from their EOR fields into seizing more complex and riskier projects like ultra-deep recovery, where other new technologies are also needed. Both channels increased concentration, with the HHI in Norway growing twice as large as in the UK since 1985. The underlying mechanisms view specific know-how, in this case, past exposure to EOR as a field operator, as a novel source of concentration.

Our analysis focuses on two margins of market power: "intensive margin," the ability of firms to raise production by adopting EOR in their current fields, and "extensive margin," their ability to enter or exit fields that are eligible for EOR. Firms more exposed to EOR at baseline are more likely to enter EOR-eligible fields after the Supreme Court decision, suggesting a vital role for the extensive margin to explain changes in market shares. As a result, innovation adoption increases concentration not only due to the efficiency gains accruing to adopting firms, but also because it pushes them to produce more given a (almost) horizontal residual demand curve — i.e., the North Sea accounts for only 4% of global production (BP, 2021) and these firms are unlikely to have market power vis-à-vis their OPEC counterparts.

Nevertheless, having successfully experienced EOR adoption appears to be sufficient to generate valuable specialized know-how. To substantiate this statement empirically, we rely on the fact that while multiple firms generally own each field, only one firm is in charge of its operation (i.e., decides about operative and capital investments). We find that fields operated by firms that already adopted EOR in other fields are 74% more likely to adopt EOR in Norway than in the UK. Instead, past adoption of EOR by shareholders other than the operating firms and proximity to other EOR projects have no material implications for future EOR adoption.

Consistent with this, we show that know-how increases firms' market shares: being exposed to one additional EOR eligible field as an operator prior the Supreme Court ruling increases the firm's market share in the post-period by 7%. The extensive margin drives market shares as firms with direct know-how on EOR at baseline enter more fields than firms without such know-how. Although the former firms enter EOR eligible fields more than the latter firms due to specialization, they also enter non-EOR eligible fields more often, signaling that successful exposure to one technology could also affect a firm's taste for other assets where different technologies might be more appealing.[2] In particular, we find that these firms invest in riskier and costlier projects like deeper fields or fields with sour and heavy oil, which require the support of other new technologies. This finding suggests a shift in the risk attitudes of oil and gas firms due to successful direct expertise on certain technologies. In contrast, informational spillovers by partnering with companies with EOR expertise do not lead to either specialization or experimentation, and do not impact a firm's market shares.

Our results reveal a novel mechanism for technology adoption to affect market structure and can inform the design of more effective innovation and antitrust policies. Strikingly, our findings come from a market for an homogeneous good without a downward-sloping demand, a context which should inhibit rather than foster concentration. Therefore, we expect the knowledge-based mechanism that we identify to be present also in other markets, in particular where market power can provide further benefits to innovative firms through the unilateral ability to increase prices. In these industries, our findings call for increased attention by regulators on the dynamics of innovation adoption and the resulting positions of market power.

Methodologically, our empirical approach follows Iaria et al. (2018), which uses multiple levels of analysis to elicit the impact of international cooperation on scientific output exploiting the onset of World War I. In a similar vein, we examine how outcomes across treated and control units have changed around a landmark decision by the Norwegian Supreme Court at different levels of aggregation. This decision limited the power of the Norwegian Government to unilaterally amend oil and gas licenses retroactively (Mestad, 1987, Hunter et al., 2020), which reduced the uncertainty of the returns of capital investments. The UK Government was never bound by similar limitations, as its constitution allows for retroactive changes to contracts in specific domains. Three unilateral changes to existing licenses indeed took place between 1975 and 1987, none of which saw a lawsuit by oil companies (Gordon, 2011).

To link the Supreme Court decision to EOR adoption, the first part of the paper employs this framework to show that fields and firms faced a similar tradeoff: Norwegian EOR eligible fields and firms that relied more on these fields at baseline saw greater production, operative, and capital expenditures after 1985 than similar British EOR eligible fields and firms, respectively. We also show that, while the ratio between production and operative expenditures increased for the former fields and firms, indicating a drop in average production costs for treated fields and firms, the ratio of production over capital

[2] Bower and Young (1995) discuss the importance of new technologies for players in the North Sea where untapped energy resources are often located in deep and costly areas.

expenditures stayed constant. These findings highlight a tradeoff between the fixed cost expenditures to adopt new technology — which in the EOR case mainly consists of a tank to hold chemical substances (e.g., carbon dioxide, steam, or chemical polymers) to be injected into the reservoir to increase its pressure — and current expenditures — the purchase of such substances make up the increase in operative costs. Similar trade-offs are typical of capital investments in new technologies. With the finding mentioned above of an increase in EOR adoption in Norway compared to the UK after the Supreme Court decision, these changes in production and costs support our usage of this decision to identify how technology adoption impacts market structure.

Our main contribution is to illustrate a feedback loop from innovation to competition. Many studies focus on the opposite link from competition to innovation (e.g., Schumpeter, 1943, Arrow, 1962, Nickell, 1996, Aghion et al., 2005, Bloom et al., 2016, Bergeaud et al., 2022). Generally, the objective of policymakers is to create a market structure that boosts innovation and adoption of innovative technologies. However, while a few studies illustrate the existence of correlation between innovation on market structure (e.g., Olmstead-Rumsey, 2020, Horn et al., 2021), the causal effects of innovation on competition are not well understood. On the one hand, innovative industries drive the growth of advanced economies (e.g., Oliner and Sichel, 2000, Jorgenson et al., 2005, Bloom et al., 2012, Syverson, 2011, Graetz and Michaels, 2018). On the other, we observe substantial increases in market concentration in advanced economies that reduce aggregate welfare (e.g., De Loecker and Eeckhout, 2018, Autor et al., 2020, Bessen, 2020, De Loecker et al., 2020). If innovation adoption itself has anti-competitive effects, antitrust policy may play a crucial role in preventing agglomeration and welfare reductions in industries where innovation is important.

A large literature studies the innovation process and its interplay with market competition. These papers often focus on specific industries for identification reasons. For instance, within the hard disk industry, Igami (2017) shows that incumbent firms have low incentives to adopt innovations because of the risk of cannibalizing their own product offerings, while Igami and Uetake (2020) show how merger policy dynamically incentivizes or deters mergers and innovations. Other contributions include Hashmi and Biesebroeck (2016) in the car industry and Macher et al. (2021) in the cement industry. In all these studies, innovation increases productivity, as documented in other strands of the literature (Griliches, 1979, Bloom et al., 2013, Doraszelski and Jaumandreu, 2013, Bilir and Morales, 2020), but adoption also responds to competition through the slope of the residual demand.

Our setting differs from these studies in several ways. First, we focus on a homogeneous good, oil, in a market where firms have a horizontal residual demand curve, which prevents cannibalization issues and competition on quality. Second, we control for endogenous adoption by employing a policy change as a cost shifter for exposed firms and by taking advantage of detailed geological data about Norwegian and British fields that are eligible for the technology. Third, the technology is not internally produced by any of these firms but acquired from service companies, similar to how firms purchase or rent other drilling equipment. This setting allows us to identify a new factor related to innovation that can potentially reduce consumer welfare beyond the well-studied cannibalization effect (Igami, 2017): a firm's past know-how about a specific technology induces more investments in assets amenable to the same technology. In our settings, these firms' market shares increases as a result and, in markets with downward sloping demands, might create market power and negatively affect consumer welfare.

We also contribute to an extensive literature studying several aspects of the oil industry. Seminal papers in this field include Porter (1995), who studied bidding for exploratory licenses. Related works extended the empirical framework to potential correlations across agents' valuations (Hendricks et al., 2003, Compiani et al., 2020, Kong et al., 2022), to sequential bidding (Kong, 2021) and auction design (Bhattacharya et al., 2022, Covert and Sweeney, 2019). More recently, a literature developed investigating the mismatches between adopted technologies and oil field characteristics (Vreugdenhil, 2020) and how production cost differences across fields can be exploited to estimate the welfare losses due to misallocations (Asker et al., 2019) and to the OPEC cartel (Asker et al., 2021).

Unlike other empirical investigations of the oil & gas industry, our paper focuses on a specific technology, Enhanced Oil Recovery which, in one of its most standard usages, employs large quantities of carbon dioxide (CO_2). Looking forward, coupling EOR projects with CO_2 capture technology is viewed as a potentially effective way to decarbonize the energy sector, while still positively impacting the budget of oil-exporting nations (Shogenova et al., 2021); capturing CO_2 onshore and transporting it offshore to be stored in EOR projects and transferred into underground reservoirs as they get depleted can simultaneously help global decarbonization efforts and reduce energy production costs if carbon capture storage is adequately incentivized (e.g., Mendelevitch, 2014, Oei and Mendelevitch, 2016, Santos et al., 2021). CO_2-EOR projects are being considered by governments worldwide (e.g., IEA, 2008a, 2022a), and several pilot projects have been advanced in India (Shackley and Verma, 2008) and China (Hill et al., 2020), with preliminary positive results (Núñez-López and Moskal, 2019). A number of recent studies indicate that this technology can also be adequately deployed in the North Sea if fields can share CO_2 pipelines (e.g., Holt et al., 2009, Kemp and Kasim, 2013).[3]

[3]For instance, in 2021 Norway started an "absolutely necessary" CO_2-EOR project capable to bury up to

The rest of the paper is organized as follows. Section 2 describes the upstream oil and gas industry in the Northern Sea, the Enhanced Oil Recovery technology (Section 2.1), and the 1985 Norwegian Supreme Court Decision (Section 2.2). Section 3 presents our data. Section 4 shows the empirical evidence indicating that the Norwegian Supreme Court decisions differentially affected EOR adoption in the UK and Norway and presents the identification and estimation approach that will be carried out in the remainder of the paper. Section 5 studies the effects of EOR on production and costs, while Section 6 studies the implications of EOR for market concentration. Section 7 zooms in on know-how as a mechanism for industry concentration. Section 8 discusses our results and Section 9 concludes.

2 Upstream Oil and Gas in the Northern Sea

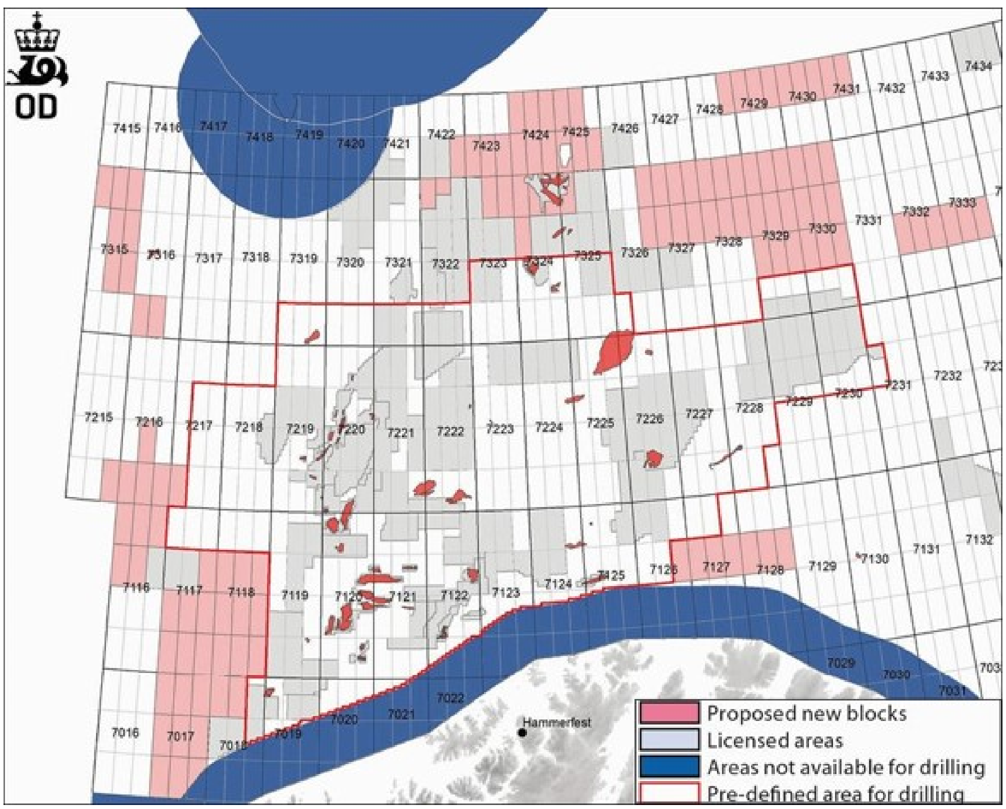
In the North Sea, natural gas was first discovered in commercial quantities in the Groningen region of the Netherlands in 1959, and similar geological characteristics led geologists to suspect that similar opportunities might also be available in the offshore sector of the UK (Odell, 1996; Yergin, 2011). Early attempts at searching for oil & gas in the UK sector of the North Sea were mostly met with limited success in the early 1960s, but larger finds in the latter half of the decade then led to significant investments in the region's offshore energy industry. The discovery of the giant Ekofisk oil field in Norwegian waters in 1969, followed by the discovery of the Montrose and Forties oil fields in the UK sector in that same year, brought the regional energy markets into the spotlight (Shepherd, 2015). The discovery of the Kraka field in the Danish offshore sector in 1966 meant that also Denmark had a stake in the emerging North Sea oil & gas market, albeit a significantly smaller one than the UK or Norway. Production in the region continued to grow until 2000, but the region is now considered to be mature and unlikely to return to its peak production levels (Craig et al., 2018). Where the combined oil & gas production from the North Sea once provided approximately 8% of the global total, in 2020 the region produced about 4% (BP, 2021).

Allocation of licenses. The allocation of oil & gas exploration and production rights in Norway and the UK are comparable in many regards. In both countries, the state owns all sub-sea petroleum resources, and activities related to the oil & gas industry can only be carried out when the government for that territory has provided approval. In Norway,

1.25 billion tonnes of CO_2 under the North Sea (Fairs, 2021). Also in terms of legislations, several countries have been considering or implementing carbon offset programs for CO_2-EOR projects (e.g., McMahon, 2018, Hodgson, 2022).

these processes are managed through three types of licenses: an exploration license, a production license, and a license to install and operate facilities (Brøvig et al., 2018). These licenses are awarded in an annual bidding round in mature areas, and every second year in so-called "frontier" regions that have not yet been significantly developed. Figure 1 shows an example of a typical bid allocation map from Norway in 2020. In a process that closely mirrors Norway's, firms wishing to participate in the UK upstream oil & gas sector must also bid for a license to explore UK territorial waters, or acquire an interest in existing assets (Mace et al., 2017). The UK process is managed by the Oil & Gas Authority (OGA). Prior to the establishment of the OGA through the UK's Petroleum Act in 1998, however, licenses were distributed through competitive rounds by the Department of Energy and Climate Change (DECC).

Figure 1: Allocation blocks from Norway's 25th Oil & Gas licensing round



Notes: The figure refers to the recent 2021 round for oil and gas licensing applications in Norway. Most of the blocks in this round (125) are in the Arctic Barents Sea, and only 11 blocks are in the Norwegian Sea. According to the regulations, assessments of the petroleum potential of these areas was already available before the consultation period, which ended in August 2020. The deadline for applications and award announcement was in 2021. Similar maps are created at every bidding round both in Norway and in UK. Source: (GEO Expro, 2020)

Oil & gas fields. Offshore oil & gas fields vary greatly in size. As an example, the Clair oil field in the Scottish Territorial Waters is the largest oil field in the Northern Sea with recoverable reserves of 8 billion barrels of oil, producing 120,000 barrels of oil a day (BP, 2018). Large oil fields often cover multiple license blocks, and multiple oil companies act as operators of such fields. In practice, the companies formalize a joint operating agreement (JOA) that governs the relationship of the consortium in oil production. The exact agreements are often based on the core competencies of the partners. In the oil & gas sector, often different stages of oil exploitation are related to various key duties for the parties involved (Garcia et al., 2014). The life cycle of an oil & gas field generally is divided in five phases: the initial three phases (exploration, appraisal, and development) focus on exploring and building infrastructures to access the relevant natural resources, the production phase focuses on the extraction and exploitation of oil & gas, and the last phase on closing an extraction site (Darko, 2014). The licensing of all countries in the North Sea involves a royalty system. During the exploitation phase, operators pay a set percentage of oil & gas revenues to the country a field belongs to. Formally, royalties are divided into multiple different revenue taxes that varied over the last 70 years (see Ryggvik (2015) for Norway and UK Government (2019) for the UK).

Oil & gas companies. The oil and gas companies active in the North Sea include major international players. Commonly, firms share their ownership over several fields. Therefore, a field typically appears in the portfolio of several firms. All the "shareholders" of a field have rights on the cash flows from the extraction activities based on their equity stakes in the field. Similarly, they are also responsible for the expenditures created by the exploration and extraction activities. These costs include operative costs (e.g., expenses for the workforce and for the purchase of substances to be injected into the reservoir that, as we will see in Section 2.1, are a central element of the technology we study int this paper, EOR), and capital expenditures, such as the rental of platforms, rigs, and wells, or other specialized equipment. Although a field is owned by multiple firms, only one of these firms can act as a "field operator." The field operator conducts both the daily operations of the field and makes strategic decisions such as when to move from one phase to another or when to invest in technology.

With the final goal to establish the foundations of the domestic petroleum industry, the early 1970s saw the creation of state-owned oil and gas companies in both the UK and Norway. The immediate objectives of such endeavors were to encourage oil and gas exploration and production, build up competencies within the upstream oil and gas sector, and maintain adequate domestic energy supply levels. The UK Government created the

British National Oil Corporation (BNOC), a nationalized body, under the provisions of the Petroleum & Submarine Pipelines Act 1975, which then became a private entity with the name of Britoil in the 1980s. The company eventually was incorporated inside what we know today as BP. Similarly, the Storting, the Norwegian parliament, created the Den Norske Stats Oljeselskap A/S, as a limited company directly owned by the Norwegian Government in 1972. Like BP, the company became a fully integrated oil company by investing in refineries and oil stations from the mid-1980s onwards. Our analysis controls for the presence of these two large and politically connected players.

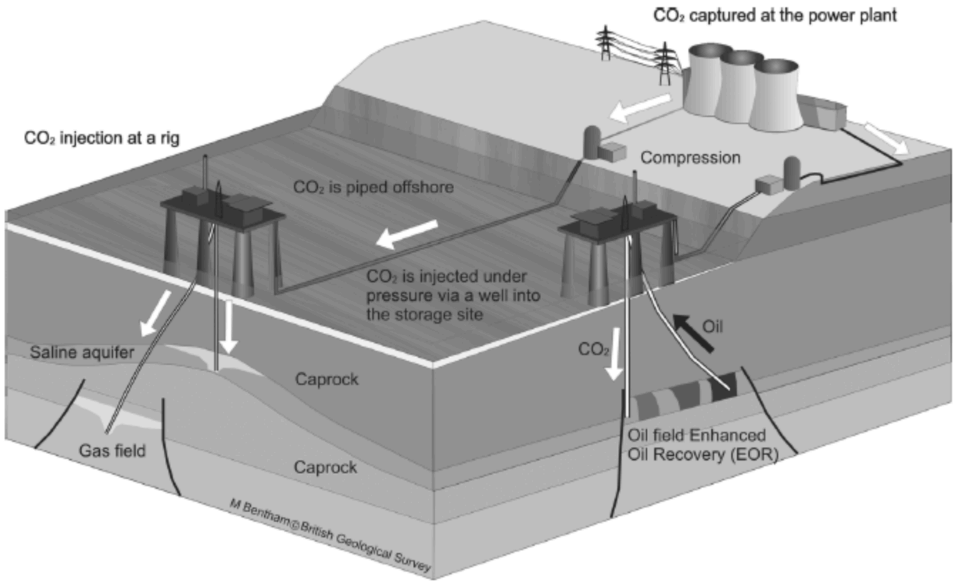
2.1 Enhanced Oil Recovery (EOR)

In the early days of a producing oil & gas field, the naturally occurring pressure within the reservoir provides the force required to move the flowing hydrocarbons towards the wells. This pressure gradually falls over time, however, which in turn reduces the rate at which the hydrocarbons can be extracted. The companies managing the reservoir then have a few technical options available to improve the flow rate. In the early stages of the pressure depletion, this can be as simple as injecting water or natural gas. While these will help to increase the pressure for a while, the reservoir pressure will however eventually resume its downward trend. Enhanced oil recovery (EOR) can then be considered.

Enhanced oil recovery (EOR) is a process that alters the chemical composition of the oil and gas in a reservoir in order to ease its extraction. As shown in Figure 2, this can be achieved through CO_2 injection, but also through chemical flooding, the injection of nanofluids, the injection of heat, or hybridized approaches involving combinations of these (Alvarado and Manrique, 2010, Tarybakhsh et al., 2019, Wei et al., 2021).

While EOR frequently can improve the production rate of a petroleum reservoir, it however tends to be expensive and difficult, and it is typically applied only after easier, less costly alternative approaches to improving pressure have been exhausted. Because of the large number of variables involved with implementing a customized EOR for a reservoir, there is no simple, one-size-fits-all pricing structure for the application of this technology. Because of the high customization, EOR tends to entail large up-front capital requirements and long pay-back periods. As a result, EOR adoption has historically relied on some form of public support and has represented a strategic choice for oil & gas companies. Today, over 80% of global EOR production benefits from some sort of government incentive or is prioritized by national oil companies as part of their efforts to maximize the return from national resources (IEA, 2022b). The costs for EOR have come down since 2014, but the costs of other projects—including shale and offshore developments—have decreased more,

Figure 2: An Enahnced Oil Recovery (EOR) operation



Notes: The figure illustrates the working of a standard EOR operation. First, the injected chemicals are produced onshore. In the depiction, the chemical is CO_2 and it is captured at a closeby power plant before being delivered to the platform through a pipeline. In the absence of a pipeline, chemicals can also be shipped offshore. The chemicals are then stored in a tank in the platform, which direct them at the right pressure and density in the reservoir through injections rigs, which are strategically placed by the outsourced engineering service company (e.g., Halliburton). The chemicals moves through the pore spaces of the rocks in the reservoir and misces with droplets of crude oil to form concentrated oil banks that are finally swept towards the production wells. Oil is then separated from water at the production well. The injected substances and the pattern of injection are modeled through computer simulations. This description applies to oil fields (most of the North Sea production is oil) and is depicted in the platform to the right of the figure. A similar approach applies to gas fields, which is depicted to the left of the figure. Sources: House of Commons (2005) and U.S. Department of Energy (2010).

and EOR technologies have consequently struggled to compete with other investment opportunities available to oil & gas companies (IEA, 2022b). There have cumulatively been over 600 EOR projects around the world since 1959 (Al Adasani and Bai, 2011), with the technology first being applied in the North Sea in the mid-1970s (Gbadamosi et al., 2018).

Eligibility and Adoption. A crucial feature of EOR adoption we rely on in our identification strategy is that not all fields are eligible for the use of this technology. The eligibility of an oil & gas field for the adoption of EOR largely depends on the geological and technological properties of the field, such as the size, depth, and sulfur content of the reservoir; porosity, permeability, and the density of the crude oil; but also the type of platform and drive mechanisms installed for extraction during the early phases of development of the site (Al Adasani and Bai, 2011; Nwidee et al., 2016). Oil & gas fields that do not possess the necessary geological and technological characteristics cannot adopt EOR – even if the operators would in principle be willing to do so.

Conditional on a field being geologically and technologically eligible for EOR, the decision of adoption is then typically made on the basis of forecasts by engineering and economic models. Large oil & gas companies typically have in-house reservoir engineers who create forward-looking models of the reservoirs they are managing. When the reservoir models predict a drop in pressure that will cause problems with the production of the field – like, for example, dropping below the "bubble point" of the oil in the reservoir, which would result in some of the liquid hydrocarbons transforming into the gaseous phase – then EOR is considered. The reservoir engineers then work with the company's petroleum economists to forecast future scenarios to determine whether the considerable expense of applying EOR technologies will result in a net economic benefit in terms of increased production throughout the remaining life of the field.

Whereas the decision to pursue EOR is typically made by a field's oil & gas operator, the operator however overwhelmingly rely on the industry's service companies to provide the specific tools, chemicals, and manpower to carry out the procedures required to implementing EOR. The oil & gas services market is dominated by a small number of large firms that operate globally—such as Baker Hughes, Halliburton, Schlumberger, and Weatherford—but other smaller companies can also be hired to provide some of these services. These service companies' offerings tend to be comparable to each other, and there is therefore a healthy amount of price competition for these services.

2.2 1985 Norwegian Supreme Court Decision

A second key feature of our identification strategy is the comparison of oil & gas fields in UK and Norway, before and after an exogenous Norwegian Supreme Court Decision in 1985 that introduced a substantial difference in the rule of law concerning production licenses in the two countries. To summarize, while the production licenses offered by both countries are very similar (Gordon, 2011), the Norwegian Supreme Court Decision in 1985 established that Norwegian laws limit the ability of the government to retroactively changing certain financial terms of current oil & gas licenses, such as royalty payments. A similar ruling never took place in the UK.

The legal framework. With the Continental Shelf Act of 1963, the Norwegian Government established a licensing system similar to that already in place in the UK (Mestad, 1987). As a result, the legal framework in the two countries is very similar, and views licenses as administrative acts rather than agreements like in the United States. Under the administrative act approach, licenses can be reviewed unilaterally by the administrator (the state party) to the extent that the public interest so dictates. In contrast, licenses cannot be unilaterally changed under the agreement approach. As a matter of fact, more countries grant licenses as administrative acts than agreements across parties (Hunter et al., 2020).[4]

Both in the UK and Norway, regulations specify similar conditions under which licenses are granted, the application process, and the types of licenses. There are two types of licenses, exploratory licenses and production licenses. Exploratory licenses provides the right to explore for petroleum in specified areas for about three years and are renewable. The holder of these licenses has no extraction and production rights, nor any preferential rights when production licenses are granted. Production licenses provide the exclusive right for the exploitation of hydrocarbon resources in the relevant blocks. Production licenses go through three phases. The first phase is the exploration phase, where certain minimum levels of exploratory activities (e.g., seismic surveys, shallow drilling) must be carried out in order to access to the second and third phases, which consist in the development of the drilling infrastructure and, ultimately, the production of oil and gas. The main licensing terms typical of the Commonwealth countries also apply to Norway (e.g., license area, duration, license granting, bidding, licensee's obligation, fiscal regime, participation, relinquishment, settlement of dispute and ownership). See Kardel (2019) for a more in-depth comparative analysis of the two countries.

The Ekofisk case and the Supreme Court's decision. In Norway, royalties can be paid both in-kind and in-cash but, if the license establishes cash payments, the 1965 Petroleum Regulation indicates that payments should be made every six months. The 1972 Petroleum Regulation (Decree, 1972) repealed its 1965 version and, in an attempt to improve the cash flows of the state, imposed quarterly royalty payments without updating the royalty rates. This new payment rule resulted in substantial costs for companies in terms of the lost interest rates due to the increased payment frequency.

Although the state required payments according to this new rule from 1972 onwards, the application of the 1972 Petroleum Regulation was unclear. In 1982, Phillips (today Conoco Phillips), a major oil company, challenged the 1972 regulation, deeming its retroactivity unconstitutional as it was legally unclear whether the new regulation applied only to licenses granted after 1972 or also to older ones. Indeed, applying the new rules to the giant Ekofisk oil field, which was discovered and awarded to Phillips in 1969, increased

[4]For a general discussion of the early history of Norwegian and British regulation see Hanisch and Nerheim (1992) and Gordon (2011), respectively. Details of early licensing and the first Norwegian licensing round in 1965 are described in Bull (1981).

the operating costs at Ekofisk substantially. Several other fields were also interested but decided to wait the outcome of the legal challenge brought up by Phillips rather than engaging in an expensive suit against the Norwegian parliament.

The matter reached the Norwegian Supreme Court in 1985, which issued a legally-binding interpretation in December of the same year (Retstidende, 1985). The Court ruled the unconstitutionality of the reatroactivity clauses of the 1972 royalty scheme and condamned the state to reimburse Phillips for US$32m (or, US$85m in 2022 dollars). After the decision, other affected oil & gas companies operating in other fields other than the Ekofisk area swiftly filed and won law suits to receive a similar treatment.

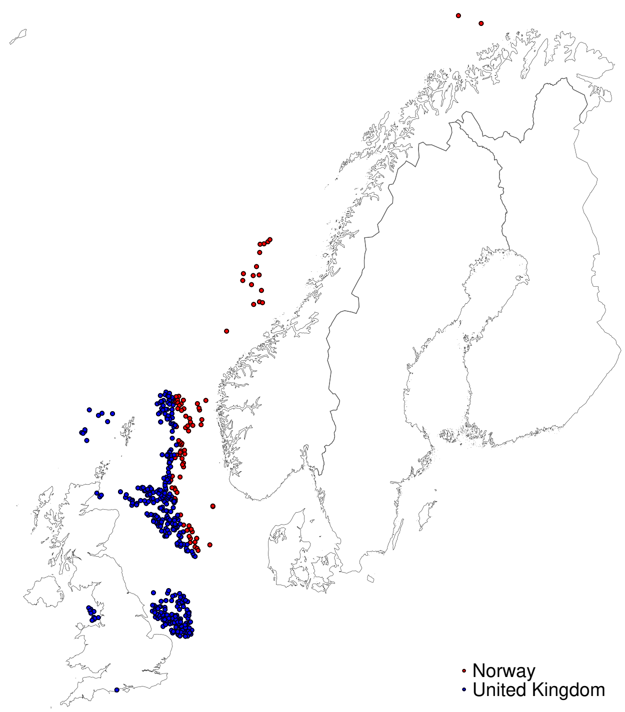
The importance of the ruling is in constraining the ability of the Norwegian Government to freely changing the terms of administrative license contracts (Ulfbeck et al., 2016). In particular, the Supreme Court deemed the royalty change as unreasonably expensive for oil & gas companies and found the government at fault of properly explaining the retroactivity properties of the law, which undermined the need for urgency and collective interest that underlies retroactive amendments to licenses (Mestad, 1987). The interpretation established that "it must be rather clear that the state could not for example change the time limit for a petroleum license without compensation, at least not unless it was based in very urgent need for regulation" (Hunter et al., 2020).

In the UK, similar retroactive rules to those challenged by Phillips existed. These also faced severe opposition, however, neither the English government declined to enforce them nor oil & gas companies challenged their application. For instance, in the space of just over a decade, the UK government made three unilateral amendments to existing licenses, giving them retroactive effect (The Petroleum and Submarine Pipelines Act 1975, the Oil and Gas Enterprise Act 1982, and the Petroleum Act 1987). According to Mestad (1987), the main reason lies in the UK constitutional law, which foresees no cause of action in these situations due to the basic doctrine of "parliamentary sovereignty," which allows the amendment of administrative licenses through simple legislation. In particular, the UK constitution allows for retroactive laws (Parliament of Great Britain, 1793), although criminal laws are prohibited under the European Convention of Human Rights. By contrast, Norwegian licenses are constitutionally protected, and the Supreme Court ruling of 1985 established that they cannot be changed by retroactive laws.

3 Data

In this section, we describe the data we use to study the North Sea upstream oil industry, which was collected by Wood McKenzie, a research and consultancy company specialized in the oil, gas, renewables, chemical, metal, and mining sectors. This unique dataset records information about the upstream oil industry in the North Sea at an extraordinary level of detail, from fields geology, location, production, available technologies, and firm-level operating and capital costs break-downs over the period 1965-2000. The raw data contain information on 576 unique oil & gas fields, 18% of which belong to Norway and 82% to the UK, and 307 unique oil & gas companies. The location and jurisdiction of the oil & gas fields in our sample are displayed in Figure 3.

Figure 3: British and Norwegian oil & gas fields in the Southern North Sea



Note: The figure shows the oil & gas fields in our sample under the jurisdiction of the United Kingdom (blue dots) and Norway (red dots) in the southern portion of the North Sea.

The data record granular information about the geological and technological features of each oil & gas field, which we use to determine their "technical eligibility" for the potential adoption of EOR. Importantly, we observe the size of the reservoir in million barrels of oil equivalent (mmboe), the depth of the reservoir, the sulfur content, porosity and permeability of the field, and the API gravity – a commonly used index of the density of a crude oil. In addition, the data report information on the type of platform and the installed drive mechanism of each field. Following the engineering literature, we are able to identify the most important screening criteria of oil & gas field eligibility for EOR adoption (Al Adasani and Bai, 2011; Nwidee et al., 2016), which are listed in Table 1. The average API gravity in the fields of our sample is 40.66 °F, with little difference between the Norwegian and UK fields. Fields in these two countries are also remarkably similar in terms of reservoir depth, which averages around 2800 meters.

Table 1: Descriptive statistics at field-level: field characteristics

	All	UK	Norway
API Gravity (Fahrenheit)	40.66	40.50	41.24
Reservoir depth (Meters)	2823.87	2820.95	2837.10
Field development			
Share of Fixed platforms	0.39	0.39	0.38
Share of Sub-sea	0.45	0.46	0.40
Field size category			
Share of Giant fields (> 500 mmboe)	0.07	0.07	0.08
Share of Large fields (> 100 mmboe)	0.18	0.19	0.16
Share of Moderate and small fields (< 100 mmboe)	0.75	0.74	0.76
Field depth category			
Share of fields in deep waters	0.01	0.01	0.01
Share of fields in shallow waters	0.99	0.99	0.99

Notes: This table shows technical and geological features of the 521 fields in our final sample. API gravity is a commonly used index of the density of a crude oil, expressed in Fahrenheit degrees, the reservoir depth measures the distance in meters between the reservoir and the seafloor, the field size categories are *Giant*, *Large* and *Medium and Small*, which correspond to the size of the reservoir measured during the exploration phase in million of barrels of oil equivalent, the depth categories are *deep* and *shallow* water, respectively defined as fields where the seafloor is more (less) than 150 meters from the water surface. Field development is the type infrastructure used for oil drilling.

The vast majority of fields are located in shallow waters, i.e, where the seafloor is less than 150 meters from the water surface. The North Sea oil & gas fields are mostly medium to small in size (75%), with a reservoir size of less than 100 mmboe. Large fields represent 18% of observations in the data while giant fields only 7%. Finally, field development solutions in the North Sea are mainly *fixed platforms* (39%) and *sub-sea* (45%). Fixed platform are offshore shallow-water rigs that can be physically attached to the sea floor and sub-sea development refers to an oil or gas development that is physically located on the seafloor, with wells drilled from the water surface using mobile drilling rigs. Table 1 shows that both solutions are equally used in the UK and Norway.

We combine these data on field-level geological and technological features with comprehensive panel data on oil production and costs at the field- and firm-level. For each field and year, the data include information on total yearly oil production in millions of barrels of oil equivalent (mmboe), field age, number of years since the beginning of the drilling, whether and when the field adopted EOR. In addition, we have access to very detailed annual costs data, broken down into operating expenses, capital expenditures and tariff receipts. Table 2 provides detailed statistics of our field-level dataset.

Table 2: Descriptive statistics at field-level: costs and production

	Nb.Obs.	Mean	p25	Median	p75	p95	Std.Dev.
Total costs (M$US)	7727	200.05	12.86	58.61	188.83	887.78	421.98
Capex (M$US)	7727	107.75	0.00	8.16	75.40	536.44	304.81
Opex (M$US)	7727	83.50	2.89	21.26	81.12	341.21	205.10
Production (mmboe/year)	7727	9.72	0.13	1.84	7.90	45.04	24.61
Enhanced Oil Recovery							
Field has EOR	7727	0.06	0.00	0.00	0.00	1.00	0.23
Field is eligible for EOR	7727	0.24	0.00	0.00	0.00	1.00	0.43
Field age							
Years since production	7727	10.08	3.00	8.00	15.00	27.00	8.44
Years since discovery	7727	18.82	11.00	18.00	26.00	35.00	9.78

Notes: This table presents summary statistics of costs and production for our final sample at the field × year level, over the period 1965-2010. The columns p25, p75, and p95 refer to the 25th, 75th, and 95th percentile. Costs are in millions of $US and production is in millions of barrels of oil equivalent per year. Field has EOR (respectively, is eligible to EOR) is a dummy variable equal to 1 if the field uses EOR on year t (respectively, if the field is eligible to EOR). Field age is expressed both in term of number of year of production and number of years since the first exploration of the field.

Our final field-level sample consists of more than 7,700 field-year observations and 521 unique oil & gas fields. The average yearly field production is 9.7 millions of barrels of oil equivalent (mmboe), but the distribution is very skewed. While giant fields' production reaches around 350 mmboe, 50% of the fields in our sample produce less than 2 mmboe/year. We observe the same pattern for costs, with giant fields generating most of the capital expenditures and operational expenses in the North Sea. Despite the fact that one field out of four is eligible according to its geological and technological properties on average, only 6% of fields in our sample adopted EOR to boost oil extraction.

Finally, the data allow us to observe which companies operate in each oil & gas field, their asset interests in the field, their oil production and costs, and whether they are operators or non-operating partners. We then construct a panel at the firm-year level that consists of around 3,200 observations and 281 unique firms. Table 3 describes our

Table 3: Descriptive statistics at firm-level: costs and production

	Nb.Obs.	Mean	p25	Median	p75	p95	Std.Dev.
Total costs (M$US)	3187	484.57	17.31	76.11	428.59	2854.04	1099.19
Capex (M$US)	3187	260.97	5.70	36.20	241.59	1330.35	590.63
Opex (M$US)	3187	202.26	3.68	25.62	142.63	1201.79	515.35
Production (mmboe/year)	3187	23.56	0.31	2.50	16.10	133.72	60.84
Market share	3187	0.01	0.00	0.00	0.01	0.08	0.04
EOR adoption							
Nb. of fields	3187	8.96	1.00	3.00	8.00	43.00	16.00
Nb. of fields with EOR	3187	0.71	0.00	0.00	0.00	5.00	1.87
Nb. of fields eligible for EOR	3187	2.62	0.00	1.00	3.00	14.00	4.53
Share of field with EOR	3187	0.06	0.00	0.00	0.00	0.33	0.15

Notes: This table presents summary statistics of costs and production for our final sample at the firm × year level, over the period 1965-2010. Costs are in millions of $US and production is in millions of barrels of oil equivalent per year. Nb. of fields is the number of oil fields in which the firm operates each year.

firm-level estimation sample.

The average firm in our sample produces 23.5 mmboe per year, and is active in nine fields, one third of which eligible for EOR. The average total costs per year are around US$200m, of which 54% of capital expenditures and 41% of operating expenditures. The remaining 5% are tax receipts, not reported in Table 3. Similar to the field-level data, both production and expenses are skewed: the average firm production equals approximately nine times the median and while some of the firms are active in only one field, others operate in more than 40.

4 Empirical Strategy

This section describes our identification strategy and specifies the regressions we estimate to evaluate (1) the effect of EOR adoption on production, costs, and market structure; (2) whether EOR adoption is affected by know-how or other informational spillovers across oil & gas fields and companies; and (3) if these information channels in turn affect market structure by facilitating further EOR adoption for those who already adopted in the past.

4.1 Identification: EOR Eligibility and Supreme Court Ruling

EOR adoption by the firms operating in a field is non-random and a comparison of production, costs, or market structure before and after the implementation of EOR within a field or across the fields that adopt and those that do not would likely lead to biased estimates. In order to account for potential correlation between EOR adoption and unobservable firm characteristics, such as the risk preferences of managers, we combine two sources of exogenous variation in a triple-difference framework.

First, as discussed in section 2.1, not all oil & gas fields are geologically and technologically eligible for EOR adoption. As described in section 3, our detailed field-level data allow us to determine whether each field is eligible for adoption on the basis of geological features such as API gravity, reservoir depth, and the availability of suitable technological infrastructures such as fixed platforms or drilling developments located on the seafloor (Al Adasani and Bai, 2011, Nwidee et al., 2016). The lack of eligibility of a field for EOR represents a constraint for adoption, irrespective of unobserved firms' characteristics and willingness to do so. However, the eligibility of a field for EOR would not be on its own sufficient to address our endogeneity concerns, in that more productive firms could still self-select into EOR eligible fields on the basis of their willingness to adopt EOR at a later stage. To overcome this challenge, we combine the status of EOR eligibility of a field with an unexpected shock that changed the returns from EOR adoption for fields located in Norway but not in the UK.

In particular, this second source of exogeneous variation we leverage is the (unexpected) Norwegian Supreme Court decision in 1985 discussed in section 2.2. We define as treated the Norwegian fields and the firms that were operating in Norway prior to the Supreme Court decision. Selection into treatment, thus, only indirectly affects EOR adoption because nothing in the legal interpretation offered by the Court directly refers to EOR. Rather, we view the Court decision as a stimulus to capital investment in Norwegian fields motivated by a reduction in the uncertainty of conducting business compared to the UK. Since EOR requires large capital investments, we expect the Court decision to increase EOR adoption and production in Norway relative to the UK, where the threat of retroactive changes to oil & gas licenses may discourage firms to adopt EOR. Therefore, the Supreme Court decision represents an exogenous shock increasing the expected returns of EOR adoption in Norway after 1985, but not in the UK.[5]

To illustrate the relevance of the Supreme Court decision for our purposes, Figure 4 depicts the evolution over time of EOR adoption and oil production across the two countries. Panel (a) shows that the share of EOR fields in Norway rises substantially in the period 1985-1990 and keeps rising to about 30% of available fields, while it was rather flat in the period 1980-1985 prior to the Supreme Court decision. Panel (b) shows a similar

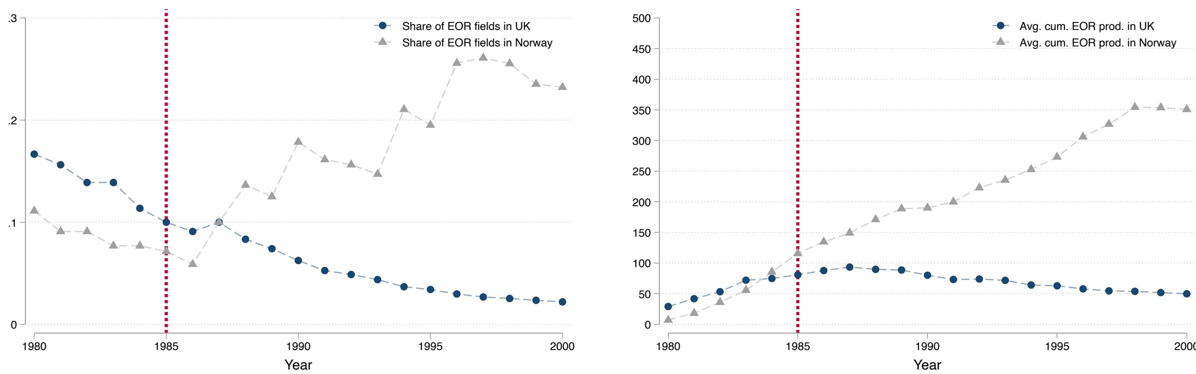
[5] The results that we show in the following analyses also hold if we anticipate the post-period to start in 1982, the year when Phillips initiated the law-suit against the Norwegian Government that ultimately led to the Supreme Court decision in 1985.

departure from the UK trend in average cumulative production by Norwegian EOR fields. Figure A1 in Appendix A shows the relative event-study plots.

Figure 4: EOR adoption and production in Norway and in the United Kingdom

(a) Share of EOR fields

(b) Average cumulative production (mboe)



Note: The figures present the yearly share of fields with EOR by country and the average cumulative production of EOR fields by country between 1980 and 2000. The red dotted lines mark the year of the Supreme Court decision in Norway.

4.2 Field-level Analysis

We combine the two sources of exogenous variation mentioned above in a triple-difference framework. We rely on the Norwegian Supreme Court decision in 1985 to distinguish between treated (Norwegian) and control (UK) fields, and between a pre-period, from 1975 to 1985, and a post-period, from 1985 to 2000, when our database ends. Because of various geological and technological constraints, EOR can only be implemented in fields with suitable features. We then introduce a further layer of comparison among oil & gas fields by exploiting heterogeneity in their *eligibility for EOR in the period prior to 1985.*[6] In particular, for each outcome $y_{f,c(f),t}$ (e.g., production or HHI) measured at the level of field f, country c, and year t, we estimate the following triple-difference regression:

$$\begin{aligned} y_{f,c(f),t} = {} & \beta_{treat}\, \text{Norway}_{c(f)} \cdot \text{EOR}_f \cdot \text{Post}_t \\ & + \beta_1\, \text{EOR}_f \cdot \text{Post}_t + \tau_f + \iota_{c,t} + \varepsilon_{fct}, \end{aligned} \tag{1}$$

[6]While several of the geological and technological features of a field are constant over its life-cycle, some of the crucial ones for EOR eligibility instead evolve over time. For example, the level of pressure in the reservoir naturally falls over time as more of the stock of oil & gas gets extracted (see section 2.1). For all of our analyses, we determine the eligibility of each field for EOR adoption on the basis of its features prior to the Norwegian Supreme Court decision in 1985.

where the indicator $\text{Norway}_{c(f)}$ equals one for fields in Norway and zero in the UK, the indicator Post_t equals one for the years after 1985, and the indicator EOR_f equals one if field f is geologically and technologically eligible for EOR as of 1985 (see section 2.1). Finally, τ_f and $\iota_{c,t}$ are field and country-by-year fixed effects. These country-by-year fixed effects are particularly important to control for the periodic country-level policy changes to which this industry is typically subject (e.g., changes to the royalty schemes).

In this field-level regression, β_{treat} measures the effect of EOR eligibility in Norway after 1985 compared to EOR eligibility in the UK after 1985, controlling for firm and country-year specific effects. The indicator EOR_f captures an intention-to-treat rather than the more direct, but unfortunately endogenous, treatment represented by EOR adoption. As a consequence, β_{treat} can be interpreted as a conservative measure of the effect of EOR adoption, in that many eligible fields both in Norway and in the UK are ultimately not observed to adopt the technology in the time horizon of our sample.

4.3 Firm-level Analysis

In addition to the field-level regressions, we perform the analysis also at the firm-level. This is important to evaluate the consequences of EOR adoption on market structure and competition, in that each oil & gas firm typically (i) operates in multiple fields, (ii) some of which are EOR eligible while others are not, and (ii) operates under both the jurisdictions of Norway and of the UK. Aggregating over fields, for each firm i we define the variable "Share EOR Norway_i" as the average share of Norwegian EOR eligible fields where firm i operates prior to 1985.[7] Similar to the field-level triple-difference regression (1), we estimate the following firm-level regression:

$$y_{it} = \gamma_{treat}\ \text{Share EOR Norway}_i \cdot \text{Post}_t + \alpha_i + \psi_t + \varepsilon_{it}, \tag{2}$$

where y_{it} is an aggregate outcome for firm i in year t across all fields in which i operates, α_i and ψ_t are firm and year fixed effects, and γ_{treat} captures the effect on the outcome of interest of a higher exposure to EOR eligible fields in Norway after the Supreme Court decision. As for the field-level regressions, γ_{treat} can be interpreted as a conservative measure of the effect of a higher exposure to EOR adoption.

[7] Where "prior to 1985" here refers both to the status of a field's eligibility for EOR and to the presence of firm i in a specific field.

5 Consequences of EOR for Adopting Fields and Firms

In this section we study the impact of EOR adoption on (i) the logarithm of production (mboe), (ii) the logarithm of cumulative capital expenditures (capex), (iii) the logarithm of operational expenditures (opex), and the ratios (iv) between production and opex and (v) between production and cumulative capex. Since capex investments do not happen every year and depend on past capex expenditures for related infrastructures within a field, we focus on cumulative rather than current capital expenditures. We first show how these outcomes are affected by EOR eligibility (the intention-to-treat for EOR adoption) at the field-level and then present the analogous results at the firm-level.

5.1 Field-Level Analysis

Table 4 reports the main coefficient estimates from triple-difference regression (1). We find that after the 1985 Norwegian Supreme Court decision, Norwegian EOR eligible fields increased production (Column 1). At the same time, operational costs increased (Column 2), consistent with the need to purchase chemicals for the implementation of EOR. On the one hand, the increase in production is larger than that in opex (Column 4), implying a reduction in average variable costs. On the other, EOR adoption requires capital investments: the cost of adopting the technology increases cumulative capex (Column 3).[8] This illustrates the intuitive trade-off faced by EOR adopters, who must balance lower variable costs (Columns 2 and 4) with large upfront expenses (Columns 3 and 5).

We further investigate the pre-trends through the following regression:

$$y_{f,c(f),t} = \sum_{d=-4}^{d=5} \beta_d \, \mathbb{1}_{\{Treatment_{it}=d\}} + \sum_{d=-4}^{d=5} \zeta_d \, \mathbb{1}_{\{Post_{it}=d\}} + \tau_f + \iota_{c,t} + \varepsilon_{fct}, \tag{3}$$

where $\mathbb{1}_{\{Treatment_{it}=d\}}$ is an indicator equal to one for Norwegian EOR-eligible fields d years before or after 1985 and $\mathbb{1}_{\{Post_{it}=d\}}$ is an indicator equal to one for EOR-eligible fields d years before or after 1985. As in the main specification, τ_f and $\iota_{c,t}$ are field and country-by-year fixed effects.

The estimates for our coefficients or interest β_d are plotted in Figure 5. The panels show that capex increased right after the 1985 decision. Production and opex also increased with a delay between one and two years. Despite their conservative nature, our results are consistent with the timing needed for the implementation of EOR, which can be productive

[8]We focus on cumulative capital expenditures since the capital expenditure in year t might be influenced by the capital expenditures in previous periods.

Table 4: Production and costs by fields

	Prod. (ln) (1)	Opex (ln) (2)	Cum. Capex (ln) (3)	Prod. / Opex (4)	Prod. / Cum. Capex (5)
Norway ×					
EOR × Post	2.941***	2.713***	1.299***	67.065***	0.009***
	(0.318)	(0.516)	(0.365)	(14.734)	(0.001)
Post × EOR	0.634***	1.166***	0.092	31.746***	0.002***
	(0.144)	(0.215)	(0.083)	(11.371)	(0.001)
Country-Year FE	Yes	Yes	Yes	Yes	Yes
Field FE	Yes	Yes	Yes	Yes	Yes
Observations	1503	1502	1503	1503	1474
R-squared	0.63	0.58	0.90	0.48	0.48

* – $p < 0.1$; ** – $p < 0.05$; *** – $p < 0.01$.

Notes: Results of the field-level regression analysis in Equation 1. The indicator variables Norway, EOR, and Post are one for Norwegian fields, for EOR eligible fields, and for the years after 1985 and zero otherwise. Each regression includes country-by-year and field fixed effects. Robust standard errors are presented in parenthesis.

only after the construction of a sufficiently large tank to stock the required chemicals and the purchase of such chemicals. Across panels, we do not observe a pre-trend: prior to the Supreme Court decision, the trends of EOR eligible fields were statistically indistinguishable in Norway and in the UK.

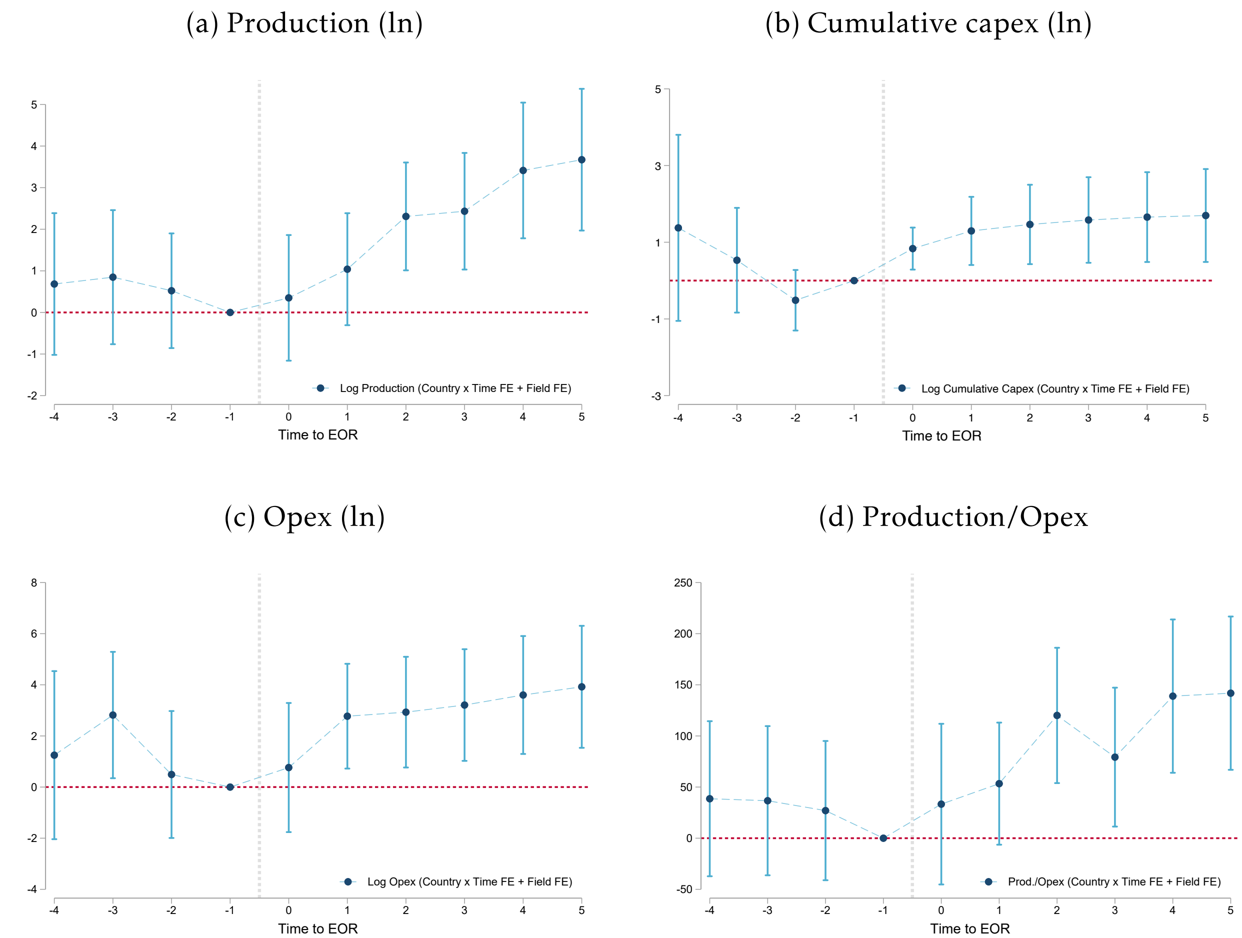
5.2 Firm-Level Analysis

Next, we present our firm-level results obtained on the basis of regression (2). Table 5 presents the estimated effect of EOR eligibility after the Supreme Court decision for various outcome variables. Overall, the results are comparable with those at the field-level presented in the previous section: after the Supreme Court decision, a higher share of eligible fields within Norway increased production (Column 1), opex (Column 2) and cumulative capex (Column 3). Production increased more than opex (Column 4), but not substantially more than capex (Column 5), portraying an analogous trade-off as the one we uncovered at the field-level.

We rely on an event study approach to validate our triple-difference firm-level estimates:

$$y_{it} = \sum_{d=-4}^{d=5} \gamma_d \text{ Share EOR Norway}_i \cdot \mathbb{1}_{\{Treatment_{it}=d\}} + \alpha_i + \psi_t + \varepsilon_{it}, \tag{4}$$

Figure 5: Event Study of production and costs by field



Note: Results of the event study in Equation 3. The Figures shows the coefficients $\hat{\beta}_d$, the impact of being eligible for production d periods in Norway before or after the Supreme Court decision in 1985. $d = -1$ is the reference level. The error bars represent 95% confidence intervals. Standard errors are robust to heteroscedasticity.

where Share EOR Norway$_i$ is the average share or EOR eligible fields of firm i in Norway in the years before 1985 in which firm i was operating prior to 1985 and $\mathbb{1}_{\{Treatment_{it}=d\}}$ is an indicator equal to one when year t happens to be d years before or after 1985, with $d \in [-4, 5]$. We report the event study estimates in Figure 6, which shows similar trends to the field-level event study estimates from Figure 5, with the only difference that the increase in cumulative capex happens with a few years of delay, probably because capex at the firm-level garbles several investment projects that do not necessarily relate to EOR adoption.

Table 5: Production and costs by firms

	Prod. (ln) (1)	Opex (ln) (2)	Cum. Capex (ln) (3)	Prod. / Opex (4)	Prod. / Cum. Capex (5)
Sh. Eligible Norw. Fields × Post	3.237***	3.043***	2.115***	0.283***	0.025***
	(0.371)	(0.249)	(0.399)	(0.060)	(0.002)
Year FE	Yes	Yes	Yes	Yes	Yes
Firm FE	Yes	Yes	Yes	Yes	Yes
Observations	1647	1643	1647	1485	1646
R-squared	0.86	0.86	0.94	0.40	0.40

* – $p < 0.1$; ** – $p < 0.05$; *** – $p < 0.01$.

Notes: Results of the firm-level regression analysis in Equation 2. The variable Sh. Eligable Norway Fields measures a firm's share of Norwegian EOR-eligible fields in the baseline period. The dummy Post takes the value one in years equal or after 1985, the year of the supreme court decision. Each regression includes firm and year fixed effects. Robust standard errors are in presented in parenthesis.

6 Consequences of EOR for Concentration

The results in the previous sections show that our usage of the 1985 Norwegian Supreme Court decision in connection with technical conditions for EOR eligibility capture increased incentives to adopt EOR in Norway. Does however innovation adoption impact competition across firms? In this market, firms compete on two dimensions. While oil & gas firms can hardly affect the global oil prices, they can in any case increase or decrease their oil production given their production technology, which is significantly impacted by EOR adoption. This is the intensive margin of competition. Firms also compete for the production of oil in new fields with untapped resources or can reallocate assets toward fields in which they believe they could operate more efficiently. This is the extensive margin of competition. In this section, we investigate these two margins by studying concentration in field ownership and in the market share of production using the field- and firm-levels triple-difference regressions 1 and 2, respectively.

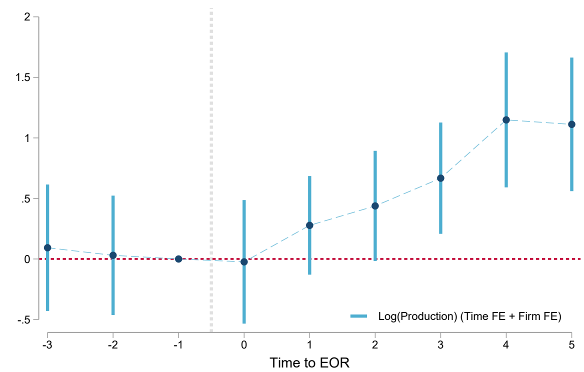
6.1 Field-level Analysis

The starting point of our analysis is asset ownership. As a field becomes more productive after implementing EOR and, potentially, more profitable, do the firms more involved in the ownership of the asset increase their stake in the field? That is, how do firms use the extra cash flows generated by the increased productivity?

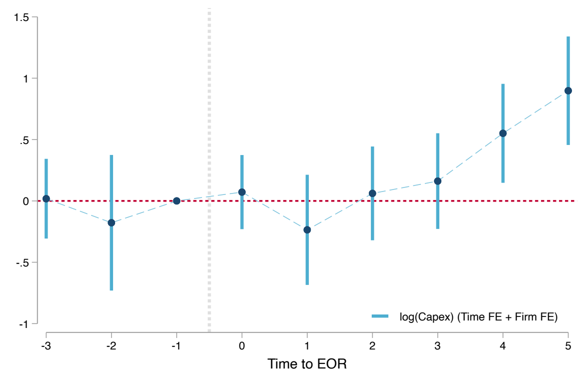
To address these questions, we resort to our triple-difference regression (1) to study

Figure 6: Event Study of production and costs by firm

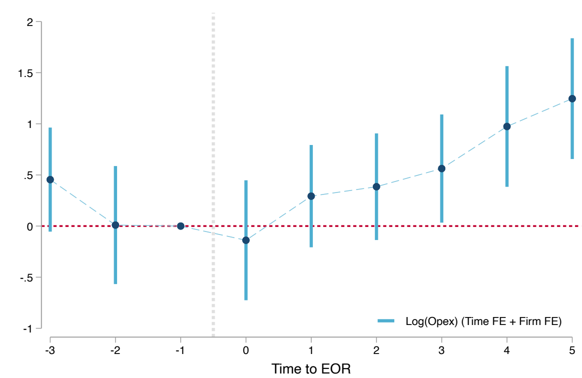
(a) Production (ln)



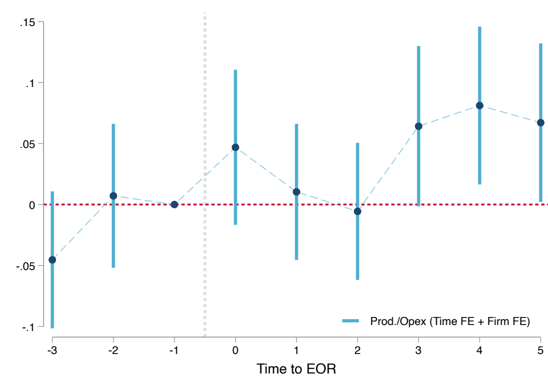
(b) Cumulative capex (ln)



(c) Opex (ln)



(d) Production/Opex



Note: Results of the event study in Equation 4. The Figures shows the coefficients $\hat{\beta}_d$, the impact of being eligible for production d periods in Norway before or after the Supreme Court decision in 1985. $d = -1$ is the reference level. The error bars represent 95% confidence intervals. Standard errors are robust to heteroscedasticity.

whether the HHI measured at the field-level through interest shares changes when incentives to adopt innovative production technologies increase. The first column of Table 6 presents the results: Norwegian EOR eligible fields become more highly concentrated after 1985 compared to EOR eligible fields in the UK. This increase is driven by the acquisition of additional shares by the largest firms already present in the field (Column 4) and, in particular, by the operating firm (Column 3). The latter result highlights the role of specific technical knowledge as a key factor shaping the relationship between innovation adoption and competition. We find no evidence of entry of new firms in the partnership of EOR eligible fields: if anything, the average number of partners decreases slightly (Column 5), which is also consistent with the increase in the normalized HHI (Column 2).[9]

Table 6: Concentration in field ownership

	HHI		Share of		Number of
	Standard	Normalized	Operator	Top 4	Firms
	(1)	(2)	(3)	(4)	(5)
Norway fields × Post × EOR Eligibility	0.228***	0.228***	0.154***	0.456***	-0.200***
	(0.050)	(0.053)	(0.058)	(0.092)	(0.040)
Post × EOR Eligibility	0.032	0.060*	0.061**	0.095**	0.041**
	(0.024)	(0.031)	(0.028)	(0.046)	(0.017)
Country-Year FE	Yes	Yes	Yes	Yes	Yes
Field FE	Yes	Yes	Yes	Yes	Yes
Observations	1502	1351	1355	1502	1502
R-squared	0.63	0.54	0.63	0.41	0.90

* – $p < 0.1$; ** – $p < 0.05$; *** – $p < 0.01$.

Notes: Results of the field-level triple-difference regression (1). The indicator variables Norway, EOR, and Post are one for Norwegian fields, for EOR-eligible fields, and for years from 1985 onward and zero otherwise. The normalized HHI helps comparing HHI across markets when the number of firms vary. The normalized HHI is computed as $\tilde{HHI} = \frac{HHI-1/N}{1-1/N}$. Each regression include country-by-year and field fixed effects. Robust standard errors are in presented in parenthesis.

We investigate the assumptions of this difference-in-differences analysis investigating the pre-trends for HHI and the share of equity held by the operator in Appendix Figure A2: both of its panel show an increase in concentration after 1985.

Assets became more concentrated around the main partners when incentives for adopting new technologies increase. Therefore, the share of oil production of the main partners increased not only because their fields adopted EOR, but also because they increased their ownership share in these assets. The financing of these acquisitions could have originated either from the greater cash-flow following the adoption of EOR or from divestitures from other fields that instead were not eligible for EOR. In the first case, we would expect a firm's market share in the North Sea oil & gas extraction to increase. By contrast, divestitures from other fields may have instead corresponded to lower market shares and concentration. The following firm-level analysis sheds light on these mechanisms.

6.2 Firm-Level Analysis

We rely on the firm-level regression (2) to study whether incentives for technological innovation affect market concentration. The first column of Table 7 shows that firms that

[9]The normalized HHI helps comparing HHI across markets when the number of firms vary. The normalized HHI is computed as $\tilde{HHI} = \frac{HHI-1/N}{1-1/N}$.

were most exposed to Norwegian EOR eligible fields prior to 1985 increased their market share over the oil production in the North Sea after the Supreme Court decision.

The increase in concentration seems to be driven by increased participation in additional fields (Column 2), and especially in EOR eligible fields (Column 4), whose share of oil production in the firm's portfolio increases substantially (Column 5). Notably, the presence of state-owned (S-O) oil companies like Statoil might bias this result in that they could be favored in the allocation of new licenses: removing these firms, however, does not affect the results (Column 3). Supporting these findings, Appendix Figure A3 shows that both market shares and the share of fields with EOR in a firm's asset portfolio increased after the Supreme Court decision.

Table 7: Market structure and competition by firm

	Market Share	Nb. Fields		Nb. EOR Eligible Fields	Share EOR
		w. S-O	(w/o S-O)		
	(1)	(2)	(3)	(4)	(5)
Sh. Eligible Norw. Fields × Post	0.048***	0.557***	0.465***	1.023***	0.388***
	(0.011)	(0.153)	(0.152)	(0.182)	(0.058)
Year FE	Yes	Yes	Yes	Yes	Yes
Firm FE	Yes	Yes	Yes	Yes	Yes
Observations	1647	1647	1597	1647	1647
R-squared	0.80	0.90	0.89	0.79	0.71

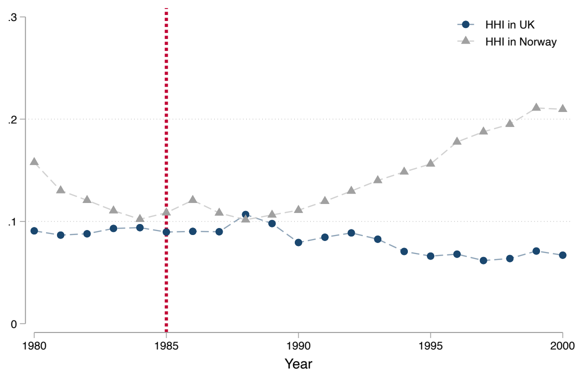
* – $p < 0.1$; ** – $p < 0.05$; *** – $p < 0.01$.

Notes: Results of the firm-level regression analysis in Equation 2. The variable Sh. Eligable Norway Fields measures a firm's share of Norwegian EOR-eligible fields in the baseline period. The dummy Post takes the value one in years equal or after 1985, the year of the supreme court decision. The dependent variable refers to a firm's market share is in Column 1, number of fields in Column 2 (ln), number of fields excluding state-owned (S-O) firms (Statoil and BP) in Column 3 (ln), number of EOR-eligible fields in Column 4 (ln), and Share of EOR-eligible fields among all fields owned by the firm. Each regression includes firm and year fixed effects. Robust standard errors are in presented in parenthesis.

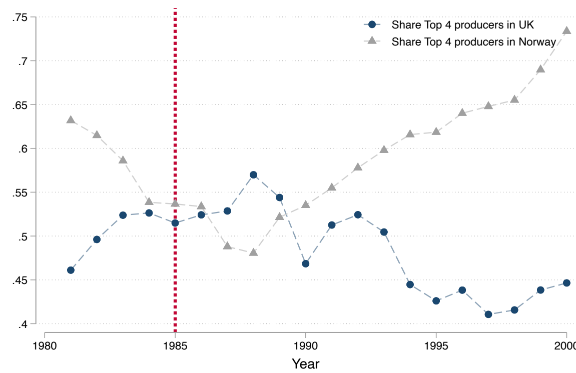
These results are consistent with an increasing specialization of the Norwegian firms, who continued to re-invest the greater cash-flows generated by EOR adoption into the acquisition of other EOR eligible fields without however systematically divesting from ineligible EOR fields. To further corroborate this mechanism, Appendix Table B1 shows that the Supreme Court decision did not result in firms exiting Norway (Column 5). Rather, it resulted in a re-allocation of ownership and increased production at EOR eligible fields, which led to a greater HHI. To appreciate the evolution of market concentration across countries, Figure 7 shows the trends in HHI (Panel a) and the production share of the largest four firms (Panel b) in Norway and in the UK.[10] To highlight the differential trends in concentration, the average post-1985 HHI in Panel a is 0.16 in Norway but only 0.07 in the UK, despite these two values were almost identical in the period leading to the 1985 Supreme Court decision.

Figure 7: Concentration in the oil and gas upstream sector in Norway and UK

(a) HHI



(b) Share of Top 4 firms



Notes: Evolution in cross-country concentration as measured by the HHI (Panel a) and the share of top 4 firms (Panel b). The red dotted lines mark the year of the Supreme court decision in Norway.

To further understand *how* technology adoption affects concentration, the next section investigates the role of past direct and indirect EOR expertise on field ownership and firms' market share, placing particular attention on the extensive margin. In particular, we will distinguish the effect of specialization – a firm with past experience in EOR becoming partners in more EOR fields – and experimentation – a firm with past experience in EOR broadening its asset portfolio – as sources of concentration.

7 Know-how and Spillovers in EOR Adoption

To better understand the mechanism leading to the increase in concentration observed in Figure 7, we investigate whether firms that successfully adopted EOR in some fields carry over the acquired knowledge of the technology to other fields and to their partners. One question is whether an operator who experienced EOR adoption in the past is more likely to re-adopt the same technology in other eligible fields ("know-how"). Another

[10] Appendix Figure A4 shows an even more marked departure across the two countries when the concentration measure is using a version of the HHI statistic that accounts for changes in the number of firms in the market.

related question is whether indirect exposure to EOR by, for example, a partnership with firms that operated fields that successfully adopted EOR can improve EOR uptake rates ("informational spillover"). This section focuses on know-how and informational spillovers as potential drivers of EOR adoption and, consequently, market concentration.

7.1 Effects on EOR Adoption

At the field-level, we consider three main channels to impact EOR adoption. The first obvious candidate is know-how from past EOR adoption on the side of the same operator. For any field f, we define "know-how" as the number of other fields that are also operated by field's f operator that already adopted EOR. This number is averaged over the period 1970-1985. Second, information can also spillover from exposure to the successful experiences of a firm's partners who adopted EOR in other fields. For any field f, we define "informational spillovers" as the ratio of firms that operate both in field f and in other fields f' that already adopted EOR, over the total number of firms that operate in both fields f and f'. As a simple illustrative example, if three firms operate in field A, one of them also operates in field B, and field B already adopted EOR, then the ratio equals 0.25 (1 common firm over 3+1 active firms) – a measure of the intensity of the connection between fields A and B. This value is then summed over all connected fields, and averaged over the period 1970-1985. Finally, information may flow from geographic proximity, as operators may observe successful EOR adoption at neighboring fields and be convinced to adopt themselves.

We investigate these three channels by expanding regression (1):

$$
\begin{aligned}
\mathrm{EOR}_{f,c(f),t} = {} & \beta_{treat}\,\mathrm{Norway}_c \cdot \mathrm{EOR}_f \cdot \mathrm{Post}_t \cdot \mathrm{Knowledge}_f \\
& + \beta_1\,\mathrm{Norway}_c \cdot \mathrm{Post}_t \cdot \mathrm{EOR}_f \\
& + \beta_2\,\mathrm{Post}_t \cdot \mathrm{EOR}_f \\
& + \beta_3\,\mathrm{Knowledge}_f \cdot \mathrm{Post}_t \cdot \mathrm{EOR}_f \\
& + \tau_f + \iota_{c,t} + \epsilon_{fct},
\end{aligned} \tag{5}
$$

where the variable $\mathrm{Knowledge}_f$ refers to one of these three channels.

Table 8 presents the results. The know-how channel is in Columns 1 and 2, the informational spillover channel is in Columns 3 and 4, and the geographical proximity channel is in Columns 5 and 6. Even columns include operator fixed-effects, which help accounting for unobserved differences among operators that do not vary over time but also endogenous operator changes over time.

Across columns, we find that previous experience is a key determinant of technology adoption. Differently, partnerships with firms that adopted EOR in other fields lead to mixed results. The coefficient estimates in Column 3 and 4 are positive and large, indicating that information from partners does increase EOR adoption. However, the magnitude of the standard errors calls for a cautious interpretation. Finally, the estimates also undermine geographic proximity as a potential facilitator of EOR adoption (Columns 5 and 6). Overall, of the three information channels, know-how appears to be the most convincing in explaining EOR adoption rates. Combining this insight with the results from section 6, in the next section we investigate whether know-how or informational spillovers may lead to higher market shares and market concentration through an extensive margin impact on EOR adoption.

Table 8: The impact of know-how and information spillovers on EOR adoption

Dependent Variable:	Has EOR in year t (0/1)					
Channel:	Know-How		Spillover		Proximiy to EOR	
	(1)	(2)	(3)	(4)	(5)	(6)
Main variables:						
Operator with EOR × Norway fields × Post × EOR Eligibility	0.742***	0.749***				
	(0.115)	(0.112)				
Shareholders with EOR × Norway fields × Post × EOR Eligibility			1.155	1.143		
			(0.751)	(0.748)		
Avg. inverse distance to EOR × Norway fields × Post × EOR Eligibility					-0.228	-0.332
					(1.718)	(1.706)
Interaction terms:						
Norway fields × Post × EOR Eligibility	0.065	0.018	-0.278	-0.314	0.232	0.203
	(0.138)	(0.137)	(0.350)	(0.343)	(0.264)	(0.261)
Post × EOR Eligibility	0.135**	0.149**	0.149**	0.166**	0.019	0.020
	(0.064)	(0.068)	(0.074)	(0.079)	(0.024)	(0.026)
Operator with EOR × Post × EOR Eligibility	-0.094**	-0.103**				
	(0.046)	(0.048)				
Shareholders with EOR × Post × EOR Eligibility			-0.182*	-0.202*		
			(0.096)	(0.102)		
Avg. inverse distance to EOR × Post × EOR Eligibility					0.724	0.768
					(0.469)	(0.490)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
Field FE	Yes	Yes	Yes	Yes	Yes	Yes
Operator FE	No	Yes	No	Yes	No	Yes
Observations	1292	1290	1292	1290	1292	1290
R-squared	0.85	0.86	0.85	0.86	0.85	0.85

* – $p < 0.1$; ** – $p < 0.05$; *** – $p < 0.01$.

Notes: Results of the field-level regression analysis in Equation 5. The top panel shows the estimates of the main coefficient ($\hat{\beta}_{treat}$), whereas the bottom panel shows the estimates of the remaining interactions. The variable Knowledge$_f$ varies across columns according to the column header. The indicator variables Norway, EOR, and Post are one for Norwegian fields, for EOR-eligible fields, and for years from 1985 onward and zero otherwise. Each regression include country-by-year and field fixed effects, while even columns also include operator fixed effects. Robust standard errors are in presented in parenthesis.

Table 9: The impact of know-how and information spillovers on field concentration

Dependent Variable:	HHI at the field-level computed using firms' ownership shares					
Channel:	Know-How		Spillover		Proximiy to EOR	
	(1)	(2)	(3)	(4)	(5)	(6)
Main variables:						
Operator with EOR × Norway fields × Post × EOR Eligibility	0.380***	0.368***				
	(0.085)	(0.087)				
Shareholders with EOR × Norway fields × Post × EOR Eligibility			-0.276	-0.272		
			(0.465)	(0.464)		
Avg. inverse distance to EOR × Norway fields × Post × EOR Eligibility					-1.430	-1.295
					(0.914)	(0.889)
Interaction terms:						
Norway fields × Post × EOR Eligibility	0.076	0.069	0.252	0.246	0.248	0.232
	(0.094)	(0.099)	(0.214)	(0.217)	(0.151)	(0.150)
Post × EOR Eligibility	0.054	0.037	0.050	0.037	0.032	0.020
	(0.068)	(0.067)	(0.074)	(0.073)	(0.074)	(0.072)
Operator with EOR × Post × EOR Eligibility	-0.008	-0.014				
	(0.040)	(0.040)				
Shareholders with EOR × Post × EOR Eligibility			-0.003	-0.021		
			(0.098)	(0.093)		
Avg. inverse distance to EOR × Post × EOR Eligibility					0.204	0.095
					(0.413)	(0.363)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
Field FE	Yes	Yes	Yes	Yes	Yes	Yes
Operator FE	No	Yes	No	Yes	No	Yes
Observations	1292	1290	1292	1290	1292	1290
R-squared	0.65	0.69	0.64	0.69	0.64	0.69

* – $p < 0.1$; ** – $p < 0.05$; *** – $p < 0.01$.

Notes: Results of the field-level regression analysis in Equation 5. The top panel shows the estimates of the main coefficient ($\hat{\beta}_{treat}$), whereas the bottom panel shows the estimates of the remaining interactions. The variable Knowledge$_f$ varies across columns according to the column header. The indicator variables Norway, EOR, and Post are one for Norwegian fields, for EOR-eligible fields, and for years from 1985 onward and zero otherwise. Each regression include country-by-year and field fixed effects, while even columns also include operator fixed effects. Robust standard errors are in presented in parenthesis.

7.2 Effects on Market Concentration

In this section, we evaluate whether various information channels indirectly affect competition through an increase of EOR adoption. In a first set of field-level analyses, we estimate regressions akin to (5) in which we use a measure of field-level HHI in terms of firms' interest shares as dependent variable. Table 9 reports these estimation results. Consistent with the results from Table 8 on the effects of information on EOR adotion, only know-how appears to have a positive and statistically significant effect on field-level concentration, corroborating the idea that accumulated technical experience on past EOR projects leads firms to further expand their influence in other EOR eligibile fields, reinforcing their presence in the oil & gas industry in the North Sea (Columns 1 and 2). To confirm whether a larger field-level concentration also corresponds to an increase in the share of total production by these firms, we next investigate the effects of three information channels on firm-level market shares.

Firms may learn about EOR adoption both directly, from their own past experience as operators, and indirectly, from the choices of partner operators. We then distinguish between "direct know-how," which we measure as the number of fields in which the firm adopted EOR as an operator in the period prior to 1985, and "indirect know-how," which we measure as the number of fields in which the firm experienced EOR adoption by a partner operator in the period prior to 1985. We also define "informational spillovers" as the number of fields in which partners of the firm adopted EOR in the period prior to 1985 but where the firm was not active.[11]

To determine the impact of these three channels on market shares, we rely on the following regression:

$$\begin{aligned} y_{i,t} = &\gamma_{direct} \text{ Share EOR Norway}_i \cdot \text{Post}_t \cdot \text{Direct Know-how}_i \\ &+ \gamma_{indirect} \text{ Share EOR Norway}_i \cdot \text{Post}_t \cdot \text{Indirect Know-how}_i \\ &+ \gamma_{spillover} \text{ Share EOR Norway}_i \cdot \text{Post}_t \cdot \text{Spillover}_i \\ &+ \gamma \text{ Share EOR Norway}_i \cdot \text{Post}_t \\ &+ \alpha_i + \psi_t + \varepsilon_{it}. \end{aligned} \tag{6}$$

Table 10 reports the coefficient estimates. Column 1 uses a firm's market share as dependent variable and shows that a direct past experience as operator dealing with EOR adoption increases market shares by 7% (first row). The remaining two channels instead do not increase market shares. The higher market shares result from a larger number of the EOR eligible fields in which firms with direct and indirect know-how decide to enter (Column 2). However, these firms re-invest the greater cash-flow they receive not only in EOR fields, but also diversify their asset portfolio by investing in fields that are EOR-ineligible (Column 3).

We investigate the investments of firms with know-how and informational spillovers in the last three columns of Table 10, where we examine whether these firms are more likely to enter less common fields. In particular, we focus on the change in the (log) number of heavy oil fields, sour oil fields, and ultra-deep oil fields in a firm's portfolio after the 1985 Supreme Court decision in Columns 4, 5, and 6, respectively. Heavy oil is a costlier oil to extract and process because of its low API – conventional oil has API above 20°F, while heavy oil has lower acidity levels. Sour oil instead has sulphur contents over 0.5%, according to the New York Mercantile Exchange. Finally, the last column considers as deep oil all ultra-deep oil fields with average depths greater than 7,000 feet (or 2,130 meters). Extracting oil under these conditions is more costly and requires different technologies. Therefore, we take differential entry in these fields as a test of the ability of firms with past EOR experiences to adopt other new technologies.

[11] We discard geographic proximity because we find that its impact is negligible at the field-level (Table 8) and because the average distance to fields adopting EOR does not lead to an intuitive interpretation.

Table 10: The impact of know-how and spillovers on firms' market shares and portfolios

	Market Share (1)	Nb. EOR Fields (ln) (2)	Share of EOR fields (3)	Nb. Heavy Oil Fields (ln) (4)	Nb. Sour Oil Fields (ln) (5)	Nb. Deep Oil Fields (ln) (6)
Direct Know-how × Sh. Eligible Norw. Fields × Post	0.070***	1.654***	-0.338***	0.714***	2.676***	1.202***
	(0.018)	(0.299)	(0.079)	(0.165)	(0.257)	(0.250)
Indirect Know-how × Sh. Eligible Norw. Fields × Post	-0.009	1.194***	-0.257***	0.342***	1.118***	0.428**
	(0.011)	(0.228)	(0.058)	(0.109)	(0.205)	(0.191)
Spillover × Sh. Eligible Norw. Fields × Post	-0.005	0.093	0.059**	-0.046**	-0.396***	-0.010
	(0.007)	(0.108)	(0.028)	(0.023)	(0.113)	(0.153)
Sh. Eligible Norw. Fields × Post	0.055**	0.935***	0.316***	0.069	0.666**	0.420
	(0.022)	(0.341)	(0.087)	(0.053)	(0.265)	(0.480)
Year FE	Yes	Yes	Yes	Yes	Yes	Yes
Firm FE	Yes	Yes	Yes	Yes	Yes	Yes
Observations	1647	1647	1647	1647	1647	1647
R-square	0.81	0.80	0.72	0.38	0.85	0.87

* – $p < 0.1$; ** – $p < 0.05$; *** – $p < 0.01$.

Notes: Results of the firm-level regression analysis in Equation 6. Direct know-how is measured as the number of fields where a firm is an operator that adopted EOR in the baseline period. Indirect know-how is the number of fields that adopt EOR where the firm is not an operator in the baseline period. Spillover is also measured at baseline as the number of fields that implemented EOR where the focal firm is not active but that are related to the focal firm because at least one of the owners of the field are in a partnership with the focal firm in another field. The variable Sh. Eligable Norway Fields measures a firm's share of Norwegian EOR-eligible fields in the baseline period. The dummy Post takes the value one in years equal or after 1985, the year of the supreme court decision. Dependent variables are defined in the column headers – "heavy oil" refers to fields with average acidity below 20°F, "sour oil" refers to fields with average sulphur content above 0.5%, and "deep oil" refers to ultra deep fields with average depth below 7,000 feet (2,130 meters). Each regression includes firm and year fixed effects. Robust standard errors are in presented in parenthesis.

The last three columns explain the drop in the share of EOR fields across the fields owned by firms with direct or indirect know-how (Column 3) in terms of a taste for more complex fields. These firms are found to enter heavy, sour, and (ultra-) deep fields after the 1985 Supreme Court decision. Once again, we detect no impact for informational spillovers: only past knowledge matters. Therefore, our approach indirectly infers another novel mechanism for adoption to increase market share: firms with successful technology adoption are also more likely to adopt other new technologies. It is important to note that the EOR technology was freely available to all firms in the market before the Supreme Court decision, as EOR was not proprietary to any firm. Since firm characteristics like their patent portfolio or experiences in other parts of the world are orthogonal to the 1985 Supreme Court decision, our analysis implies either a drop in risk aversion or a greater appeal for riskier projects for firms with successful direct past experiences at adopting novel technologies, namely, firms with past direct- or indirect-know-how in Norwegian waters before 1985. We discuss these results in the next section.

8 Discussion

This paper sheds light on the causal impact of technological adoption on competition. We focus on the oil and gas upstream sector because it provides us with several advantages that help us in accounting for the endogeneity in adopting innovative technologies. First, we take advantage of a unique dataset with detailed yearly information about capital and operational expenses, production levels, and ownership status of the fields in the southern portion of the North Sea (UK and Norway). We also observe fixed field characteristics such as different oil qualities (e.g., its acidity), the depth of the field, and its geology. We use this information to distinguish fields that are technically eligible to install the Enhanced Oil Recovery (EOR) technology according to oil engineering requirements (Al Adasani and Bai, 2011, Gbadamosi et al., 2018). Second, our focus on EOR is due to its revolutionary impact on the oil industry: the average recovery rate is hardly greater than 40% of a field's reservoir without EOR (e.g., Sandrea and Sandrea, 2007, IEA, 2008b), while it can reaches up to 70% with EOR (e.g., McGuire et al., 2000, Toole and Grist, 2003, Muggeridge et al., 2014). Third, we exploit a policy shock, a 1985 Norwegian Supreme Court decision, which limited the powers of the Norwegian government to amend oil and gas licenses to its advantage unilaterally. This decision acts like a cost-shifter, reducing the uncertainty about future returns to current capital investments in Norway but not in the UK. To motivate our analysis, we document a steep increase in EOR adoption across the fields in the former but not in the latter country. Fourth, focusing on a homogeneous good market, we preempt technology adoption as a source of product differentiation, further reducing potential endogeneity issues.

Using a triple difference-in-differences approach accounting for differences across EOR- eligible and ineligible fields, UK and Norwegian fields, and before and after the 1985 Supreme Court decision, we initially show in Table 4 that after the 1985 Norwegian Supreme Court decision, Norwegian EOR eligible fields increased production after 1985. At the same time, operational and capital expenses also increased. Comparing the increase in production and each expense, we find that gains in production outweigh operational costs, but not capital expenditures. The results are similar when considering firm-level outcomes instead (Table 5), where we exploit variation in a firm's share of fields being eligible for EOR in the period leading to the Supreme Court decision in 1985 to define treated and control firms. Intuitively, a firm with an EOR eligible field faces a tradeoff typical of technology adoption problems: future production becomes more efficient at the cost of an increase in current expenditures.

Our main finding is that this production surge affects concentration at the firm and at the field level. At the field level, Table 6 shows that fields, which are commonly owned by multiple firms but operated by one firm only, become more concentrated around the operating firm after 1985. Although we do not observe mergers and acquisition transactions but only changes in equities, this finding indicates that operating firms may be leveraging their greater knowledge about their field's operations (and EOR usage) and decide to buy the shares of non-operating partners as their expectation of the future cash flows from the field are higher than those held by non-operating partners. Consistent with this thesis, we show that Norwegian firms with greater shares of EOR fields before 1985 increased their market share in the North Sea after 1985. Therefore, not only do these firms use the greater cash flows from their EOR fields to buy out their partners in their pre-existent EOR fields, but they also engage in more exploration, and their bids for new licenses are more likely to be accepted.

Importantly, bidding for licenses follows similar rules in the UK, and Norway (Kardel, 2019): in both countries, licenses are allocated through a bargaining process between firms and the government, which is not bound by specific scoring rules but rather maintains extensive discretionary powers. For instance, the Minister would reserve full capabilities to reject any application, and potential applicants are expressively invited to discuss their operative plans (Kemp, 2013) In particular, the royalty amount is not the only determinant of an application. Instead, governments place large values on the ability of an applicant to leave the least amount of resources in the ground. Thus, firms with successful EOR experiences are in a better position to document their skills. Therefore, this extensive margin, more than the obvious effect of a drop in cost of production, may be responsible for the observed increase in concentration (Figure 7).

We consider several channels that might be responsible for EOR adoption and, in turn, the market share changes. We consider the know-how arising from past EOR experiences (whether directly, as an operator, or indirectly, as a partner in a field with EOR), the spill-over effects from partnering with fields that adopted EOR in other fields, and the geographic proximity to fields that adopted EOR. Table 8 shows that a field's EOR adoption decision only responds to past know-how. In contrast, we find no evidence for analogous information spill-overs across firms or any indication of the effect of geographic proximity. Thus, only past experience with EOR of the fields' partners creates value for the field since this analysis only includes fields existing before 1985, thereby excluding the possibility for firms to enter new EOR-eligible fields. As a result, these fields also become more concentrated as measured by the HHI (Table 9) through the know-how channel.

Shifting our focus from fields to firms, our analysis reveals a novel mechanism for innovation to reduce consumer welfare. Previous research shows that product cannibalization may be one such factor leading to greater concentration (Igami and Uetake, 2020), but, due to our focus on an industry for homogenous goods and horizontal residual demand, this effect might not be in place. Instead, we show in Table 10 that a firm's direct know-how as the operator of EOR-eligible fields can be a source of concentration. Firms with such know-how in the baseline period owned more producing assets after 1985 than similar firms without such know-how and saw their market share grow substantially. In addition, past know-how leads firms to experience new technologies as we show that the asset portfolios of these firms turns to riskier and costlier fields such as those where oil is heavier, contains more sulphur, or that are classified as ultra-deep (7,000 feet or deeper).

Our results indicate that successful past adoption increases concentration through specialization (more EOR) and, at the same time, more experimentation in riskier projects. These firms appear to become less risk-averse, which renders them more dynamic and ultimately increases their market share through the extensive margin discussed above. Unlike know-how, information spillovers do not seem to affect either specialization or experimentation, suggesting that mere observation is not enough to affect a firm's business practices. These findings are of great importance for the energy industry, as, looking forward, EOR coupled with carbon storage technologies represents an opportunity to decarbonize the energy sector (IEA, 2022a) but could also apply more broadly to other industries where firms face a downward sloping residual demand, which might create even more scope for concentration compared to our case.

Therefore, in industries where adequate market competition is a driver of welfare – Asker et al. (2021) show a massive welfare loss due to the presence of a cartel in this industry – innovation adoption may play an important role at improving firms' productivities and enhancing competition – for instance, by moving the frontier of what fields are economical to drill. However, the process of knowledge accumulation gives already adopting firms a greater ability to roll out new technologies at several production plans (e.g., Collard-Wexler and De Loecker, 2015), which can deter competition by, for instance, reducing the entry of new firms.[12] Zooming in on the oil and gas sector, it might be harder for these firms to win exploratory licenses because they cannot show the government a successful track of technological adoption. In other industries, an entry might be limited by high fixed costs due to, for instance, the lack of key patents.

9 Conclusion

Our analysis sheds light on the causal impact of technological adoption on productivity and competition. Our results show that technological adoption requires large upfront costs but that it also leads to proportionally higher increases in production. In aggregate, these production increases induce an increase in market concentration.

[12] Appendix Table B1 shows that, at the country level, fewer firms entered Norway after 1985 than UK (Column 4), but does not detect any significant difference in the number of exiting firms (Column 5). The first three columns use different measures of concentration to highlight the drop in competition in Norway.

We show that this increase in market concentration is driven not only by the direct effect of higher productivity of the fields that adopt EOR (intensive margin), but also by the indirect effect of an expansion in the number of EOR eligible fields in which adopting firms decide to enter (extensive margin). In particular, firms with previous direct experiences of EOR adoption increase their market share. The aggregate increase in market share is due to two effects. First, we observe an immediate effect of EOR adoption as EOR increases production. This direct effect is not surprising, as EOR is designed to increase the productivity of adopting fields. Second, EOR adoption increases the know-how of adopting firms, which leverage on it and further expand their portfolio of EOR eligible fields (specialization) and more complex and riskier fields (experimentation). In contrast, we find no evidence of analogous information spill-overs across firms.

Our results unveil some novel mechanisms through which technological innovation may impact competition and can inform the design of more effective innovation and antitrust policies. While innovation increases productivity, it can also harm competition, especially in contexts – like the one we study – in which technological adoption is costly, but an accumulation of know-how may facilitate it. Innovation and innovation adoption could reduce aggregate welfare in markets where competition is important to generate welfare for all participants while increasing productivity. For industries in which innovation plays a central role, antitrust policy could increase competition standards to prevent agglomeration and unintended welfare reductions.

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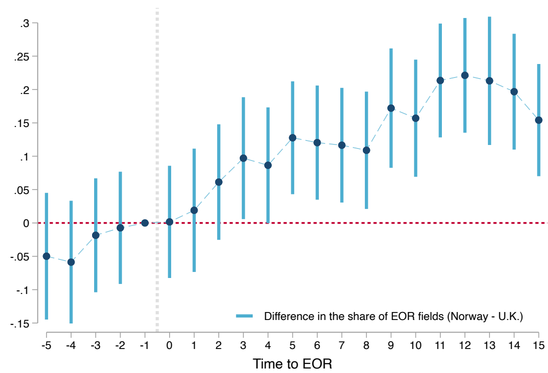
Online Appendix

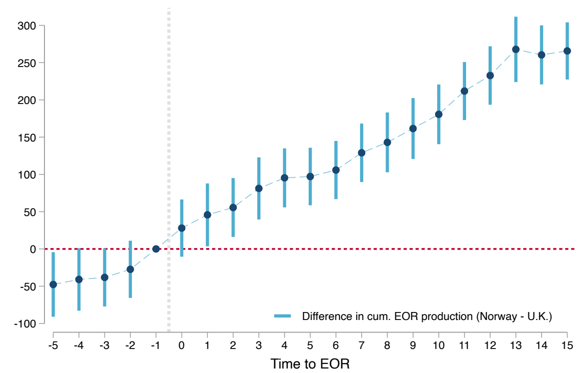
A Omitted Figures

Figure A1: EOR adoption and production in Norway and the United Kingdom, event study

(a) Share of EOR fields



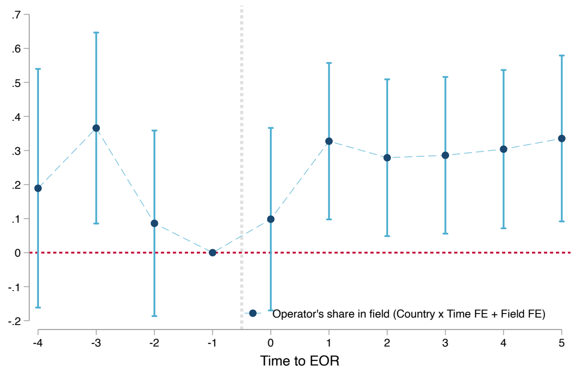
(b) Average cumulative production (mboe)



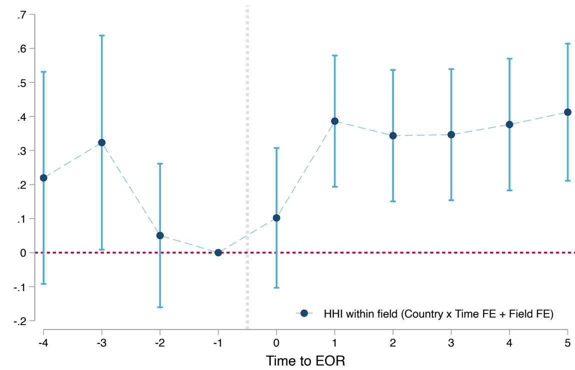
Note: The figures present the event study for the yearly share of fields with EOR by country and the average cumulative production of EOR fields by country between 1980 and 2000. The red dotted lines mark the year of the Supreme court decision in Norway. The regressions include country global oil prices and its squared value and country fixed effects.

Figure A2: Concentration within a field

(a) HHI



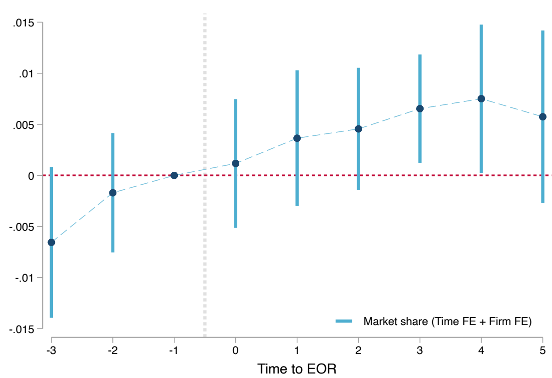
(b) Interest share to the operator



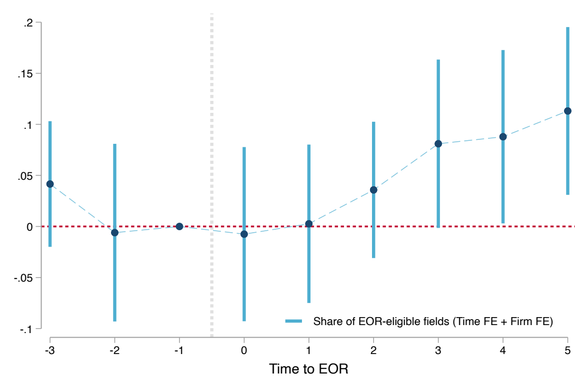
Note: The event study from Equation 3 using either the HHI computed using the share interests of the firms that invested in a field (Panel a) or the share interest of a field's operator (Panel b). The bars report the 95% confidence intervals. The regression includes country-by-year and field fixed effects.

Figure A3: Concentration at firm-level and EOR adoption

(a) Market share



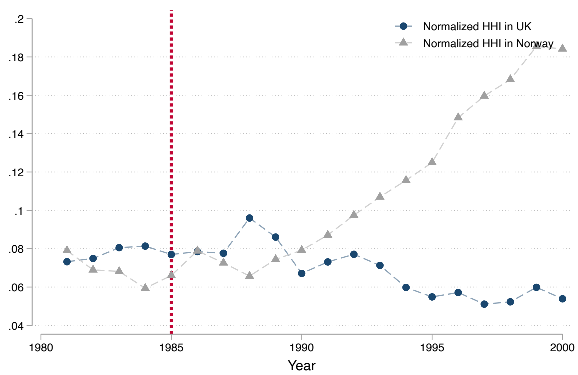
(b) Share of fields adopting EOR



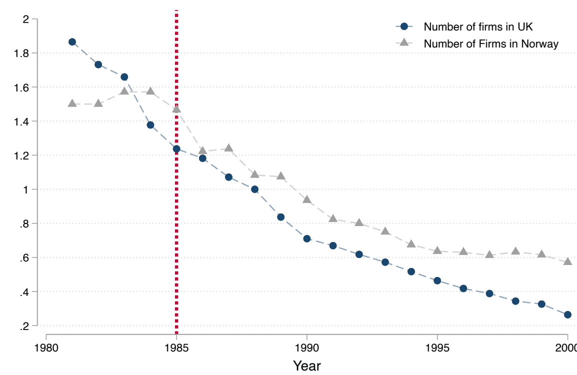
Note: The event study from Equation 4 using either a firm's market share (Panel a) or the share of EOR-eligible fields (Panel b). The bars report the 95% confidence intervals. The regression includes country-by-year and field fixed effects.

Figure A4: Concentration accounting for entry/exit

(a) HHI (normalized by the number of firms)



(b) Number of firms



Note: Panel a shows the evolution in cross-country concentration using the normalized HHI ($\frac{HHI-1/N}{1-1/N}$, where N is the number of firms). Panel b shows the trend in the number of firms.

B Omitted Tables

Table B1: Concentration measures at the country level

	HHI	Normal. HHI	Share of Top 4	Number of Entering Firms	Number of Exiting Firms
	(1)	(2)	(3)	(4)	(5)
Norwegian fields × Post	0.038**	0.052***	0.006	-1.482**	-2.306
	(0.016)	(0.016)	(0.049)	(0.715)	(1.649)
Country FE	Yes	Yes	Yes	Yes	Yes
Year FE	Yes	Yes	Yes	Yes	Yes
Observations	42	42	42	42	42
R-squared	0.70	0.57	0.54	n.a.	n.a.

Note: Results of the country-level regression analysis:

$$y_{ct} = \text{Norway}_c \cdot \text{Post}_t + \phi_c + \tau_t + e_{ct},$$

where Norway is a dummy that is one for Norway and 0 for the UK and Post is an indicator that is one for years greater than 1985 and zero otherwise. The dependent variables are defined in the header. Columns 1, 2, and 3 show results from OLS regressions, while Columns 4 and 5 show results from negative binomial regressions. The normalized HHI (Column 2) is computed as $\frac{HHI-1/N}{1-1/N}$, where N is the number of firms. Each regression include country-by-year and field fixed effects. Robust standard errors are in presented in parenthesis.