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The Welfare Implications of Oil Privatisation: A Cost-Benefit Analysis of Norway's Statoil

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Keywords Privatisation, Cost-Benefit, Welfare, Oil and Gas, Norway

JEL Classification D61, H43, L33, L71, Q48

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THE WELFARE IMPLICATIONS OF OIL PRIVATISATION: A COST-BENEFIT ANALYSIS OF NORWAY'S STATOIL

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1 Introduction

The oil and gas industry is of great economic significance to many countries, and privatisations of National Oil Companies (NOCs) have often been controversial, as have been the benefits from privatisation more generally.[1] Privatisation certainly offers substantial opportunities to private buyers, but there is concern whether such gain comes at the expense of other groups, most notably the selling state, consumers and employees, and results in aggregate welfare losses. This ambivalence is also reflected in empirical privatisation studies, of which three basic types exist: (1) studies comparing privately owned firms with (different) publicly owned firms (Boardman and Vining 1989); (2) studies of corporate performance and efficiency throughout a privatisation process (D'Souza and Megginson 1999); and (3) social cost-benefit analyses of privatisation (SCBA) (Galal et al. 1994).[2] The balance of evidence from the first two types of studies suggests superior performance and efficiency in the private sector (Megginson and Netter 2001). But critics of privatisation view such findings as inherent to fundamentally different objective functions of the firm, and argue that the social costs of private ownership fail to be captured by narrow measurements of profitability (Bozec et al. 2006). SCBA is able to resolve many of such concerns – it takes into account institutional changes other than ownership, implicitly includes a control group, and focuses on a broad measure of social welfare – as long as a convincing counterfactual scenario (the hypothetical outcome under continued state ownership) can be constructed.

In this paper we use SCBA to estimate the overall welfare changes from the partial privatisation of Norwegian NOC Statoil in 2001, and to investigate the distribution of costs and benefits among government, producers and consumers. Statoil is a suitable case study within the oil and gas industry – its corporate performance improvement during privatisation was below-average but directionally in line with the wider sample of global oil privatisations (Wolf 2008b; Wolf and Pollitt 2008)[3] – but also relevant

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[1] For supporters of private markets public ownership *per se* results in lower economic efficiency; control should thus be transferred to the private sector, and regulation should address market failures (Shleifer and Vishny 1998). Others point out the pervasiveness of market failures, the costliness and imperfectness of regulation, and the potential benefits of direct state involvement (Stiglitz 2007). Laffont and Tirole (1993) conclude that theory on its own is unlikely to provide a definitive answer.
[2] These methodologies are discussed in Newbery and Pollitt (1997) and Boardman et al. (2007). Reviews of the empirical evidence include Megginson and Netter (2001) and Kikeri and Nellis (2002).
[3] It is in fact in the bottom third of that peer group, hence a rather conservative choice.

for the broader privatisation debate. It is Norway's largest industrial enterprise and is operating the majority of the national hydrocarbon output – Norway is one of the key exporters in the global oil and gas markets, the sector being of great national economic importance. As of July 2008 Statoil had a market capitalisation of more than US$ 110 billion. Furthermore, the transaction exhibits a typical sale structure – partial privatisation without initial control transfer (Perotti and Guney 1993) – which enables a test of Galal's observation that "partial divestiture can provide gains that equal those of full divestiture" (1994, p.5).[4] Finally, although Norwegian institutional governance can be expected to prevent any blatant abuse of the privatisation process[5], it is also not obvious that a decently run state firm such as Statoil has much to gain from privatisation. As Joseph Stiglitz (2007, p.30) sceptically remarks: "By most accounts, Norway's state oil company was both efficient and incorruptible; probably few countries have been able to realize for its citizens a larger fraction of the potential value of a country's resources. In the case of Norway, institutional change may make little difference in either direction (…). Norway's story is important because it destroys the shibboleth that efficiency and welfare maximisation can be obtained only through privatization."

To our knowledge this paper represents the first privatisation SCBA within the global oil and gas industry, which provides a fertile context for studies of ownership change and welfare generation. Firstly, the industry remains economically and politically important, and its role has been further strengthened in recent years. Secondly, oil and gas has been, together with utilities and telecommunications, one of the key contributing industries to overall privatisation revenues (Megginson 2005). Thirdly, although a number of private oil and gas companies rank amongst the largest corporations in the world, the large majority of the world's hydrocarbon reserves are under the control of nation states and their NOCs (PIW 2007). With dramatic increases in energy prices some countries are even considering revisions to previous choices in favour of private ownership. And fourthly, despite their importance there

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[4] As Gupta (2005) points out, this represents a test of competing theories on the underperformance of state-owned firms: the *political* view emphasises distorted objectives, which can only be remedied though a transfer of control, whereas the *managerial view* (based on agency theory) emphasise the lack of stock-market monitoring. Studies of full privatisation are unable to distinguish between these two theories, whereas successful partial privatisation supports the latter view.

[5] Norway is certainly not a typical oil exporting country in terms of institutional context, but the analysis in Wolf (2008b) showed that better country-level governance is *negatively* correlated with oil company performance improvement during privatisation.

has been surprisingly little systematic research on NOCs in general (McPherson 2003), and on the link between ownership, performance and welfare generation in particular.[6] From a methodological perspective, this paper is one of the few SCBAs where the counterfactual scenario can be based on a truly comparable, privately controlled competitor subject to the same external environment. The granularity of the available cost data also allows an analysis at the level of main business units rather than the aggregate corporate level, which has rarely been done before.

The paper is organised as follows: Section 2 characterises the Norwegian oil and gas sector and reviews Statoil's historic development. Section 3 outlines the SCBA methodology and data sources. Section 4 sets out the factual and counterfactual scenarios. Section 5 presents and discusses the results. Section 6 concludes.

2 Case background

2.1 Oil & Gas in Norway

Oil and gas, or petroleum in the wider sense[7], is the single most important industry in Norway today. In 2006, when Brent crude oil prices averaged US$65 per barrel (BP 2007, p.46), the sector contributed 25% to the country's GDP, 36% to total state revenues and 51% to total exports (NPD 2007). First commercial quantities of oil in the Norwegian part of the North Sea were found in 1969, and production started in 1971.[8,9] Production has grown substantially since, until peak output was reached in 2004 at 4.5 million barrels of oil equivalent per day (boe/d). The NCS has now entered its mature phase, but the Norwegian Petroleum Directorate (NPD) forecasts that current production levels of 4.2 million boe/d can be at least sustained until 2018, thanks to an increasing output of gas. The authorities believe that approximately 60% of the total recoverable liquids have been produced so far, but only 25% of the recoverable gas reserves (see Figure 3).

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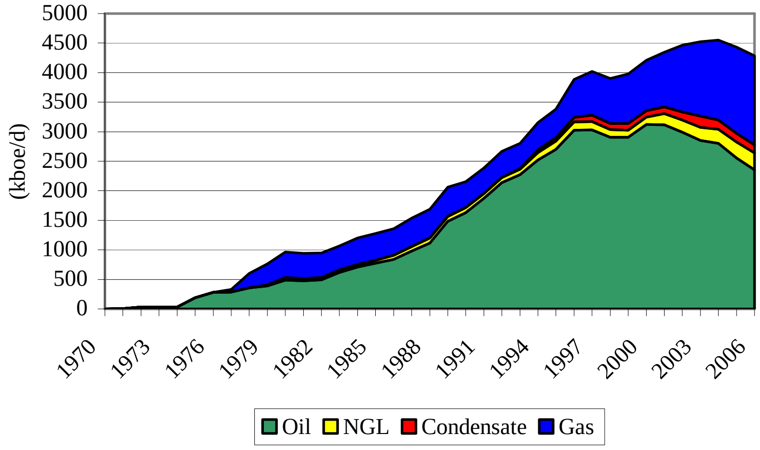
[6] Two related papers by Wolf (2008a) and Wolf and Pollitt (2008) are studies of ownership and privatisation effects in oil and gas. See also Al-Obaidan and Scully (1991) and Eller et al. (2007).

[7] The word 'petroleum' literally means 'rock oil' (from the Latin 'petra' and 'oleum'). It is sometimes used to describe liquid hydrocarbons only, but can also include natural gas and related substances. In this paper I adopt the latter and wider definition, in line with the Norwegian authorities.

[8] The offshore waters around Norway are collectively known as the Norwegian Continental Shelf (NCS): the North Sea in the South, the Norwegian Sea, and the Barents Sea in the Far North.

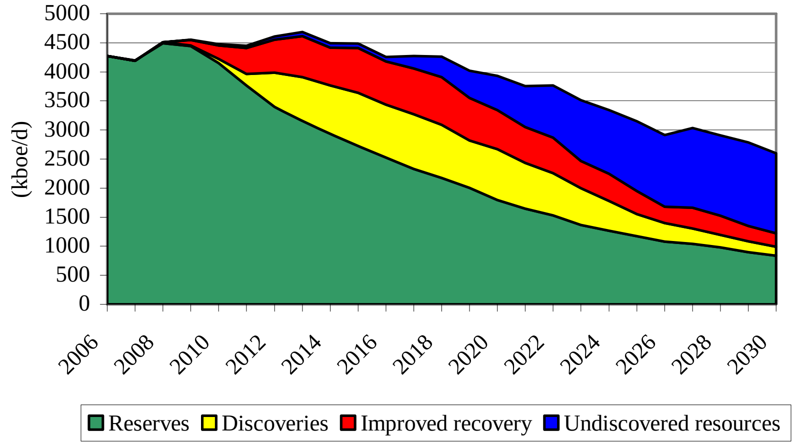
[9] Al-Kasir (2006) has a detailed overview of the history of petroleum operations on the NCS. See also Grayson (1981) and Yergin (1991), as well as the websites of the MPE and NPD.

Figure 1: Norway's historic petroleum production (1970-2006)



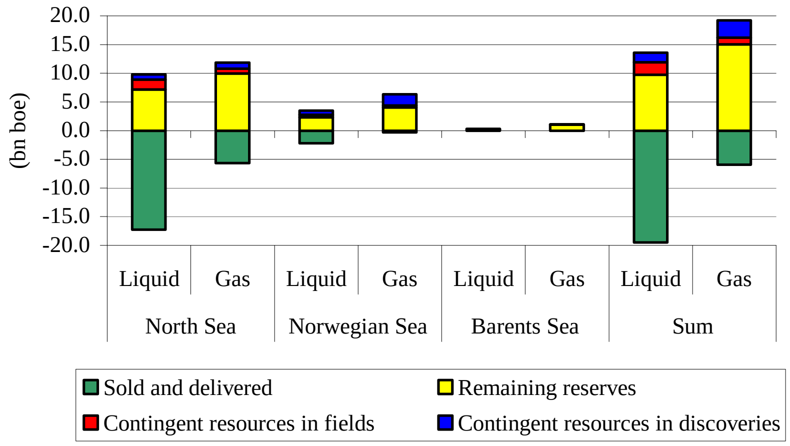
Source: NPD (2005), BP (2007)

Figure 2: Norway's forecasted petroleum production



Source: NPD (2005)

Figure 3: Norway's remaining petroleum reserves by offshore region



Source: NPD (2005)

Because of its small domestic population and its predominant use of hydropower for electricity purposes, Norway has become one of the world's key exporters of hydrocarbons, alongside Saudi Arabia and Russia. There is an extensive network of oil and natural gas pipelines on the NCS, linking most producing fields to the Norwegian shore, and/or (in the case of gas) directly to the UK and Continental Europe for export. Norway also has a number of downstream assets, including a refinery and petrochemical plants, which primarily serve the Scandinavian market, but also export to Continental Europe and the United States.

The largest players on the NCS in terms of production licences – as of year-end 2006 – are Statoil (173), Norsk Hydro (135), the Norwegian state (112) and Total (72), although in terms of petroleum reserves the direct financial interests of the state (see Section 2.2) still rank ahead of Statoil (NPD 2007).

2.2 Statoil and the "Norwegian model" of petroleum management

Norway is one of the richest countries in the world – it ranked second in 2006 based on GDP per capita (PPP) as calculated by the World Bank – thanks in no small part to its petroleum resource wealth. But even before the discovery of oil did the Norwegians enjoy a high standard of life, with a successful private industry e.g. in shipping and fishing, and in contrast to the UK on the other side of the North Sea, the Norwegian government did not need petroleum revenues to balance its budget (Grayson 1981). Having witnessed the macro-economic distortions that oil created elsewhere in the world (Auty 1993; Stevens 2003; Humphreys et al. 2007) and worrying about the industry's intrusion into the traditional way of life in coastal communities (Al-Kasim 2006), Norway decided to pursue a "go-slow" policy with regard to petroleum development (Dam 1974). It was deemed that comprehensive state control over the sector was the best way to guarantee an appropriate pace of development, and to ensure that industrial expertise was built domestically rather than abroad; state participation in strategic industries also had a long tradition in Norway, in line with social-democratic policies elsewhere in Scandinavia.

In 1971 the Storting (Norwegian parliament) passed the so-called "ten commandments" of petroleum policy, which captured a wide consensus within Norwegian society. Amongst others they called for national steering and control of all NCS operations, for the state to be an active player coordinating Norwegian interests, for the development of a successful petroleum-based industry onshore, for petroleum development to occur with due regard to existing livelihoods and the environment (including the prohibition of gas flaring), and for the creation of a national oil company to take over the state's business interests and to cooperate with other Norwegian and foreign oil companies.[10] Because the semi-private conglomerate Norsk Hydro (NH) was not considered an appropriate vehicle to implement national petroleum policy[11], a new fully state-owed company was set up in 1972 called "Den norske stats oljeselkap a.s." ("the Norwegian State Oil Company"), which was later shortened to simply "Statoil". Although some had advocated Statoil to be a holding company only for the state's direct interests in petroleum assets, the Ministry of Petroleum and Energy (MPE) was of the opinion "that only through 'learning the ropes' as an operator would the national company be able to assist the country in ensuring national control." (Al-Kasim 2006, p.48). The first assets were assigned to Statoil in May 1973, and at the end of that year the company had 54 employees, led by Managing Director Arve Johnsen (Grayson 1981).[12]

During its first decade of operations, Statoil benefited greatly from three key privileges assigned to it by the state: Statoil was granted a minimum participation of 50% in all petroleum licenses, implying a veto power on all development decisions; the company was carried through the exploration phase by the private co-investors in the respective licenses, i.e. it only had to pay its share in exploration expenses retroactively when a commercial discovery had been made; and once a discovery was declared commercial, Statoil's interest could be increased further by up to 30% (to a total of 80%) based on a sliding scale of production. In return for these privileges Statoil was not only bound by the commercial duties of the Companies Act, but also had to respond to political and social aims of government. The geo-political circumstances were very much in favour of Norway at that time: the OPEC revolution and asset nationalisations in the Middle East had made the private international oil companies desperate for access to new reserves, and a considerable part of the industry's hopes were pinned on the North Sea. The two oil price shocks in 1973 and 1979/80 further bolstered the bargaining position of the Norwegian government, but it

[10] The 'ten commandments' were formulated by the Parliamentary Industry Committee, and included in the Recommendation No. 294 (1970-71), replying to Report No. 76 (1970-71). Al-Kasim (2006, p.143) has an English translation.

[11] The state owned 51% of NH since the end of World War II, but the private shareholding was very international and the company was listed both in Oslo and in Paris.

[12] At year-end 1979 there were 710 employees in Statoil, and by the end of the 1990s this number had increases to over 18,000.

was always aware of the need for and benefits of private sector involvement on the NCS. Balancing the interests of the state with those of the international oil companies, and adjusting that balance based on external circumstances, is an ongoing priority of Norwegian petroleum policy.[13]

By the mid-1980s Statoil had grown materially, was highly profitable and continued to enjoy full state backing. But a new conservative/centre minority government sought to reduce the discretionary power of Statoil relative to the state itself.[14] In 1984 the Storting (Report No.73, 1983-84) made a number of important changes to the company's position. First, Statoil's license interests were split into two parts, the bigger part of which was transferred to the state (the "State Direct Financial Interest", SDFI). Although Statoil still managed those assets on behalf of its owner, their revenues now went directly to the public treasury. Second, the special privileges outlined earlier were withdrawn from Statoil and henceforth applied to the state instead[15] – a few years later, in a bid to become more attractive to private investors, most of these stipulations were lifted altogether. Third, Statoil could not use its existing voting interests of 50%+ to single-handedly take or veto decisions within a license group, unless such voting was authorised by the Storting on grounds of national interest. And fourth, a "Gas Negotiations Committee" ("GFU" in Norwegian) was established, comprising Statoil, NH and Saga Petroleum. Its task was the centralised export marketing of NCS gas, a task that previously had fallen exclusively to Statoil as the majority owner in all field licenses.

In 1985-86, both the oil price and the Norwegian Kroner fell sharply, and shortly thereafter Statoil faced severe cost overruns at the Mongstad refinery upgrading project, triggering the resignation of Arve Johnsen in January 1988. He was replaced by Harald Norvik, who was to remain CEO until 1999. During his time in office, Statoil continued to develop towards a (predominantly) commercially oriented

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[13] The 'Norwegian model' of petroleum management includes a number of important features other than direct state participation and national control over development. See Al-Kasim (2006, p.241-246) for a discussion of its main attributes, incl. the separation of responsibilities between Ministry, NPD and Statoil; a focus on openness and transparency in procedure, and on internal governance and HSE at each licensee; the tangible state support for not only a state-owned firm (Statoil), but also one mixed-ownership (NH) and one fully private Norwegian oil company (Saga Petroleum) on the NCS; and the Petroleum Fund to buffer the real economy from the sudden influx of petroleum revenues.

[14] The then Prime Minister Kaare Willoch later wrote in his memoirs: "The aim was to prevent Statoil from growing beyond reasonable limits and exercise disproportionate influence" (cited in Claes 2002).

[15] Statoil, like the other domestic oil companies, was still likely to receive priority allocations in future licensing rounds, but this was now at the discretion of the Ministry.

business, and the relationship with the state became increasingly arm's length. Two factors in particular supported such developments. Although Norway is not an EU member it joined the European Economic Area in 1994, which included adherence to a 1992 directive on the non-discriminatory granting of licenses for prospection, exploration and extraction of hydrocarbons.[16] State favours for Norwegian companies were therefore more difficult, and competition from foreign companies in Norway was bound to become tougher (Claes 2002). Also, Statoil and NH were increasingly looking to compete internationally, outside the NCS, and to do so they would need to be striving for more efficiency and not be seen as being politically directed. International expansion was indeed supported by the Norwegian government. As the former NPD Director of Resources states: "There is no doubt that the policy of supporting the Norwegian offshore industry (…) had added to the cost of operations. In return for this additional cost, the expertise that had been developed could bring new values to Norway based on resources outside the Norwegian Continental Shelf" (Al-Kasim 2006, p.114).

The tenure of CEO Harald Norvik ended under similar circumstances as that of his predecessor. The oil price crash in 1998 had weakened the overall profitability in the industry, and the pressures on Statoil were compounded by significant cost overruns at the giant Asgard field. In April 1999 the MPE replaced the entire board of the company, triggering the resignation of Norvik.

2.3 Privatisation of Statoil

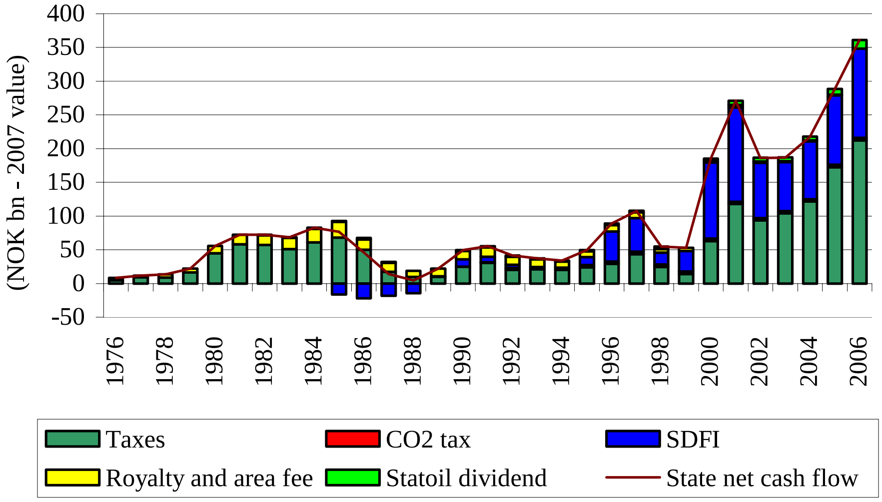
In December 1998, a few months before his resignation, Harald Norvik had for the first time publicly raised the issue of state ownership in Statoil, and called for a review in view of the heightened competition in the industry. As the public reaction was mixed, if not positive (Lismoen 1999; Noreng 2000b), the centre-right government[17] asked the new board of Statoil and its new CEO Olav Fjell to prepare recommendations for the future development of the group and the SDFI. In August 1999 Statoil management responded with an ambitious plan, in which the company was to be strengthened through the transfer of all or a significant part of the SDFI, prior to a partial privatisation and stock market listing (PIW 1999; Statoil 1999). In

[16] See Directive 94/22/EC.
[17] In office from October 1997 to March 2000, led by Prime Minister Kjell Magne Bondevik.

July 1999 the MPE also appointed its own financial and legal advisors on the available restructuring options (MPE 1999)[18], and planned to submit a White Paper to parliament in the spring of 2000.

The possible privatisation of Statoil and SDFI restructuring were considered together, because the Norwegian state at the time derived its petroleum revenues through four different channels: the SDFI (accounting for more than 40% of total NCS reserves), tax revenues from all non-SDFI participants on the NCS, its 100% ownership of Statoil, and a 44% ownership of NH.[19] Statoil argued that receiving a substantial part of the SDFI prior to privatisation would strengthen the firm's competitive position and hence valuation levels. Statoil also wanted to be in a position to swap NCS licenses versus international assets. Because Statoil operated the SDFI on behalf of the state, any efficiency gains at the company would have a double positive impact on sovereign value creation. On the other hand, any efficiency-enhancing restructuring of the SDFI outside of Statoil (i.e. through sale or exchange of license interests with other NCS participants) could also reduce operating costs, increase taxation, and attract additional investment to the country.

Figure 4: State revenues from petroleum resources



Source: (NPD 2007)

[18] Although at that point partial privatisation was certainly not an official policy of the government, the appointment of an investment bank as adviser on restructuring options is an interesting choice.
[19] In 1999 the state was diluted from 51% when NH acquired private Norwegian firm Saga Petroleum. Statoil, which had owned 20% of Saga, also received some of the assets in a three-way deal.

The Bondevik government fell in March 2000, and although the incoming Labour Prime Minister Jens Stoltenberg supported Statoil's partial privatisation, his party and the labour unions took some additional months to be convinced (Lismoen 2000; Noreng 2000a; PIW 2000). In December 2000 the government's plans were presented to parliament (MPE 2000), which approved them – with some small modifications – on 26 April 2001. The key elements of the privatisation and restructuring were (Statoil 2001):

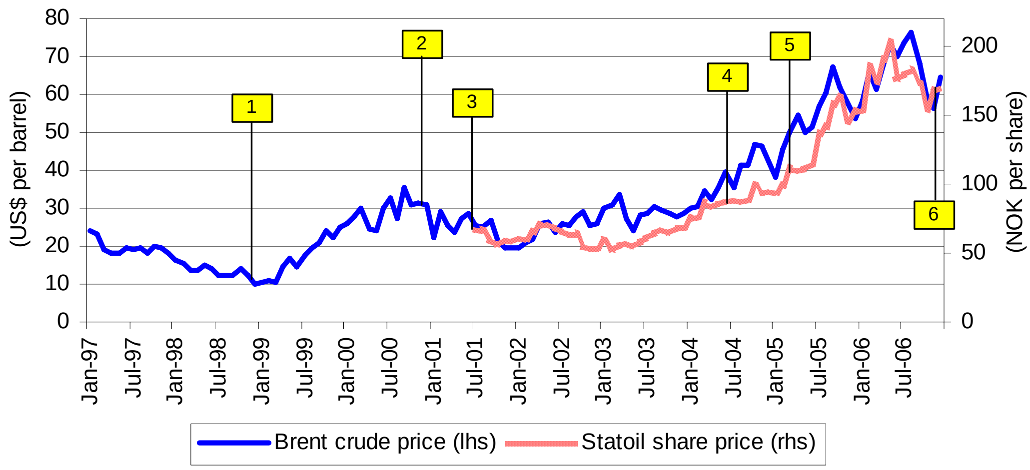
- *Sale of 15% of SDFI assets to Statoil* (paid for in cash, infrastructure assets and subordinated debt). As a result Statoil's net proven reserves on the NCS increased by 54% to 3,787 million barrels of oil equivalent, and NCS production increased by 60% to 936 kboe/d.
- *Partial privatisation of Statoil.* Including the exercised over-allotment option of shares, 19.2% of Statoil was sold and listed on the Oslo and New York Stock Exchanges in June 2001, valuing the company at approximately US$16.4 billion. Almost exactly half of the shares being offered were primary shares issues by the company, with the other half being secondary shares sold by the government. But because the new cash raised by Statoil was used immediately to repay outstanding debts to the MPE (arising from the SDFI sale), the Norwegian state was effectively the sole recipient of funds.
- *Establishment of a state-owned company (Petoro)* to take over the administration of the remaining SDFI assets from Statoil. Under a special instruction, Statoil nevertheless continues to *market* the SDFI output on behalf of the state.
- *Establishment of a state-owned gas infrastructure company (Gassco)* to take over operatorship of some NCS gas pipelines previously operated by Statoil.[20]
- *Sale of 6.5% of SDFI assets to third parties.* Executed in March 2002, SDFI assets were auctioned to NH and others to improve license allocations, strengthen competition and investment incentives.

The 15% share of SDFI assets sold to Statoil was clearly less than the company had hoped for, but parliament allowed a further reduction in state ownership down to 67% in order to accommodate possible strategic alliances or share-based acquisitions.

[20] This was done to prevent conflicts of interest between a part-private Statoil and other NCS operators.

When no such transaction was forthcoming in the three years following the IPO, the Norwegian government took advantage of the favourable oil price environment. In July 2004 and February 2005 it sold two further instalments of Statoil shares (approximately 5.4% each, using accelerated bookbuild, i.e. single-day transactions without any prior notice to the markets), reducing the level of state ownership to 70.1% as of year-end 2005.

Figure 5: Key privatisation steps for Statoil



Notes: (1) Statoil CEO asks for ownership review; (2) Draft legislation introduced to Storting; (3) Statoil IPO; (4) 2nd Statoil share offering; (5) 3rd Statoil share offering; (6) Proposal for Statoil/NH merger

2.4 The Statoil-Hydro merger

Because Statoil had been allocated a much smaller part of the SDFI assets than the company had envisaged, shortly after the IPO speculation started as to whether Statoil would be interested in acquiring NH's petroleum assets (PIW 2002). A first opportunity presented itself after another change of CEO at Statoil. Olav Fjell had to resign in September 2003 over kickbacks paid by Statoil to Iranian politicians and businessmen. CFO Inge Hansen became interim leader and held exploratory talks, which were discontinued and made public in February 2004 (Statoil 2004). A permanent replacement, Helge Lund, took over as CEO from August 2004. Since then, ongoing global industry trends towards consolidation and technically increasingly complex and investment-heavy upstream projects, and the growing international importance of state-controlled petroleum companies from Russia, China and India seemed to strengthened the case for some form of cooperation.

In December 2006 the merger of Statoil with NH's petroleum division was announced. The transaction was approved by the EU and the Norwegian parliament over the summer, and officially completed on 1 October 2007. For each NH share Statoil issued 0.8622 shares in the new company "StatoilHydro". Old Statoil shareholders hold 67.3% of the combined company. State ownership was diluted to 62.5%, but the government expressed its clear intention to remain a long-term shareholder in StatoilHydro, and to rebuild its stake to over time to more than 67% (Norsk Hydro and Statoil 2007).

The ultimate outcome of just one surviving Norwegian oil company is not a complete surprise given the industrial dynamics of the petroleum sector. In fact, as early as 1971 the government had written in a report to the Storting: "In the opinion of the Ministry the character of the petroleum industry is such, involving heavy risks and heavy investments, that it is barely possible for more than one, or at the most two Norwegian groups to go to the full extent towards becoming an oil company on an international scale" (Al-Kasim 2006, p.56). Contrary to the Statoil part-privatisation, however, the Statoil-Hydro merger attracted a fair share of domestic criticism, largely due to the further increase in concentration on the NCS and the potential loss of competitive pressures and incentives (Osmundsen 2007).

3 Methodology and data

3.1 Social cost-benefit analysis

The SCBA methodology for privatisations[21] aims to carefully identify the overall welfare changes from divestiture – and from possibly related restructuring – as well as the distribution of changes amongst the principal stakeholders. As Newbery and Pollitt (1997, p.278) put it: "[W]ho gained, who lost, by how much, and at what social value"? SCBA answers these questions by comparing the historical and predicted future evolution of the privatised firm with a counterfactual scenario of continued full government ownership. The methodology was first set out by Jones et al. (1990), and

[21] Jones et al. prefer to speak of "divestiture" to emphasize the transfer of ownership, rather than market liberalisation or other concepts often associated with privatisation.

then applied in Galal et al. (1994) to 12 case studies – mostly from infrastructure, airlines/logistics and telecoms sectors – in four developed and middle-income countries. They find that divestiture substantially improved economic welfare in 11 of the 12 cases, with the main drivers being an increase in investment, improved productivity, more rational pricing policies, increased competition and effective regulation. Using the same methodological approach, Jones et al. (1998) confirm the positive welfare effect in a study of privatisations in Cote D'Ivoire. Several SCBAs exist on the UK electricity sector, including Newbery and Pollitt (1997) – who find positive welfare implications from the privatisation of the Central Electricity Generating Board, but a skewed distribution of benefits in favour of producers – Green and McDaniel (1998) and Domah and Pollitt (2001). Rail privatisation in the UK and Canada is examined in Pollitt and Smith (2002) and Boardman et al. (2007), respectively, with both sets of authors finding positive welfare implications from privatisation.

Following Jones et al. (1990) the overall change in welfare can be written as:

$$\Delta W = V_{SP} - V_{SG} + (\lambda_G - \lambda_P)Z \qquad (1)$$

where ΔW is the total change in social welfare, V_{SP} is the social value under private operation, V_{SG} is the social value under continued government operation, Z is the sale price, and λ_G and λ_P are shadow multipliers on government and private funds. Unless these shadow multipliers differ, the sale price is a straightforward transfer of funds from private investors to government with no implications for aggregate welfare. For the initial assessment we thus assume no difference between these multipliers – this issue will be revisited later – and focus on the first two terms of equation (1). Under the same assumption the distributional impact can be simplified to:

$$\Delta W = \Delta Cons + \Delta Prod + \Delta Gov \qquad (2)$$

where $\Delta Cons$ is the change in consumer welfare, $\Delta Prod$ is the change in producer welfare (equivalent to shareholder benefits), and ΔGov is the change in government welfare.[22] Privatisation offers substantial opportunities for private industry buyers or private shareholders, but a key concern is whether such gains come at the expense of

[22] Equation (2) further abstracts from potential welfare changes on employees and competitors, and from changing externalities. Each of these assumptions will be discussed in due course.

other groups, resulting in aggregate welfare losses. Jones et al. (1990) call this the "fundamental trade-off of divestiture" – privatisation might provide improvements in managerial incentives and technical efficiency, but might also lead to allocative inefficiencies and the misuse of market power. Also, the sales price received by the government might not adequately reflect intrinsic asset values.

Fortunately, the first set of issues does not arise under competitive market conditions, in which case the impact on consumer surplus and welfare can be assumed to be zero (Newbery and Pollitt 1997; Boardman et al. 2007).[23] Although it has a dominant producing position on the NCS, all of Statoil's sales markets have long been competitive: its crude oil production is exported onto the world market, its refined oil products and petrochemicals compete for market share in Scandinavia, the Baltics and North-West Europe against several established downstream players. Natural gas supply into Europe was for a long time characterised by oversupply, with Norwegian producers struggling to conclude long-term sales contracts that merited the development of dry gas or even associated gas fields on the NCS (Al-Kasim 2006). Since the mid-1990s demand for natural gas steeply increased and producers certainly enjoyed a much better bargaining position. But – other than for considerations of portfolio diversification and energy security in the purchasing countries – Norwegian gas still competes on price against pipeline supplies from the UK, Russia and Algeria, and increasingly against LNG deliveries from elsewhere. It should also be noted that – after Norway abolished the GFU under pressure from the EU – Statoil-operated gas fields on the NCS compete against fields of other operators, and that even as an operator Statoil is accountable to its peer shareholders in individual field, and has to justify its pricing position in gas contract negotiations. Further to these considerations, there has been no suggestion or empirical evidence yet of changes in Statoil's pricing or output behaviour post privatisation. In summary, it is therefore reasonable to assume that Statoil's pricing and output policies following privatisation did not differ from counterfactual scenarios without privatisation, and that thus $\Delta Cons$ is zero.[24]

[23] When prices do not change, Newbery and Pollitt (1997) point out that improvements in technical efficiency, i.e. falling costs, are a necessary but not sufficient condition for social welfare to increase.
[24] Even if allocative inefficiencies existed and were included in the overall welfare consideration, their impact would likely be very small. Newbery and Pollitt (1997, p.280) measure such effects by the deadweight loss, $0.5\varepsilon\varphi^2$ as a proportion of expenditure, where ε is the elasticity of demand and φ is the proportional difference between the factual and counterfactual price. A simple alternative estimation is the so-called "Slutsky compensation" (Varian 1984; Galal et al. 1994), which calculates allocative

Given that prices and outputs are the same in the factual and counterfactual scenarios, the change in costs is the same as the change in profits, and based on Boardman et al. (2007) the change in welfare can be written:

$$\Delta W = V_{SP} - V_{SG} = \Pi_P - \Pi_G - TC \tag{3}$$

where Π_P is the present discounted value of profits under privatised ownership, Π_G is the corresponding value under the counterfactual scenario of continued government ownership, and TC is the present value of all transaction costs of privatisation. 'Profits' in this context means public rather than private profits (Jones et al. 1990; Galal et al. 1994). At this point a short clarification of the terminology is helpful. Jones et al. refer to the net income (or earnings after tax) from the corporate income statement as private profit. They contrast this with public profit, which differs in several ways, most notably the treatment of non-cash items such as depreciation, interest expenses, and the treatment of taxes, which are not lost for public profits because they accrue to the state. In practical terms, this public profit is very close to the pre-tax value of the enterprise cash flow used in conventional DCF valuation models (Brealey and Myers 1996; Koller et al. 2005). Because in the following we frequently need to differentiate between pre-tax and post-tax values, the term 'public profit' shall be continued to be used in the sense of Jones et al, i.e. as a pre-tax cash flow value, and 'private profit' (or 'after-tax' or 'shareholders' profit) shall be defined as the portion of that public profit accruing to private investors.

$$\Pi \equiv \Pi^{Pub} = \Pi^{Priv} + T = (1-\tau)\Pi^{Pub} + \tau\Pi^{Pub} \tag{4}$$

where Π or Π^{Pub} is the present value of public profits, Π^{Priv} is the present value of private (post-tax) profits, T is the present value of corporate tax payments, and τ is the effective corporate tax rate. Jones et al. point out a few additional differences between net income and public profit, which are largely due to variations between accounting and economics, but these are of interest for the absolute level of valuation only. When comparing post-privatisation and counterfactual scenarios, which is the principal aim

efficiency changes as the previous period's quantity times price change, neglecting the effect of demand elasticity.

of SCBA, the difference principle ensures that virtually all of them cancel out and do not require further attention.[25]

Although the notation is based on profits rather than costs, it should be re-emphasised that both are perfectly equivalent approaches, as the analysis assumes no differences in petroleum prices or revenues between the factual and counterfactual scenarios. The profit notation is chosen because it better reflects our valuation approach (using a full-scale company model rather than a discounted cost stream) and because it provides public and private values for Statoil that can be directly compared to the actual sales price received in the IPO.

The distribution of welfare gains (or losses) is important because the ultimate judgement on success or failure of privatisation often rests on it. Only Pareto improving privatisations, where none of the major stakeholders lose out, are likely to receive public support and approval. In Statoil's case, with consumer surplus unaffected due to the competitiveness of the company's product markets, we can focus on the distribution of welfare changes between the company with its new private shareholders on the one side, and the tax-funded state on the other. Looking at the changes in government welfare first, the state foregoes the company's future public profits generated under the counterfactual scenario, and in return receives the sales price, plus the present value of all taxes and any residual share in the private profits, both generated under private part-ownership. If the privatisation is underpriced, the state recovers some of the Norwegian shareholders' benefits through capital gains tax, but the state in any case also bears the full transaction costs of the sale. Formally, with λ being the share of equity sold through partial privatisation, Z and U being the sales price and amount of underpricing for 100% of the firm, respectively, and θ being the effective rate of capital gains tax, we can write:

$$\Delta Gov = \underbrace{\lambda(Z+\theta U)}_{\text{Sales price and tax on underpricing}} - \underbrace{\Pi_G}_{\text{Public profits (counterfactual)}} + \underbrace{\tau\Pi_P + (1-\lambda)(1-\tau)\Pi_P}_{\text{Taxation and share of private profits (factual)}} - TC \qquad (5)$$

which, when the firm is fully divested, simplifies to (see Boardman et al. 2007, p.13):

$$\Delta Gov = Z + \theta U - \Pi_G + \tau\Pi_P - TC \qquad (6)$$

[25] The benefits of the difference principle are quite substantial: *any* underlying measurement or valuation errors cancel out as long as they have been committed consistently across the scenarios.

The change in welfare to private investors then simply follows as the residual:

$$\Delta Prod \approx \Delta W - \Delta Gov \text{ [26]} \tag{7}$$

3.2 Data

Most of the data on operational and financial performance comes from official company reports and disclosures. Annual reports for both Statoil and NH (the primary benchmark for upstream performance) were collected for the years 1996 to 2006. Particularly useful is the standardised disclosure on oil and gas producing activities (SFAS No. 69), which is mandated by the U.S. SEC and which is available for both firms for the years 1998 onwards.[27] Additional information comes from the Statoil IPO prospectus, dated June 2001, and the same is true for the Statoil/Hydro Petroleum merger prospectus, dated May 2007. To further track the developments in corporate performance from Statoil's own perspective – including the delivery on and changes to self-imposed performance targets such as operational cost savings, investment cost savings, return on capital, and physical output growth – all of Statoil's investor presentations and press communications have been collected and analysed, particularly those from the annual Capital Market Days since 2001. The second benchmark for upstream performance used in the following is a synthetic aggregate of OECD-based oil companies called "Global OilCo", which is regularly compiled and updated by UBS Investment Research; several of these reports, dated 2000 to 2007, have been available as sources.

Importantly, the oil and gas research team at UBS Investment Research has also shared its insights on Statoil's revenue and cost structures in the form of a corporate financial model, dated June 2006. This model, which has been modified, extended and updated by the author, formed the basis for some of the forecasts and sensitivity analysis presented later in this paper. It should be emphasised that, due to the difference principle of the SCBA, the results of this analysis are not dependent on any external valuation assumption or forecast level. The UBS model proved very useful,

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[26] In the simplified case of full privatisation, no underpricing and no transaction costs the new shareholders get the after-tax profits and pay the sales price:

$$\Delta W = \Delta Gov + \Delta Prod = Z - \Pi_G + \tau\Pi_P + (1-\tau)\Pi_P - Z = \Pi_P - \Pi_G$$

[27] Boynton at al. (1999) show that these disclosures are useful indicators for efficiency.

however, in estimating Statoil's divisional cost structures (e.g. in refining or natural gas transportation) in greater detail than what is disclosed in the annual accounts.

The author has also conducted informal interviews with a former member of the Norwegian state administration, a former board member of Statoil, and an external adviser to the MPE, all of which were closely involved in Statoil's privatisation process. These conversations served to inform, challenge or confirm many of our principal observations and assumptions.[28]

Finally, in order to discount future monetary streams into present values, the annual CPI and GDP deflator indices for Norway were collected from the IMF's International Financial Statistics.

4 Factual and counterfactual

In this section we will briefly present some general considerations in constructing the privatisation scenarios, and then detail both the factual and counterfactual. For ease of presentation we will limit ourselves to two counterfactual cases, with supporting sensitivity analysis to follow. Throughout, we follow Galal et al. (1994) in being deliberately conservative in ascribing certain changes to the cause of privatisation.

Boundaries of analysis

For Statoil detailed accounts in accordance with U.S. GAAP (and including SFAS 69 disclosure) are available from 1998 onwards, which is therefore used as the initial year of analysis; the factual scenario uses historic figures until 2006, with an explicit forecast period 2007-2010 and a terminal value calculation thereafter.

Another reason to include historic numbers only until 2006 is that the focus of analysis is on Statoil's 2001 privatisation rather than the merger with Hydro Petroleum. All factual and counterfactual forecasts (post 2006) consequently are for the 'old' pre-merger Statoil. Furthermore, we do not specifically consider the impact of the smaller follow-on offerings of Statoil shares in 2004 and 2005. Because Statoil at that time was a liquidly traded stock, these offerings are assumed to have been executed at fair market value. Unless they significantly impacted managerial

[28] Between 2002 and 2004 the lead author of this paper has, in a different professional capacity, worked on a regular basis with the MPE, and on an occasional basis with Statoil.

incentives and technical efficiency in the short period up to 2006, or unless the shadow welfare weights of government and the private sector differ substantially, these follow-on sales are straight transfers of funds without implications for social welfare.

An important decision is the choice of pre- and post-privatisation period. Based on the chronology of events described earlier, the key decisions in favour of privatisation were taken in the year 2000, although privatisation had first surfaced as an option in 1999; these years could therefore have been treated as intermediate years. But because Statoil's performance during that period is likely to have benefited from cost-cutting measures implemented in 1998/99 – which are independent of privatisation – and to be conservative in ascribing benefits to privatisation, the period up to and including the full year 2000 is considered part of the pre-privatisation phase. Only changes from January 2001 onwards (which is also the base date for all present value calculation) count towards the costs and benefits of privatisation.[29]

In terms of coverage, this SCBA of Statoil's IPO does not consider the impact on the efficiency and welfare of direct competitors or suppliers such as oil service contractors. In the latter case one might argue that a part-privatised Statoil is likely to have abolished any favouritism towards domestic suppliers, thus reducing Norwegian rents and welfare at the benefit of international competitors. Any such effect, however, is likely to be offset by the increased competitive pressures on the NCS, which will increase efficiency at Statoil's direct competitors and thus improve Norway's welfare as the tax-collecting host of these firms. Furthermore, the sale of 6.5% of SDFI assets to oil companies other than Statoil – which provided an opportunity to streamline ownership interests, strengthen incentives and improve operational cost structures – was a direct consequence of Statoil's part-privatisation. These benefits accrued to Statoil's competitors (and the Norwegian state through taxation), but are not explicitly included in this analysis and provide further upside to our estimate of privatisation benefits.

A key issue in evaluating the costs and benefits of Statoil's privatisation is the company's dominant operatorship position of upstream NCS assets. To diversify

[29] Wolf and Pollitt (2008) show that in oil privatisations the majority of performance improvements occur in the three years prior to the effective change in ownership. Excluding all improvements up to six months before the IPO from the benefits of privatisation therefore will underestimate the anticipation effect of privatisation.

operational risk and financing requirements, virtually all large E&P projects in the oil industry are jointly owned by several shareholders, creating a situation where direct industry competitors are cooperating on a regular basis at the project level. Only one of the shareholding oil companies – often the one with the largest equity interest, but not necessarily so – acts as the technical operator of the field, but its decisions and level of efficiency impact on the economic profits of all parties involved.[30] In the case of Statoil, the company in 2006 had equity interests in 36 producing NCS fields and operated 24 of these. The self-operated fields accounted for 88% of its total oil and gas production, but on average its equity shareholding in these same fields was only 33.1%. Other shareholders were the Norwegian state (SDFI) with 32.4%, NH with 9.4%, and other international oil companies with 25.1% (all 2006 production-weighted averages, calculated from Statoil (2007) and NPD (2007)). Overall, Statoil-operated fields accounted for circa 60% of Norwegian production in 2006. Potential efficiency improvements at Statoil therefore spill over to all other project shareholders (including the Norwegian state through SDFI and NH) as well their tax payments.

Forecast period and terminal value calculations

As set out before, the analysis is based on a detailed valuation model for the years 1998 to 2010, and a terminal value calculation thereafter. The factual comprises historic accounts until 2006, followed by an explicit forecast period for 2007 to 2010. The counterfactual scenarios differ from the factual from the year 2001 onwards. For the terminal value, the basic methodology is a simple perpetuity calculation, although this is cross-checked against two alternative methodologies, namely exit multiple calculation and a target return on newly invested capital. In the simplest case, there is no assumed real term business growth (but also no decline)[31] in the period post 2010, but sensitivity checks on this assumption will be presented.

Discount rates

The calculations of present values as of 01 January 2001 use mid-year discounting of annual public profits. All numbers are used in nominal terms, and the applicable discount rates are therefore also nominal. For the two main counterfactual scenarios

[30] In practice it is therefore wrong to think of the other shareholders as passive investors only. The have several options for influencing and making decisions, from informal conversations to formal votes at shareholder meetings, and the operator is obviously accountable to them.
[31] Assumed inflation in the terminal value period is 2.5%, offset by nominal discount rates (see below).

set out in this paper we use flat nominal discount rates of 6% and 8%, respectively. They are chosen to bracket a range of other possible discount rates, including annually variable discount rates based on inflation data (CPI or GDP deflators)[32] and assumed real discount rates. Moore et al. (2003) argue for a real social discount rate of 3.5%, but other suggestions exist, including the use of sovereign bond or corporate bond benchmark rates (see Boardman et al. 2006).

4.1 What happened: the factual

Table 1 summarises some of the key financial (accounting) and operating metrics of Statoil over the period 1998 to 2006. Operationally, the company has clearly grown in terms of oil and gas production and in terms of employees.[33] The improvement in financial performance is spectacular, although it is difficult at this point to separate the impact of commodity prices from true technical efficiency gains. Most individual items can be seen to develop in line with strategic guidance given at the time of the IPO, but also to reflect the earlier 1998/99 group-wide improvement programme: a focus on capital discipline (additions to property, plant and equipment have remained well below the 1999 level until 2003), portfolio restructuring and streamlining (aggregate disposals in 1999-2006 amount to 20% of total assets at the IPO in 2001), continued growth in Norwegian E&P (mainly through accelerated production and improved recovery), and significant investment in core international E&P projects.

Supporting evidence that Statoil indeed managed to improve its internal efficiency and performance, and not just relied on the supporting current of commodity prices, comes from the development of its traded share price relative to industry peers, which were exposed to these same macroeconomic conditions. As shown in Table 2, Statoil's shares have significantly outperformed other major European/OECD oil companies such as Eni, Total or BP, and also outperformed a global index of oil and gas producers (particularly if this index is calculated in terms of Norwegian currency and thus comparable to Statoil's share).[34]

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[32] To estimate corporate cost inflation, GDP deflators are often the preferred choice, but in this case the national deflator has been pushed up by the rise in commodity prices since 2000, which are Statoil's output rather than input. The GDP deflator will therefore overestimate Statoil's cost increases.

[33] Employment numbers drop by a significant 15% between 1998 and 2000, as asset disposals and cost reductions take place, but rise sharply post 2000 as the business expends; in 2006 employment is 31% above 1998 levels and 55% above 2000 levels.

[34] The individual stocks are measured in their respective home currencies.

Table 1: Key accounting and operating data for Statoil (1998-2006)

(NOK m, except where stated otherwise)	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Revenues	114,648	150,132	230,425	236,961	243,814	249,375	301,443	387,411	425,166
Total operating profit	10,288	17,578	59,991	56,154	43,102	48,916	65,085	95,043	116,881
- E&P NCS	*67%*	*96%*	*78%*	*75%*	*79%*	*77%*	*78%*	*78%*	*76%*
- E&P International	*-25%*	*-11%*	*1%*	*2%*	*3%*	*3%*	*6%*	*9%*	*9%*
- Natural Gas	*49%*	*29%*	*13%*	*14%*	*15%*	*13%*	*10%*	*6%*	*9%*
- Manufacturing and Marketing	*9%*	*-10%*	*8%*	*8%*	*4%*	*7%*	*6%*	*8%*	*6%*
- Other	*0%*	*-3%*	*0%*	*0%*	*0%*	*-1%*	*-1%*	*-1%*	*0%*
Corporate tax	6,809	12,856	40,456	38,486	34,336	27,447	45,419	60,036	80,360
Net income	1,640	6,409	16,153	17,245	16,846	16,554	24,916	30,730	40,615
Acquisitions	-	-	-	-	-	-	-	13,154	-
Disposals	1,472	6,636	6,000	5,115	3,298	6,890	3,239	8,855	2,010
Additions to PP&E	24,360	27,772	17,292	16,649	17,907	22,075	31,800	31,389	39,486
Total assets		213,169	213,649	199,695	205,430	221,600	248,243	288,979	315,468
Shareholders Equity		56,105	67,826	51,774	57,017	70,174	85,030	106,644	122,228
E&P production (kboe/d)	937	965	986	1,008	1,073	1,071	1,106	1,169	1,136
- NCS (kboe/d)	*854*	*878*	*919*	*943*	*986*	*982*	*991*	*985*	*958*
- International (kboe/d)	*82*	*87*	*67*	*65*	*87*	*88*	*115*	*184*	*178*
Employees (#)	19,399	17,184	16,408	16,686	17,115	19,326	23,899	25,644	25,435

Source: Statoil Annual Reports and Accounts, Statoil IPO prospectus

Notes:

Saga transaction in 1999 not reflected as acquisition, because shares treated as tradeable securities in the accounts.

SDFI asset acquisition in 2001 treated as transaction between entities under common control, thus included as if always part of Statoil.

Table 2: Share price performance of Statoil and industry peers (since June 2001)

June 2001 to …	Statoil	Eni	Repsol	Total	BP	RD/Shell	FT World O&G Prod. (in US$)	FT World O&G Prod. (in NOK)
Y/E 2001	-11%	-9%	-23%	-8%	-15%	-21%	-13%	-15%
Y/E 2002	-15%	-2%	-40%	-22%	-32%	-42%	-20%	-40%
Y/E 2003	8%	-3%	-27%	-16%	-28%	-42%	-1%	-28%
Y/E 2004	37%	19%	-9%	-8%	-20%	-42%	22%	-19%
Y/E 2005	123%	57%	18%	22%	-2%	-28%	60%	17%
Y/E 2006	139%	69%	24%	27%	-10%	-26%	89%	27%

Source: Datastream

Including the partial exercise of the over-allotment option, a total of 394,417,002 shares were sold in the IPO, 52.2% of which were existing shares sold by the government, with the remainder being new shares issued by the company. The basic sale price was NOK 69.0 per share, but there were discounts in place for Norwegian retail investors and employees.[35] Because 6% of shares were eventually allocated to these two groups (78% went to international institutional investors, and 16% to Norwegian institutions), the selling parties forewent approximately NOK 85.8 million in price discounts out of a nominal sales revenue of NOK 27.2 billion (0.32%).[36] As Norwegian tax residents are subject to capital gains tax at 28%, part of the discount is reclaimed by the state at the time of the disposition of shares. In addition to the discount, one year after the IPO Statoil issued a total of 1,558,026 treasury shares under the bonus plan (implying that at least 66% of the retail shares were held for at least one year), which at the IPO price are valued at NOK 107.5 million. Beyond these discounts and bonus shares there was no underpricing of Statoil's shares in the conventional sense (Welsh 1989; Jones et al. 1999; Megginson et al. 2000): the closing price at the end of the first day of trading was NOK 69.0, identical to the issue price.

[35] Norwegian retail investors received a discount of NOK 3.0 per share on purchases up to an aggregate purchase amount of NOK 25,000, or, for Statoil employees, up to an aggregate purchase amount of NOK 75,000. Statoil employees received a further discount of up to 20% of the purchase price, limited to a total additional discount of NOK 1,500 per employee. Finally, domestic retail buyers, including Statoil employees, were entitled to one free bonus share for every 10 shares purchased (subject to the same ceiling amounts as before) and held for one year after the IPO.

[36] The total discount calculation is based on the following information/assumptions: 62,000 Norwegian retail investors were allocated shares, an average of 382 shares, which – at the discounted retail price of NOK 66 per share – gives an average retail investment of almost exactly NOK 25,000. It is also known that 60% of the then Statoil workforce participated in the offer. We assume that these employees bought the same number of shares as the average Norwegian retail investor and thus received the full additional discount of NOK 1,500 per employee.

The transaction costs of privatisation are detailed in the IPO prospectus. Listing expenses (which include marketing and printing expenses, legal fees etc.) were NOK 352.9 million, and underwriting commissions to the investment banks were NOK 356.9 million.[37] The underwriters and the state also agreed a discretionary incentive payment of up to 0.25% of the aggregate offer value. Assuming that this incentive payment has been made, the total transaction costs are NOK 732.6 million.

4.2 What would have happened: the counterfactual

Because Statoil would have operated in competitive markets anyway, its pricing and output policy (in the sense of deliberate output reductions to reap monopoly profits) is unchanged in the counterfactual scenario of continued full state ownership. In terms of output capacity (i.e. the technical ability to accelerate production from known reservoirs or to improve overall productive potential) we will also take the factual output generation as given, and instead solve for the counterfactual costs to support this given profile. The focus of analysis is therefore on costs – including operating costs, overhead costs and investment costs – and their translation into public profit and welfare generation.

To estimate a range of plausible welfare changes, two main counterfactual scenarios, Scenario A and Scenario B, will be developed in the following. Exploration and production of hydrocarbons is the most important activity within Statoil, and the credibility of the counterfactual scenarios benefits greatly from the fact that (a) a truly comparable competitor exists in the form of NH, which is subject to virtually the same external environment as Statoil; and (b) all E&P costs and results are recorded in detail and in a standardised way within the annual SFAS 69 disclosure. For costs outside the E&P segments, the counterfactual scenarios rely on more general assumptions and extrapolations, based in part on the upstream results.

[37] Page 187 of the IPO prospectus gives both a detailed breakdown of the various components of underwriting fees, and an aggregate cost per-share based on simplified assumptions. NOK 356.9 million is the cost estimate based on the detailed disclosure, only slightly different from the estimate based on the aggregate information (NOK 352.9 million).

Table 3: Changes in counterfactual scenarios (2001-06) relative to factual

	CF Scenario A	CF Scenario B
Operating costs		
E&P NCS	Benchmark: NH (NCS) Base period: 2000	Benchmark: GOC Base period: 2000
E&P Int'l	---	---
Natural Gas	---	5% higher costs
M&M	---	5% higher costs
Overhead costs	---	---
Investment costs		
E&P NCS	Benchmark: NH (NCS) No historic cost differential	Benchmark: GOC No historic cost differential
Other	---	---
Externalities (HSE)	---	---
Operatorship effects (E&P NCS)	Included (66.9% of projects)	Included (66.9% of projects)

Operating cost

In turn, we will examine operating costs (on a per-barrel basis) for all four major business divisions, i.e. NCS E&P, International E&P, Natural Gas, and Manufacturing and Marketing (M&M).

For the two E&P divisions, operating costs (also called production costs or lifting costs) are part of the total technical costs[38] and include the costs to bring oil and gas from the reservoir to the surface, including the maintenance of wells and related facilities, after hydrocarbons have been found, acquired, and developed for production. To derive counterfactual upstream production costs per barrel, two benchmarks are used. The first benchmark is the petroleum business of NH, which is somewhat smaller than Statoil but structurally very comparable.[39] In fact, because of the long-standing domestic policy of balancing state and private Norwegian interests in NCS licence allocations, the two companies often participate in the very same assets: at the time of Statoil's IPO in 2001, Statoil had an equity interest in *all* of the 15 producing fields that contributed to NH's total equity production, and NH in turn –

[38] Other than production costs, technical costs also include exploration and depreciation (DD&A) charges. The latter two are non-cash expenses, and will be analysed in their related form of finding and development costs, a cash-based measure of upstream investment efficiency. For Statoil, production costs have – in the period 1998 to 2006 – accounted for between 30% and 40% of total technical costs.
[39] Until 2004 NH was a conglomerate, but managed its businesses reasonably independent of each other and provided detailed accounts for its oil and gas business. NH spun off its agri-fertiliser activities as a separate company in 2004, and sold the petroleum activities to Statoil in 2007; it currently focuses on aluminium and renewable energy.

through these 15 fields – had a shared interest in 71% of Statoil's output.[40] In these fields with joint ownership usually one of Statoil or NH acts as operator with a larger equity interest and the other is a minority shareholder only, so that Statoil still operated 74% of its total equity production and NH operated 68% of its own output. But it is clear that some degree of operational overlap exists and that therefore the accounts tend to underestimate efficiency differences between the firms: they both benefit from improvements at the other company and are punished for its mismanagement. The second benchmark used for the upstream activities of Statoil therefore is chosen to avoid this type of overlap: the Global OilCo (GOC) is a synthetic aggregate of the largest OECD oil companies, calculated and published by UBS Investment Research. Based on the standardised SFAS 69 disclosures of the constituent parts, the GOC provides a comprehensive picture of the global oil sector cost performance over the same period. The main drawback of GOC versus NH is that it does not reflect the specific circumstances of the NCS – it is broader, but by definition less specific.

Figure 6: Factual production (lifting) costs per boe – NCS assets

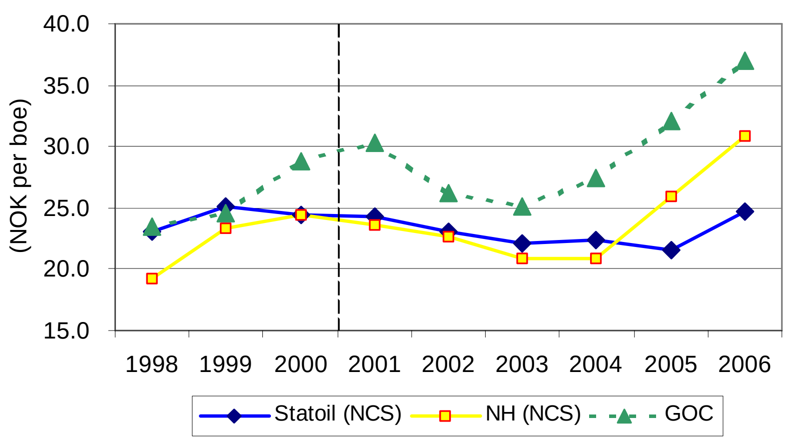


Figure 6 shows the factual per-barrel production costs for Statoil, Norsk Hydro (both for their NCS operations only) and GOC. In the pre-privatisation period 1998-2000, Statoil's cost were on average 9.1% higher than NH and 5.0% lower than GOC. Boardman at al. (2007, p.8) apply these historic cost differentials to derive counterfactual costs for the subject firm of the SCBA. Given that Statoil had already

[40] Statoil at the time participated in a total of 34 producing oil fields (self-operated and non-operated).

initiated cost improvements in 1999 independent of any privatisation plans, however, this averaging might overestimate the true extent of privatisation-induced improvements. To be deliberately conservative in the accounting of privatisation benefits, we use the *minimum* value of the average cost ratio 1998-2000 and the year 2000 cost ratio, and apply this to the benchmark costs in the years post 2000.[41] For every year t the counterfactual cost per barrel C is thus calculated as:

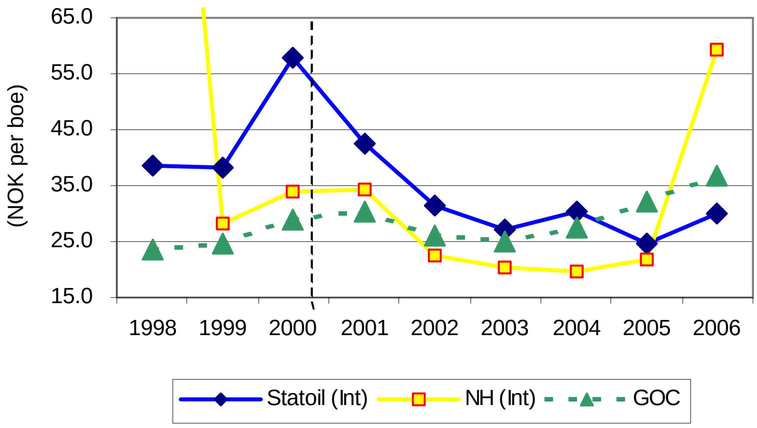
$$C_{G,t}^{STL} = C_{P,t}^{BM} \times min\{\frac{\sum_{t=1998}^{2000} \frac{C_{P,t}^{STL}}{C_{P,t}^{BM}}}{3}, \frac{C_{P,2000}^{STL}}{C_{P,2000}^{BM}}\} \qquad (8)$$

where STL is Statoil and BM is the respective cost benchmark used. As before, P is the factual scenario of part-privatisation and G is the counterfactual scenario of continued full government ownership. NH is used as the cost benchmark for counterfactual Scenario A, GOC as the benchmark for Scenario B.

International E&P in principle follows the same methodological logic as domestic E&P, but two issues of industrial substance need to be considered. First, the smaller a production portfolio, the more volatile and dependent on individual field characteristics its unit costs are. For this reason NH's international assets – with a tiny production of 3 kboe/d in 1998, growing to only 44 kboe/d in 2006 – cannot be considered an appropriate benchmark. Second, even for the use of GOC as a benchmark caveats need to apply. Contrary to its NCS operations, Statoil only operates the smaller part of the international assets itself. Also, most of its production outside Norway during the years 1998 to 2000 came from very mature or early-stage developments, and both types of assets are typically associated with higher unit costs (Statoil 2001, p.91). In the years since 2001, some of the mature fields have been closed down and some of the new developments have realised economies of scale, both implying a natural decline in unit production costs. On balance, operating cost improvements on the international upstream assets are excluded from the two basic counterfactual scenarios, but will be considered as part of the sensitivity analysis.

[41] For NH this minimum cost ratio is 1.00 and for GOC it is 0.85 (both are year 2000 values).

Figure 7: Factual production (lifting) costs per boe – international assets



Note: NH production cost in 1998 was NOK 165.0/boe (off scale)

For neither the Natural Gas or the M&M division are comparable cost benchmarks available. The main operating costs in Natural gas are related to NCS pipeline transport and to export pipeline transport on European gas sales. For M&M, the principal costs are cash operating costs in Statoil's refineries and its Methanol plant.[42] Because Statoil's official accounts do not provide a breakdown of intra-divisional costs at this level of granularity, we rely on the allocation estimate made by UBS Investment Research. Due to the lack of appropriate benchmarks no cost savings from either Natural Gas or M&M are included in Scenario A; for Scenario B, we assume counterfactual operating costs to be 5% higher – this is a simplified extrapolation of the results from NCS E&P, where average counterfactual unit costs (2001-06) were 3.9% (NH) and 7.2% (GOC) higher than the Statoil factual case. In both Natural Gas and the M&M division the operating costs included here are under the full control of Statoil management, and it seems reasonable to assume similar cost-cutting efforts as on self-operated upstream assets.

Overhead costs

Overhead costs, classified in Statoil's accounts as selling, general and administrative (SG&A) costs, are also difficult to benchmark. NH, for once, does not disclose a comparable accounting category. Even those industry peers that do list

[42] We ignore operating costs arising in petroleum retail, which is a 50/50 JV with the ICA/Ahold supermarket group, and in petrochemicals firm Borealis, 50%-owned by Statoil until its disposal in 2005. Both firms were treated in the accounts as equity affiliates.

overhead costs separately vary greatly in their definition, i.e. what kind of costs to be included. Comparing Statoil's SG&A cost over time (and benchmarking it against an inflation index) is also not straightforward as the asset portfolio changes over time.[43] In either case, the denominator of a unit cost measure is also difficult to define, which needs to be an index of corporate output across divisions. Based on an approximate analysis Statoil did manage to reduce its overhead costs per unit of output significantly in the period 1998 to 2000 (minus 23% compared to an industry peer average of plus 21%), but there is little evidence of a systematic outperformance in the period post 2000, which could be linked to partial privatisation.

Investment costs

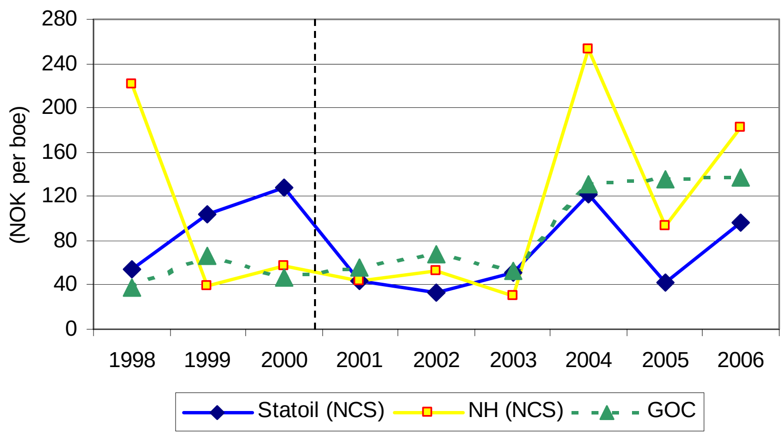
The oil and gas industry is highly capital intensive, and this is particularly true for challenging environments such as offshore deep-sea projects in rough waters. It was shown earlier that non-cash depreciation charges therefore account for the majority of technical costs in Statoil's upstream operations. For valuation purposes and to compute public profits, however, non-cash accounting charges are not particularly useful; instead, a cash-based measure is warranted that reflects investment efficiency. Part of the standardised SFAS 69 disclosure provides the annual costs incurred (both capitalised and expensed in the accounts) for oil and gas exploration and development activities. Together with the changes in hydrocarbon reserves for that year, they are used to calculate finding costs and finding and development (F&D) costs per barrel of proven reserves added, which have been shown to be good indicators of technical efficiency and future profitability (Boynton et al. 1999). If we assume – as before – the factual output generation as given (i.e. the new reserves found and created, and production drawn from these reserves), differences in F&D costs inform us of the additional investment that would have been required under continued state ownership to support such output.

As before for upstream operating costs, NH and GOC are used as cost benchmarks. To be particularly cautious in the base counterfactual scenarios, we only consider improvements in investment efficiency on the NCS (where Statoil operates most of its assets) and disregard the international operations. Furthermore, we take an

[43] The sale of 50% of the retail business to ICA/Ahold in 2000, for example, was responsible for SG&A savings of approximately NOK 1.4 billion in the first year, as disclosed in Statoil's AR. Other portfolio changes might be equally significant, but usually no detailed information is provided.

even stricter view on the historic cost ratio: following equation (8), the minimum historic cost premium of Statoil over the Norwegian assets of NH was 60.9%, and compared to GOC it was 74.9%. But because Statoil in 1999 was hit by the substantial cost overruns at the Asgard field, a one-off event that would have been addressed with or without privatisation plans, we completely disregard this historical cost difference and assume that, going forward, Statoil would have managed to operate at the same level of investment efficiency as its benchmarks.[44] As before NH is used as the benchmark for Scenario A, GOC for Scenario B.

Figure 8: Factual finding and development costs per boe – NCS assets



Quality and HSE externalities

Beyond volume, prices and costs, quality is another matter to consider in a SCBA, but often more difficult to pinpoint (Galal et al. 1994). Statoil, facing competitive markets and exporting much of its output, can be assumed not to have slipped in product quality. There is at least no evidence available to the contrary, neither in the form of negative press or consumer comments, or in the form of falling market shares. Statoil's legal stock market disclosures have also been reviewed, and there is no

[44] The original development budget for the entire Asgard project (including field, pipelines and land plant), calculated as of 1996, was NOK 31 billion. This was later revised upwards to NOK 47 billion, and in 1999 to NOK 64 billion. Even if we exclude the full NOK 33 billion increase, its net impact on Statoil (25% equity share) split over three years is NOK 2.75 billion, or only 23% of Statoil's average annual development costs on the NCS in the period 1998 to 2000. The provision therefore looks more than adequate. We also do *not* exclude any potential one-off charges in the factual Statoil numbers post 2001, such as the cost overruns at the Snoevit LNG project in the Barents Sea.

suggestion of systematic changes in the level of actual or pending lawsuits against the company.

Negative externalities – most commonly in the form of health, safety and environmental (HSE) matters – should also be considered. Amongst the environmental indicators disclosed by Statoil are emissions of CO_2 and NO_X, number and size of oil spills, discharge of harmful chemicals, energy consumption, gas flaring and waste recovery. Reported health and safety indicators include frequencies of recordable injuries, serious incidents and fatal accidents. On the majority of these metrics Statoil seems to have improved since partial privatisation. For example, data by the Norwegian authorities on overall CO_2 emissions on the NCS suggest that over the period 1999 to 2006 this has increased by approximately 20% per unit of petroleum output (NPD 2008). Statoil, on the contrary, reports an increase of only 4% over the same period. The difference would be 1.4 million tonnes in the year 2006[45], which – valued at €20 per tonne of CO_2 – would amount to approximately NOK 220 million per year. But because there are no comprehensive benchmarks available for most HSE metrics, and because it is yet unclear how much these results are impacted by individual asset characteristics, these externalities are not included in the two basic counterfactual scenarios.

Operatorship effects

As discussed in Section 4, any incremental value created by the part-privatised Statoil at its self-operated NCS upstream assets also accrues to its fellow shareholders in the projects and to the state as collector of taxes. This leverage effect of operatorship is therefore included in both scenarios. Statoil's accounts only reflect 33.1% (its production-weighted equity interest in 2006) of these incremental profits, but the 66.9% captured by other parties also need to be included in the SCBA.

Forecast period and terminal value of cost savings

As the terminal value period can carry significant weight in the calculation of net present costs or benefits, the assumption on the long-term development of cost differences is critical. In the absence of perfect foresight, there are equally valid reasons to believe that the differential might narrow or widen over time. Some

[45] Based on Statoil's 1999 emissions of 8.8 million tonnes.

previous SCBAs (e.g. Newbery and Pollitt 1997; Boardman et al. 2007) hence assume cost differentials to remain constant in the future.[46] Whilst we report the results of such an approach as part of the sensitivity analysis, the base case is again much more restrictive: it is assumed that any existing cost differential between factual and counterfactual in 2006 (the last year of historic data) will be reduced to zero by 2010 in four equal steps, with no cost differences at all arising in the terminal value period.

5 Results

5.1 The benefits of privatisation

Both counterfactual scenarios (with their different cost benchmarks) yield very comparable results as set out in Table 4. Across the two scenarios and the two different discount rates, the estimated net present value (NPV) of social benefits from part-privatisation of Statoil is between NOK 165.8 and 182.4 billion in 2001 money. At 2001 exchange rates this is between US$ 18.4 and 20.2 billion, at 2006 exchange rates between US$ 26.1 and 28.7 billion. The net benefit thus is 6.2-6.7 times greater than the original sales value of the 19.2% stake; even more impressively, it amounts to 11% of Norway's annual GDP in 2001.

Table 4: NPV of social benefits of Statoil privatisation relative to counterfactual

	CF Scenario A		**CF Scenario B**	
(NOK billion)	**6% DR**	**8% DR**	**6% DR**	**8% DR**
Operating costs				
E&P NCS	4.1	3.6	6.0	5.4
E&P Int'l	---	---	---	---
Natural Gas	---	---	2.2	2.0
M&M	---	---	0.5	0.4
Overhead costs	---	---	---	---
Investment costs				
E&P NCS	56.3	51.3	53.1	49.2
Externalities (HSE)	---	---	---	---
Operatorship effects				
Operating costs	8.2	7.2	12.1	10.9
Investment costs	113.8	103.7	107.3	99.4
Total benefits	**182.4**	**165.8**	**181.1**	**167.3**

[46] Pollitt and Smith (2002) assume gradual convergence of the cost differences, but over a forecast period of 15 years.

Although the benefits from NCS operating cost improvements are sizeable on their own, the reduced cost of investment delivers the vast majority of value. Also, in line with our assumption on the leverage effect of Statoil's NCS operatorships, the "external" effects contribute approximately two thirds of the total benefits from NCS cost savings. It is through this multiplier effect of operatorship that the part-privatisation of Statoil becomes so very successful.

Given the magnitude of benefits from investment savings, it is worth exploring them in some more detail. Both Statoil's NCS finding costs (cost of exploring for new reserves) and development costs (cost of commercially developing identified reserves) per barrel have fallen relative to NH and GOC benchmarks, but the differential is significantly greater for development costs, which account for 88% of Statoil 2001-06 F&D expenditures.[47] Anecdotal evidence, gathered from interviews and a review of Statoil's corporate disclosures, suggests that the part-privatised Statoil indeed pays greater attention to its investment planning and procurement function, and has increased its use of international contractors and competitive tender processes. It also seems clear that Statoil post privatisation receives less preferential treatment from the Norwegian petroleum authorities, and that the company – in the knowledge of these restrictions – has stepped up its efforts accordingly. As the U.S. Trade Representative observes in its 2006 country report on Norway: "Though the Norwegian government had in the past shown a strong preference for Norwegian petroleum companies in awarding the most promising oil and gas exploration and development blocks, foreign companies report no discrimination in recent licensing rounds." (USTR 2006)

For the distribution of welfare gains, and later for the sensitivity analysis, we will now focus on Scenario A at 8% discount rate (total social benefit of NOK 165.8 billion), as the differences to the other scenario are negligible. Following equation (5) the net social benefit to the Norwegian state *from the equity operations* of Statoil (i.e. excluding operatorship effects) is calculated as NOK 24.7 billion, 45% of the available total, and private shareholders receive 30.2 billion.[48] It is worth noting that although this result is based on the actual privatisation price received in 2001 – which

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[47] Statoil's volume-weighted 1998-2001 average NCS finding cost was NOK 10.92/boe, falling by 38% to NOK 6.83/boe for the period 2001-06. NH's finding costs over the same period fell by 24% (from NOK 7.64 to 5.83/boe). In terms of development costs, Statoil managed to lower them by 32% (from NOK71.71 to 48.72/boe), whereas NH's costs increased by 28% (from NOK 52.16 to 66.58/boe).

[48] Putting the numbers from our valuation model into equation (5) gives (errors from rounding):

$$\Delta Gov = 27.1 + 0 - 1{,}029.4 + 0.74 \times 1{,}084.3 + (1 - 0.192) \times (1 - 0.74) \times 1{,}084.3 - 0.7 = 24.7$$

with hindsight was too low because it reflected the then long-term oil price outlook of less than US$20 per barrel – the state still comes out positively. If the *true* oil prices had been anticipated, Statoil would probably have been sold for at least the equity value of the counterfactual scenario – NOK 48.0 rather than 27.2 billion for 19.2% of the company – and the difference would have been an additional transfer to the state. In that world of perfect foresight the private investors would still have made a net gain – paying NOK 48.0 billion for a stake worth NOK 53.6 billion after the efficiency improvements – but much less than they were able to make with the support of increasing oil prices.

Of the total public profits generated by NCS operatorship effects (NOK 110.9 billion), NOK 52.3 billion is taxation attributable to the state, and NOK 58.6 billion is private profit attributable to the fellow shareholders in Statoil-operated projects.[49] As set out earlier, the state itself very conveniently is the biggest co-owner in these projects, followed by NH, which again is 44% owned by the state. Hence NOK 32.0 billion of the "private" profit also accrues to the government.

Taken together, out of the NOK 165.8 billion of net social benefits as set out in Table 4, NOK 109.0 billion (or 66%) fall to the state, and only the remainder to private investors. In fact, because the state receives capital gains tax on the share profits made by Norwegian investors, and withholding tax or income tax on dividends received by all private shareholders, the balance is even more favourable in the sovereign's favour.

A different distributional matter of interest is the relative benefit accruing to Norwegians and foreigners, respectively. State benefits obviously fall to the Norwegian side, but so do the gains made by private Norwegian shareholders in Statoil and, to a lesser extent, Norsk Hydro. Foreign investors also hold shares in Statoil, Norsk Hydro and in the other oil companies that share ownership in Statoil-operated upstream assets. Based on share information in the Annual Reports 2001 to 2006, approximately 20-25% of private investors in Statoil and NH were Norwegian. No Norwegian shareholders are assumed to exist within the other international oil companies. Therefore Norwegian shareholders received NOK 7.8 billion of all private

[49] Although under Scenario A all cost savings are made in E&P NCS, which is subject to a 78% tax rate, the state's share of net benefits is smaller than this. This is because investment savings do not immediately impact on taxable income (as operating costs do) but only over time through a change in depreciation allowances – and this delay skews the present value in favour of private investors.

shareholder benefits, and foreign shareholders NOK 49.0 billion. Disregarding any differences in welfare weights, Norwegians (state and private) thus captured 70% of all social benefits from privatisation.

5.2 Valuation cross-check, sensitivity analysis and discussion

The relative development of Statoil's share price since privatisation is a useful cross-check on whether our estimate of welfare gains is too high. As pointed out earlier, in the period between June 2001 (privatisation IPO) and year-end 2006, Statoil's share price increased by 139% whilst a global index of oil and gas producing firms only gained 27%, both measured in Norwegian Kroner. As all shares will adjust to changes in global oil and gas prices, the difference between Statoil and the industry index can reasonably be ascribed to *unexpected*, firm-specific improvements at Statoil – since the privatisation price in 2001 probably reflected some anticipation of efficiency improvements, the incremental share price development would be somewhat smaller than the total value creation from privatisation. Based on Statoil's initial market capitalisation of NOK 149.4 billion, the difference in value creation for all shareholders is NOK 167.3 billion, and for the 19.2% of private shareholders it is 32.1 billion. This compares well with our estimated private welfare gain (*excluding* operatorship effects) of NOK 30.2 billion, suggesting that the base case estimate is not too high.

The SCBA welfare estimate nevertheless depends on a number of assumptions discussed earlier in this paper. To better understand their importance as value drivers, sensitivities are conducted relative to the "base case" of Scenario A at 8% discount rate. Table 5 shows the incremental change in social welfare from these changes, excluding any operatorship effects (including them magnifies all changes by a factor of approximately three).

Table 5: Results of sensitivity analysis

	NPV (NOK bn)	% of base value
Base: Welfare impact, Scenario A @ 8%, excl. operatorship effects	54.9	100%
Incremental impact of sensitivities:		
- E&P NCS operating cost differential based on 3-yr-avg.	+15.5	+28%
- Include historic cost differential for F&D costs	+94.5	+172%
- Include E&P International operating costs based on GOC	+2.9	+5%
- Natural Gas operating costs 5% higher	+2.0	+4%
- M&M operating costs 5% higher	+0.4	+1%
- Overhead costs (SG&A) 5% higher	+1.7	+3%
- Avg. cost differentials 2001-06 carried forward into TV	+84.4	+154%
-- same, but with 2% real term business growth in perpetuity	+129.4	+236%
-- same, but with 2% real term business decline in perpetuity	+63.3	+115%

The biggest incremental impact on net social welfare comes from the inclusion of the historic cost differences in calculating counterfactual F&D investment costs, which would add NOK 94.5 billion or 172% to the base case estimate of 54.9 billion. If the cost differentials on all cost items had been assumed to continue into perpetuity (rather than the rapid phasing out that has been chosen in the base case), this would have added 154% to the estimate of social benefits from privatisation. Assumptions on the long-term business growth or decline (in real terms) only matter for the SCBA if there are assumed cost differences in the terminal value period. Table 5 also shows the sensitivity results under the assumption of ongoing cost differentials, and 2% annual business growth or decline, respectively. The assumptions on operating costs in E&P International, Natural Gas and manufacturing and Marketing are less crucial for the overall result, as is the assumption on overhead cost savings.

In addition to these formal sensitivities, there is further upside to the base case estimate from the reduction of negative externalities (such as CO_2 emissions or recordable injuries), and from any increases in output – physical production and reserves replacement – due to privatisation. To simplify the analysis we have throughout assumed the factual output profile as given for the counterfactual cases, and solved for the necessary costs to support such output. It is conceivable, however, that pressure from the capital market at least accelerated the deployment of improved recovery technology on NCS fields, leading to a faster (and possibly higher) production from existing reserves.

A downside risk on the welfare estimate from E&P NCS operating costs comes from the fact that the trending up of NH benchmark costs between 2004 and 2006 is largely due to the cost of gas injection on the Grane field, which is expensive but part of the regular development plan in order to extract more oil (Hydro 2007). It might therefore be argued that comparing Statoil against this benchmark entails an unfair advantage for the privatised firm. Whilst this is somewhat true, Statoil until 2001 actually was a joint shareholder in Grane, selling its 2% interest to operator NH in a bid to streamline its asset portfolio and focus on other, more profitable projects. The fact that Statoil has no exposure to this high-cost field is thus a consequence of the pressures of privatisation, and the firm should be credited with the benefits of that decision.

The two sales of SDFI assets to Statoil in 2001 and to third parties in 2002 are adjuncts of the privatisation decision. The latter sale is likely to have generated further welfare benefits to the Norwegian state and the private project shareholders, which have not been taken into account in this paper. As far as the former sale is concerned, the “true” counterfactual would probably have been a Statoil without SDFI assets, but this would have made no difference to the analysis as in either case all of Statoil’s and SDFI assets are 100% state-owned and managed by Statoil. The transfer of these state assets to Statoil is widely acknowledged to be one of the main drivers of operational efficiency improvements, as the company was able to streamline technical infrastructure, decision-making and managerial incentives at the fields involved (MPE 2000). A valid question in this context is whether privatisation was necessary to reap these improvements, as the asset transfer could have been effected under continued state ownership as well. But Statoil should have had the incentive to realise such value opportunities all along – after all it managed both its own and the SDFI assets together under a common ownership structure – and apparently was unable (or unwilling) to do so without the pressures of the public capital markets. So in reality the transfer of SDFI assets to Statoil *without any increased public scrutiny* would not only have been unwanted by the state (in terms of increased power of the NOC), but would also not have generated the same incentives for cost improvement as under part-private ownership. What this illustrates, however, is that ownership changes on their own are no panacea, and that accompanying structural changes are often desirable or even required in order to realise increases in social welfare.

Two issues relating to the distribution of welfare changes should be briefly discussed as well. Firstly, it was assumed that employees were unaffected by Statoil's privatisation (other than as new shareholders). As the workforce was reduced substantially between 1998 and 2000, some of the producer benefits may have been transfers of rents from employees rather than net gains. But most of these reductions were a consequence of either asset disposals (i.e. people did not lose their job) or of the 1998/99 cost improvement programme which anteceded the privatisation decision.[50] Secondly, the estimate of total welfare change and its distribution differs dependent on the choice of shadow multipliers, and so far no difference between government and private funds was assumed. Whilst there are arguments in favour of a higher shadow weight for government, this is most appropriate in distorted economies or where acute fiscal constraints are in place. With consumption set to unity, Galal et al. (1994) suggest a central estimate of $\lambda_G = 1.33$, but argue that λ_P is also greater than unity, close to the government multiplier. Boardman at al. (2006) suggest $\lambda_G = 1.4$, and Moore at al. (2003) estimate λ_P for OECD countries such as the U.S. (1.10) and Canada (1.16). Norway, however, has been running a comfortable public budget surplus since the mid-1990s, and would have done so with or without the privatisation of Statoil. This strongly supports the case for the value of marginal government funds *not* to be greater than one, or at least not greater than the shadow multiplier of private investors' funds.[51]

6 Conclusion

This paper presented a social cost-benefit analysis of the part-privatisation of Norwegian state oil company Statoil in 2001, the first such empirical study to be conducted for the global oil and gas sector. SCBA is an analytical framework for systematically identifying the extent and distribution of costs and benefits of privatisation, based on comparing the factual outcome with a counterfactual scenario of continued state ownership. In the case of this paper, the plausibility of the

[50] Even if the 1998/99 programme was linked to preparations for privatisation, the overall welfare impact would be limited. Statoil in 1999 capitalised the full costs of redundancy payments as a provision of NOK 0.5 billion, and where contract terminations were voluntary this amount even overestimates the true cost (overcompensation of voluntary leavers).

[51] Another option on welfare weights is to assume a strictly Norwegian perspective, assigning zero weight to all foreign benefits, which amount to 30% of total welfare gains in the base case scenario discussed earlier.

counterfactual scenario benefits greatly from the existence of a privately-controlled benchmark company (Norsk Hydro) that is subject to virtually the same operating environment as the privatised firm. Unusually, this SCBA is also based on sufficiently detailed cost data to make the analysis on a divisional rather than a corporate level.

Based on a conservative set of assumptions – including that cost improvements only materialised in NCS upstream operating costs and investment costs, and that any cost differences existent in 2006 will be eliminated within four years – the privatisation of 19.2% of Statoil is estimated to have generated net present welfare benefits of NOK 166 billion (US$18.4 billion) in 2001 money. This amounts to 11% of Norway's 2001 gross domestic product of NOK 1,511 billion. Of the two sources of cost improvements, savings on investment costs have the much more material impact on welfare creation relative to operating costs. Only about one-third of the total benefits is generated within the accounting boundaries of Statoil, the remainder comes from the leverage effect of upstream operatorship: Statoil is the technical operator of about 60% of Norway's production, but only holds an average equity interest in self-operated fields of 33%. The other 67% equity interest, plus taxation on the entire projects, also benefit from any efficiency improvements at the operator that is Statoil.

Because the Norwegian state initially retained more than 80% equity interest in Statoil, and because it separately also owns direct financial interests in Statoil-operated fields, the state manages to capture 66% (NOK 109 billion) of the total welfare gains, leaving 4% to private Norwegian shareholders and 30% to international shareholders (all assuming no difference in shadow weights between government and the private sector). If at the time of privatisation the sales price had reflected the true future development of oil prices, then at least another 13% of the total balance might have shifted from the pockets of private investors to the state.

The share performance of Statoil relative to an index of industry peers serves as a useful cross-check for the estimate of social benefits, and its results suggest that our basic estimate is *not* too high. Along this same line, sensitivity checks on the core modelling assumptions reveal a number of potential sources of upside value.

Being mindful of this being a single company case study only, the findings nevertheless have multiple implications. First, they complement related privatisation studies of the oil sector (Wolf and Pollitt 2008) in showing that oil privatisation, if implemented appropriately within a competitive petroleum sector, can generate substantial improvements in corporate performance and efficiency, as well as in social welfare. Norway's very strong institutional attributes might not seem representative of other oil-exporting countries, but in terms of privatisation-induced performance improvements Statoil actually trails the average privatised NOC (Wolf 2008b). Second, the case study shows that even at well-run state-owned companies there might be scope for efficiency improvements though (partial) ownership change. Third, ownership change in itself is nevertheless no general panacea, and should (often needs to) be supported by complementary restructuring measures. In the case of Statoil, the sale of SDFI assets to the privatised firm, but also to third party competitors, served as an opportunity and incentive to realise available efficiency gains. Fourth, the timing of privatisation also matters: part-privatisation of Statoil in 2001 generated substantial welfare benefits, but strong state involvement in the earlier phases of sector development was probably one of the reasons that overall "few countries have been able to realize for its citizens a larger fraction of the potential value of a country's resources" (Stiglitz 2007, p.30). Fifth, the benefits from partial privatisation can be very substantial; transfer of full or even majority control is *not* necessarily required in order to implement a drive for operational improvements. Sixth, if structured carefully and if the state is not adverse to retaining some of the entrepreneurial risk, the relative share of benefits to the tax-paying public can be very meaningful indeed. For Statoil, of course, the high marginal tax rate of 78% on Norwegian upstream profits and the remarkable leverage effect of technical asset operatorship were important reasons for this outcome, but the overall structure of the transaction and of the state's involvement at multiple levels might be of interest to policy makers elsewhere.[52]

[52] One of the key attractions of the multiplier effect of technical operatorship is that it largely avoids the danger of underpricing (selling assets on the cheap), because very little is actually being sold.

List of acronyms and abbreviations

boe	-	Barrels of oil equivalent
DCF	-	Discounted cash flows
DD&A	-	Depreciation, depletion and amortisation
E&P	-	Exploration and production (upstream)
F&D	-	Finding and development costs
GFU	-	Norwegian Gas Negotiations Committee
GOC	-	Global OilCo
HSE	-	Health, safety and environment
kboe/d	-	Thousand barrels of oil equivalent per day
MPE	-	Norwegian Ministry for Petroleum and Energy
NPD	-	Norwegian Petroleum Directorate
NPV	-	Net present value
NH	-	Norsk Hydro
NOC	-	National oil company
NOK	-	Norwegian Kroner
OPEC	-	Organization of Petroleum Exporting Countries
PPP	-	Purchasing power parity
R&M	-	Refining and marketing (downstream)
SCBA	-	Social cost-benefit analysis
SDFI	-	State Direct Financial Interest
SFAS 69	-	Statement of Financial Accounting Standards No. 69
SG&A	-	Sales, general and administrative costs

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