Working Papers

Understanding Rig Rates

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CESifo Working Paper No. 4532
Category 10: Energy and Climate Economics
December 2013

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Abstract

We examine the largest cost component in offshore development projects, drilling rates, which have been high in recent years. To our knowledge, rig rates have not been analysed empirically before in the economic literature. Using econometric analysis, we examine the effects of gas and oil prices, rig capacity utilisation, contract length and lead time, and rig-specific characteristics on Gulf of Mexico rig rates. Having access to a unique data set containing contract information, we are able to estimate how contract parameters crucial to the relative bargaining power between rig owners and oil and gas companies affect rig rates. Our econometric framework is a single equation random effects model, in which the systematic part of the equation is non-linear in the parameters. Such a model belongs to the class of non-linear mixed models, which has been heavily utilised in the biological sciences.

JEL-Code: C180, C230, L140, L710, Q400.

Keywords: rig rates, oil and gas drilling, oil and gas prices.

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Thanks are due to Sven Ziegler, a number of specialists in oil and rig companies and Torbjørn Hægeland for useful suggestions and comments. We thank RS Platou for data and the Research Council of Norway for funding.

1. Introduction

High oil and gas prices over several years have been followed by increasing rates for renting oil and gas rigs. Drilling rates in the Gulf of Mexico (GoM) doubled in real prices from 2000-2004 to 2006-2008, see figure 1. Rates then fell dramatically in 2009 owing to the financial crisis, but have since recovered. High capacity utilisation (see figure 1) induces bottlenecks and lower average drilling quality, resulting in reduced drilling speed (Osmundsen et al 2010). The combined effect of increased rig rates and reduced drilling speed has generated a large increase in drilling costs, so that drilling can represent more than half of the development costs of an offshore petroleum field (Osmundsen et al 2012). As a consequence, the ratio between drilling costs and petroleum revenue has risen dramatically. From 1970 to 2005, total annual drilling costs in the USA never exceeded 35 per cent of total oil and gas revenues. In 2007-2010, the ratio was between 80 and 90 per cent each year. See figure 2.

"Figure 1 about here"

"Figure 2 about here"

It is therefore important to understand the crucial drivers for rig rates, including the effects of gas and oil prices on rig rates. This is the topic of the current paper, where we undertake econometric analyses of panel data for jackups in the GoM. Jackups are rigs used in shallow water, which stand on the floor to support the drilling deck.

Given the great importance of drilling in the offshore petroleum industry, and the fact that it represents in itself a large industry, it is surprising that we do not find any empirical studies in the academic literature analysing the formation of rig rates. The reason is probably lack of adequate data.

However, drilling activities have been studied in previous studies. Boyce and Nøstbakken (2011) show that the real oil price and the total number of wells drilled in the USA are highly correlated. Ringlund et al (2008) estimate the relationships between rig activity and the oil price, and find different price elasticities in different regions. Kellogg (2011) estimates learning-by-doing effects of drilling activity in Texas, and demonstrates the importance of the contractual relationship between oil and drilling companies. While these three studies focus on oil, Iledare (1995) estimates the effects of wellhead gas prices on natural gas drilling effort in West Virginia over the period 1977–1987.[1]

In our paper, we analyse a unique dataset from international offshore broker R S Platou that contains contract information and technical data for the rigs in the GoM, in particular rig rates, contract length and lead time. The GoM is a reasonably well defined submarket for jackups owing to moving costs and the difficulties of restaffing (Corts 2008). Floaters are also used in the GoM, but only in deeper waters. Thus, there is little or no direct competition between jackups and floaters.[2]

When oil and gas companies contract for drilling rigs, they primarily use short-term well-to-well contracts awarded through a bidding process among the owners of suitable nearby rigs (Corts 2008). Most of the GoM rig contracts have remuneration in the form of day rates (Corts 2000; Corts and Singh 2004). Even though producers do not physically drill their own wells, they do design wells and write drilling procedures, since producers typically have more geological information than drilling companies (Kellogg 2011).

[1] There exists a number of other related empirical studies of oil and gas exploration and development, see e.g. Lin (2009) for the GoM area, Kemp and Kasim (2003) for the UK Continental Shelf, and Mohn (2008) for the Norwegian Continental Shelf.

[2] In our dataset, the maximum technical depth of a jackup rig is 550 feet. As a comparison, in a corresponding dataset for floaters in the GoM, the smallest technical depth of a floater is 800 feet.

Rig rates are volatile, following a clear cyclical pattern. Not surprisingly, rig rates are highly sensitive to gas and oil prices and to capacity utilisation. We also examine the effect of contract length and lead time, build year, drilling depth capacity and rig classification. Rig rate formation is interesting in terms of the bargaining situation between rig owners and oil companies. With our access to contract data, we are able to test the effect of contract features such as contract length and lead time on pricing in a contract market. In a series of meetings with oil companies, rig companies and rig analysts, we have gained insight into the bargaining situation for rig rates. The relative bargaining power of rig owners and oil companies is likely to have an impact on the level of rig rates. Thus, factors that affect the relative bargaining power of the contracting parties form our *ex ante* hypotheses on rig rate formation.

Obviously, high current capacity utilisation in the rig industry is crucial to the bargaining power of the rig companies, and is – *ceteris paribus* – likely to lead to high rig rates. The same applies to high expected gas and oil prices, which make more development projects profitable and hence stimulate rig demand. However, jackup rigs are rented in a contract market, so that contract length and lead times also play a significant role. Longer lead times and an increase in the drilling companies' contract backlog enhance their bargaining power and is likely to lead to an increase in rig rates for new contracts.

In our econometric framework, we consider a random effects model where the parameters enter non-linearly in the systematic part of the equation. The non-linearity arises from representing the effects of gas and oil prices through a CES price aggregate. Our model can be considered a member of the nonlinear mixed effects type in the statistical literature (see eg, Vonesh and Chinchilli (1997); Davidian (2008) and Serroyen et al (2009)). Such models have been heavily utilised in the biological sciences, but have, to our knowledge, not been utilised previously for economic applications.

Our findings are specific results pertaining to the GoM jackup market, but the main conclusions are of a more general nature. As for the latter, the unique data set contains detailed contract information – in particular lead times and contract length – which generates results on how contract structure affects pricing. The hypotheses of our industry panel are confirmed. Not only gas and oil prices and capacity utilisation, but also contract length and lead time positively affect rig rates. High capacity utilisation occurs in periods with high gas and oil prices, ie, higher gas and oil prices may not only have a direct effect on rig rates, but also an indirect effect by increasing the utilisation rate. Rig rates only partly respond to a sudden shift in gas and oil prices – oil and gas companies wait for some months to see if the price change is more permanent before they increase rig demand. Gas prices are much more important than oil prices for changes in rig rates, which is consistent with the fact that jackups in the GoM area are used mostly for gas drilling. A shortage of the future supply of rigs, represented by an increase in lead times, is shown to lead to an increase in rig rates. A longer contract length has similar effects. As for market specifics, we find that rig rates are almost proportional to the technical depth capacity of the rig.

The remainder of the paper is organised as follows. Section 2 outlines the theoretical background for our empirical analysis. The econometric approach is developed in section 3. Section 4 describes our data, and empirical results are presented in section 5. Section 6 concludes.

2. Theoretical background

In this section, we will motivate the empirical model by using a simple analytical framework which includes the most important variables in our model.

2.1 Oil and gas companies' demand for rigs

Oil and gas companies use rigs to explore for oil and gas, and to develop oil and gas fields. They typically have a number of projects with different expected profitability, and the expected value of each project is increasing in the expected prices of gas (p^G) and/or oil (p^O). For some projects, eg, developing a gas or oil field, only one of these prices may be of importance, whereas for other projects – such as exploration for or development of an oil field with associated gas – both prices may be important. Let π denote the price of renting a rig (rig rate). The net benefits from using r rigs within a time period may then be expressed as $B(p^G,p^O,r) - \pi r$, with $B_{p^G}, B_{p^O} > 0$, $B_r > 0$ and $B_{rr} < 0$ (B_x and B_{xy} denoting the first and second derivative of B with respect to x, and x and y respectively).[3] The benefit function is concave in r because the company prioritises the most valuable projects ahead of less valuable projects. Thus, the number of rigs rented is given by:

$$B_r(p^G, p^O, r) = \pi \tag{1}$$

which gives the following demand function for rigs: $D(p^G,p^O,\pi)$, where $D_{p^G}, D_{p^O} > 0$ and $D_\pi < 0$.

2.2 Rig market

Rig companies own a fixed number of rigs in a given period. The rigs are somewhat heterogeneous, and we might think of the rig market as one with monopolistic competition. Although we do not specify a complete model with heterogeneous products, we assume that each rig company has some

[3] Strictly speaking, the number of rigs is not a continuous variable, and thus the derivative with respect to r should rather be replaced with the change in B given a unit increase in r. Furthermore, it is the *expected* net benefits that matter here. Since the purpose of this theoretical section is to motivate the empirical model, however, we have omitted expectations. Below, we return to the question of how price expectations are formed.

market power (cf. Lee and Jablonowski, 2010). Let firm i own R^i rigs, and let r^i denote the number of rigs the firm rents out. We may think that the alternative costs of renting out rigs are increasing in r^i. For instance, rigs need maintenance, and there are costs of transporting rigs between different locations. Furthermore, the alternative cost depends on the number of rigs the company owns – if r^i gets close to R^i, it seems reasonable that the alternative cost increases faster. Thus, let $c(r^i, R^i)$ denote the alternative costs of renting out r^i rigs, with $c_r > 0$ and $c_{rr} > 0$, and $c_R < 0$. We may further assume that the cost function is homogeneous of factor one, so that a doubling of r^i and R^i doubles the costs. The term "alternative costs" refers, eg, to the fact that a rig not rented out today may be rented out tomorrow, whereas a rig rented out today will not be available for a new contract until the current contract terminates.

Let $D^i(p^G,p^O,\pi^i)$ denote the demand function that rig company i faces, where $\sum D^i(p^G,p^O,\pi) = D(p^G,p^O,\pi)$ when the rig rate is identical across companies. By inverting this function, we get the inverse demand function $\pi^i(p^G,p^O,r^i)$, with $\pi^i_{p^G}, \pi^i_{p^O} > 0$ and $\pi_r < 0$. Thus, r^i is given implicitly by:

$$\pi^i_r(p^G, p^O, r^i)r^i + \pi^i(p^G, p^O, r^i) = c_r(r^i, R^i)$$

or

$$\pi^i_r(p^G, p^O, u^iR^i)u^iR^i + \pi^i(p^G, p^O, u^iR^i) = c_r(u^i)\,, \tag{2}$$

where $u^i = r^i/R^i$ denotes the utilisation rate of company i. The last equation then follows from the homogeneity assumption. With normal demand functions D, we then have that both r^i (or u^i) and π^i increase in p^G and p^O.

What about u, the aggregate utilisation rate in the rig market? It seems reasonable to argue that the degree of competition in the market depends on the number of available rigs. That is, if the utilisation rate is high, each rig company will acquire more market power as the inverse demand function it faces becomes steeper (fewer available substitutes, ie, rigs). Assuming that the utilisation rate in period *t*+1 is correlated with the utilisation rate in period *t*, it also seems reasonable to assume that the alternative cost of renting out rigs depends on the aggregate utilisation rate. Thus, we may extend the equation above:

$$\pi_r^i(p^G, p^O, r^i, u)r^i + \pi^i(p^G, p^O, r^i, u) = c_r(r^i, R^i, u)$$

or

$$\pi_r^i(p^G, p^O, u^i R^i, u)u^i R^i + \pi^i(p^G, p^O, u^i R^i, u) = c_r(u^i, u)\,. \tag{3}$$

A steeper inverse demand function implies in general that marginal revenue falls. Hence, this tends to reduce r^i (or u^i) and increase π^i. Thus, if some shock (eg, higher p^j) leads to a higher r^i (and u^i) and thus u (and higher π^i), the second-order effect will be to dampen the increase in r^i and u, increasing π^i further. Including u in the estimations should therefore be expected to have a positive effect on π, whereas omitting u may be expected to increase the effect of a change in p^j (since p^j and u will tend to be correlated). In meetings with rig companies, oil companies and rig analysts, we have learnt that rig rates tend to increase in particular when capacity utilisation in the rig fleet reaches 98%.

2.3 More on the effects of gas and oil prices

So far, we have simply stated that both gas and oil prices may affect the demand for rigs. We now turn to the question of how price expectations are formed, and discuss how gas and oil prices may interact in the demand function for rigs, $D(p^G,p^O,\pi)$.

Price expectations for oil and gas are usually assumed to be adaptive (see eg, Farzin (2001), Nguyen and Nabney (2010) and Aune et al (2010)). That is, expected prices *t* periods into the future are assumed to depend on current and past prices. However, the weighing of current versus past prices is not clear, and will typically depend on the time horizon. In our context, we are typically thinking of projects that generate income several years into the future, but there are significant differences between the time horizons for exploratory drilling and for drilling additional wells in a developed field. We will use price indices for gas and oil that are weighted sums of the current prices and the price indices in the previous period, and leave it up to the estimations to determine the relative weights. The price indices, which we will refer to as smoothed prices, are specified in the next section.[4]

Although some companies specialise in either oil or gas extraction, most companies in this industry are involved in both types of extraction. Many petroleum fields contain both gas and oil, and the actual content is often not revealed before test drilling has been undertaken. Oil and gas reserves are usually imperfect substitutes to the companies, because they require different types of skills and capacity. In particular, gas is more challenging in terms of transport. A common way of modelling imperfect substitutes is to use a constant elasticity of substitution (CES) function. Thus, we will consider a CES aggregate of gas and oil reserves, and let the estimation determine both the elasticity of substitution and the relative importance of the two resources. A large elasticity means that gas and oil are almost perfect substitutes and, in the limiting case where elasticity verges on infinity, the benefits of gas and

[4] An alternative modelling approach would be to represent market expectations about future petroleum prices by oil and gas futures prices. Pindyck (2001) argues however that the expected future spot price will usually exceed the futures price due to risk adjustment. Moreover, from discussions with oil companies we learn that they do not use futures prices when they form price expectations, at least not beyond 12 months. The reason they give is the lack of liquidity in these markets, relative to the large volumes they need to trade. The volume of Henry Hub natural gas futures is generally reduced by 99 per cent after half a year (http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html). In the literature, lack of liquidity and regional limitations is mentioned as drawbacks for NYMEX gas futures by Brinkmann and Rabinovitch (1995). Modjtahedia and Movassagh (2005) find that the the bias in the natural gas futures prices is time varying.

oil are fully separable. Thus, the more common assumption of separable, linear functions of oil and gas prices can be seen as a special case of the CES function we apply.

Given the CES structure, we can furthermore construct a price index for the CES aggregate. See the next section. Above, we argued that the rig rate increases in line with gas and oil prices. In the empirical model below, we will specify a log-linear function of the CES price aggregate (of smoothed gas and oil prices).

2.4 Other variables

The modelling above treats all rigs as identical, but assumes at the same time that they are heterogeneous. We have some information about heterogeneous characteristics of the rigs, such as rig category and technical depth capacity. These are assumed to affect the contract rates, and are treated as dummy (eg, rig categories) or ordinary variables (eg, technical depth). The contract structure is vital to rig rate determination. Our unique data set contains detailed contract information, in particular lead times and contract length.

3. Econometric approach

From an econometric point of view, our framework is a non-linear random effects model. Our model specifications may also be considered as special cases of a non-linear mixed effects model, see Vonesh and Chinchilli (1997) and Davidian (2008). We consider the following econometric relationship

$$\begin{aligned}
&\log(RIGRATE_{is}) = \beta_0 + \beta_1 \times \log(PCES_{is}(\alpha_{gas}, \alpha_{oil}, \delta, \sigma)) + \beta_2 \times \log(1 - UTIL_{is}) \times (1 - HIGHUTIL_{is}) \\
&+\beta_3 \times HIGHUTIL_{is} + \beta_4 \times LEAD_{is} + \beta_5 \times CONT_{is} + \beta_6 \times BUILD_i + \beta_7 \log(DEPTH_i) + \\
&\sum_{m=2}^{4} \gamma_m \times DUMCATm_i + \sum_{j=1991}^{2009} \lambda_j \times DUMj_{is} + \mu_i + \varepsilon_{is}.
\end{aligned} \tag{4}$$

The individual rigs have the status of observational units. They are denoted by subscripts *i* (rig number), whereas subscript *s* denotes the observation number.[5] Most of the variables in (4) are both rig- and contract-specific, and thus have both subscripts. This also includes the CES price aggregate, since *s* denotes the observation number and not time. If the observation number *s* for two rigs is from the same period, however, the variable will take the same value for both observational units. $PCES_{is}(\alpha_{gas},\alpha_{oil},\delta,\sigma)$ denotes the CES aggregate of smoothed real gas and oil prices on index form (see below), where α_{gas} and α_{oil} denote smoothing parameters for gas and oil prices respectively, δ is a distribution parameter and σ the substitution elasticity. The price index $PCES_{is}$ is calculated for the time period (month) when the contract is signed.

The symbol $UTIL_{is}$ denotes the capacity utilisation rate lagged by one month (relative to when the contract is signed). The variable $HIGHUTIL_{is}$ equals 1 if the observation number *s* from observational unit *i* corresponds to a period where the capacity utilisation is higher than or equal to 0.98, otherwise it is zero. According to equation (4), the response to capacity utilisation is thereby represented by the log of spare capacity, $\log(1-UTIL_{is})$, when capacity utilisation is below 0.98, and by $HIGHUTIL_{is}$ when capacity utilisation exceeds or is equal to 0.98. This distinction is based on information from the rig industry, see section 2.[6]

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[5] One reason for letting *s* denote the observation number for a specific observation unit is that there may be more than one observation from an observational unit in a given period of time.

[6] Note that equation (4) implies that $\frac{\partial \log(RIGRATE)}{\partial \log(UTIL)} = \frac{-\beta_2 \times UTIL}{1-UTIL}$ for capacity utilisation below 98%, which implies that the elasticity of the rig rate with respect to the capacity utilisation rate is higher the higher the capacity utilisation rate. An additional reason for representing the effect of a high capacity utilisation rate by a dummy variable is that, for some periods, the capacity utilisation rate equals 1, and in this case log(1-*UTIL*) is not defined.

The next four variables are $LEAD_{is}$, $CONT_{is}$, $BUILD_i$ and $\log(DEPTH_i)$ respectively. Note that the two latter variables are time-invariant covariates. $LEAD_{is}$ is the time lag between the fixture date (when the contract is signed) and the start date of the rental period, whereas $CONT_{is}$ denotes the contract length. $BUILD_i$ represents the build year and $DEPTH_i$ the technical drilling depth of rig *i*. $DUMCATm_i$ are binary variables taking the value 1 if rig *i* is of type *m*, otherwise they are zero. There are four types of jackups in our dataset, and rig rates may, *ceteris paribus*, differ among different rig types.[7] The first type is the reference type, whose level is taken care of by the intercept. We have also added year dummies. $DUMj_{is}$ is 1 if observation number *s* from observational unit *i* occurs in year *j* (*j*=1991, …, 2009). The random effect μ_i for rig *i* is assumed to be normally distributed, with variance $\sigma_{\mu\mu}^2$, and ε_{is} denotes a genuine error term. We assume that the genuine errors are normally distributed white noise errors with a variance given by $\sigma_{\varepsilon\varepsilon}^2$.

The main reasons for considering a random effects specification are the presence of time-invariant covariates and the fact that the model is non-linear in the parameters. The effect of time-invariant variables is not identified in fixed effects models unless further assumptions are introduced.

As argued in section 2, price expectations for oil and gas companies are assumed to be adaptive. Hence, we implicitly construct smoothed gas and oil prices that are weighted averages of current and historic prices. Let us assume that observation number *s* for rig number *i* is from period *t*(*s*). The smoothed gas price ($PGASS_{is}$) and the smoothed oil price ($POILS_{is}$) corresponding to this observation are then assumed to follow a Koyck lag structure, see Koyck (1954):

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[7] The four types are *independent leg cantilever jackups* (*m* = 1), *independent leg slot jackups* (*m* = 2), *mat supported cantilever jackups* (*m* = 3), and *mat supported slot jackups* (*m* = 4). Independent leg jackups are used on a firm sea floor, while mat supported jackups are used on a soft floor. Cantilever jackups are now more common than slot ones. For more information, see eg, http://www.rigzone.com/training/insight.asp?insight_id=339&c_id=24.

$$PGASS_{is}(\alpha_{gas}) = \alpha_{gas} \sum_{j=0}^{T} (1-\alpha_{gas})^j \, PGAS_{t(s)-j} , \tag{5}$$

$$POILS_{is}(\alpha_{oil}) = \alpha_{oil} \sum_{j=0}^{T} (1-\alpha_{oil})^j \, POIL_{t(s)-j} , \tag{6}$$

where $PGAS_t$ and $POIL_t$ are the real prices of gas and oil in period t.[8] The two smoothed variables defined in (5) and (6) enter as arguments in the CES price aggregate after having been converted to price indices.[9] The two indices are labelled $PGASSI_{is}(\alpha_{gas})$ and $POILSI_{is}(\alpha_{oil})$ respectively. Thus, the CES price aggregate is given by:

$$PCES_{is}(\alpha_{gas}, \alpha_{oil}, \delta, \sigma) = \left[\delta\left(PGASSI_{is}(\alpha_{gas})\right)^{1-\sigma} + (1-\delta)\left(POILSI_{is}(\alpha_{oil})\right)^{1-\sigma} \right]^{\frac{1}{1-\sigma}} . \tag{7}$$

Note that the CES price aggregate is a function of four unknown parameters, ie, the smoothing parameter of gas, α_{gas}, the smoothing parameter of oil, α_{oil}, the distribution parameter, δ, and the substitution parameter, σ. When all these four parameters are known, the left-hand side of (7) may be viewed as an observable variable.

Maximum likelihood estimates are obtained using PROC NLMIXED in the SAS statistical software. To provide starting values for the maximisation, we make use of a grid search involving the

[8] In principle, the sum should include price levels even longer back than T periods. However, the smoothed oil prices and gas prices would then be very similar compared with the ones we obtain here. We use T=143, which means that we use a filter spanning 12 years. For low values of α_{gas} and α_{oil}, the sum of the weights is lower than one. In these cases, we have rescaled the weights by dividing them by the sum of the weights such that the modified weights sum to one.

[9] The smoothed prices of gas and oil are converted to indices by dividing by the value of the smoothed prices in the first period, ie, 1990M2.

parameters α_{gas}, α_{oil}, δ and σ. Note that when these parameters are known, equation (4) is a linear (in parameters) random effects model, which is easy to estimate. Under the grid search, we only consider cases where $\alpha_{gas} = \alpha_{\text{oil}} = \alpha$. To generate starting values, we have considered 2,717 different model specifications. In table B1 in Appendix B, we list the parameter values employed in the grid search. The parameter estimates of the model with the highest log likelihood value are used as starting values in the final maximum likelihood estimation in which all parameters are treated symmetrically.[10]

We also consider model specifications which deviate somewhat from the one specified in equation (4). In particular, we sometimes omit the capacity utilisation variables. The purpose of this is to examine the total effect, ie, both direct and indirect effects, of an increase in the gas and oil price index when capacity utilisation is allowed to respond to the price change. The indirect effect is when an increase in gas and oil prices stimulates rig rates via increased capacity utilisation. We would expect the rig rates to respond more strongly to price changes in this case than in the main model (see the theory discussion in section 2).

4. Data

The observational units in this paper are jackup rigs in the GoM. The main data source is provided by the R S Platou company, see table 1. Altogether, we use data for 204 jackups. The dataset contains four different jackup categories (see footnote 7).[11] The dependent variable in our analysis is the rig rate. A rig is rented for a certain period of time in accordance with a contract between the rig company and the petroleum licence represented by the operator. We have information about the fixture date, ie, the date when the contract is signed, as well as the starting and end dates for each contract. From the

[10] As the optimising algorithm in PROC NLMIXED, we have applied the thrust-region method (TRUREG). This method requires calculation both of the gradient and of the Hessian matrix of the objective function.

[11] A small number of the rigs change type during the sample period, and these rigs are omitted from our analysis.

amount of money paid for the whole contract period, it is possible to deduce a daily rig rate. The daily rig rates are in current money and we have deflated them by a producer price index to obtain rig rates in constant prices.

The data are on a monthly basis, and the timing refers to the point in time when the contract was signed.[12] We possess data for many of the rigs over a substantial period of time, and hence have information on different contracts for a specific rig.[13] The data set is thus an (unbalanced) panel data set. In Appendix A, we give an overview of the unbalancedness of the panel data set. The number of observations for a rig varies from 1 to 92.

The most important explanatory variables in our estimations are gas and oil prices. For the gas price, we use US wellhead prices taken from the EIA, whereas for the oil price we use the Brent Blend price. These prices are deflated by the same price index as rig rates.

The data from RS Platou also provide information on capacity utilisation of jackups in the GoM area. The data distinguish between capacity utilisation rates for active rigs and for all rigs. Based on discussions with rig analysts, we use the former in our analysis.[14] As the capacity utilisation rate

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[12] As mentioned above, we have information about fixture, start and end date for each contract. However, one problem with the data is that the fixture date is often reported to fall after the start date. The reason is that the reported fixture date is when the contract is officially announced, which is often after the handshake date. We then follow the assumptions applied by R S Platou, which are to set the fixture date 50 days before the start date of the contract whenever the former comes after the latter in the data.

[13] Our estimation sample spans the period 1990M2 to 2009M10.

[14] Active rigs are defined as rigs that are actively marketed, whereas passive rigs comprise units that are cold stacked for shorter or longer period, in yard, or en route from one body of water to another. For an interesting analysis of decisions by drilling companies to idle (“stack”) rigs in periods with low dayrates, see Corts (2008).

applies to the whole GoM area, it is equal for all observations from the same time period. From a theoretical point of view, one may argue that the capacity utilisation rate should not enter linearly in the model – it seems probable, for example, that rig rates are more sensitive to increases in capacity utilisation rates when these rates are high (ie, a convex relationship could be expected). This is captured by our model specification for utilisation rates up to 98% (for higher rates we use a dummy, as explained above).

A special feature of the panel data used in this analysis is that one may have more than one observation for a rig at a specific point of time. The reason is the lead time from when the contract is signed to the period when the rig is involved in a specific drilling project. This delay is represented by an independent variable in our analysis (*LEAD*). Since the owner of the rig may make different contracts for the same rig for disjunctive time periods ahead, it follows that one may have more than one observation for the same rig at a given point of time. As a consequence of this somewhat rare data design, we find it convenient to use the index *s* to indicate the observation number for a specific rig. We will use the index *t* to indicate calendar time when we need to be explicit about time.

In table 2 below, we report some summary statistics for the variables utilised in the current analysis. The total number of observations is 6,801. The capacity utilisation rate shows considerable variation over the sample period.

"Table 1 about here"

"Table 2 about here"

5. Estimation results

Estimation results for our most general model, with separate smoothing parameters for gas and oil prices, are reported in the left-hand part of table 3. In the right-hand part of the table, we report results for a constrained model in which we have omitted the two variables representing capacity utilisation (see below). In both cases, the estimates of the two smoothing parameters are not very different. The hypothesis of a common smoothing parameter for gas and oil may be tested by performing an LR test. Table 4 reports the estimation results when we assume identical smoothing parameters for gas and oil prices.

Let us first consider the case with the capacity utilisation variables included. The value of the LR statistic is then equal to -2×(227.681-228.864)=2.366 (see the left-hand parts of tables 4 and 3 respectively). Using the χ^2-distribution with 1 degree of freedom, one obtains a significance probability of 0.124. The corresponding significance probability in the constrained case with no capacity utilisation variables is 0.823 (see the log likelihood values in the right-hand parts of tables 4 and 3 respectively). Thus, in both cases, we do not obtain rejection of the hypothesis using conventional significance values. Hence, we will concentrate in the following on the case with a common smoothing parameter. We start by taking a closer look at the estimates reported for the model specification with capacity utilisation variables in the left-hand part of table 4.

First, we notice that the estimate of the common smoothing parameter for gas and oil prices, α, is 0.069. This means that when the expected gas and oil price index is updated every month, the current price has a weight of 6.9%, whereas the expected price in the previous month has a weight of 93.1%. By expected price, we refer here to the gas and oil price expectations companies have for their future sales of gas and oil, which are assumed to influence the rig market. Thus, an estimate of 0.069 implies that gas and oil companies will respond only partly to a sudden shift in gas and oil prices – they will wait for some months to see if the price change is more permanent. This is consistent with the industry's practice.

Furthermore, we see that the distribution parameter, δ, is estimated to be 0.763. Hence, gas prices are much more important than oil prices for changes in rig rates. This is consistent with the fact that jackups in the GoM area are mostly used for gas drilling. We also notice that the estimate of the substitution elasticity, σ, equals 4.83, which is a fairly high value. This is also as expected, since jackups may be used for both gas and oil drilling.

"Table 3 about here"

Next, we see that the CES aggregate of gas and oil price, not surprisingly, enters with a highly significant effect. Given our model specification, the long-run price elasticity is equal to the estimate of the parameter attached to the price variable, β_1. Since the estimate is 1.234, this means that a 10% permanent increase in the gas and oil price index increases rig rates by 12.3%. This assumes the other variables in the model – particularly capacity utilisation – to remain unchanged.

"Table 4 about here"

It is relevant to look at immediate, medium-term and long-term price elasticities with respect to gas and oil prices, ie, how the rig rate responds to changes in the gas and oil price over time. We have derived the necessary formulae in Appendix C. Under some simplified assumptions, we show that the immediate gas and oil price elasticities are given by formulae (C18) and (C19) respectively. The corresponding medium- and long-term elasticities are given by formulae (C20) and (C21). In figure 3, we display the estimated elasticities for the two models, for which we report results in table 4. Using the full model (ie, with capacity utilisation variables included), the long-term gas and oil price elasticities are 0.94 and 0.29 respectively. The corresponding immediate elasticities are 0.065 and 0.020. After nine months, half of the adjustment to a new permanent price has taken place (see the two solid curves in the figure). It follows from our assumptions that the gas and oil price elasticities show the same pattern over time. There is only a scale difference, which stems from the presence of the estimated distribution parameters in the formulae, see the formulae in Appendix C referred to above. The results of using the model without capacity utilisation variables are discussed below.

"Figure 3 about here"

Next, we see from table 4 that the effect of capacity utilisation is also highly significant. The estimated parameter value suggests that, if the share of non-contracted rigs is reduced by 10%, eg, by increasing the capacity utilisation from 90% to 91%, rig rates increase by 1.6%. This is illustrated in figure 4, where we show the impacts on rig rates when capacity utilisation is changed, given the estimation results (the figure is constructed around the point where capacity utilisation and rig rate both equal their mean values, see table 2). We see from the figure that the rig rates will typically increase by 20 per cent if capacity utilisation rises from 60% (lowest observed value) to above 98%, that is, if other variables stay constant. However, a typical situation is that high capacity utilisation occurs in periods with high gas and oil prices, see the discussion in section 2. In other words, higher gas and oil prices may not only have a direct effect on rig rates, but also an indirect effect via the increase in the utilisation rate, at least in the short to medium term.

"Figure 4 about here"

Thus, it is of interest to estimate a model where capacity utilisation is excluded in order to examine the full effects of an increase in gas and oil prices. The estimation results of such a model are presented in the right-hand part of table 4. Based on the reasoning above, we should expect the short-run (and medium-run) price elasticity to increase, but probably not the long-run elasticity (when supply and demand in the rig market are balanced). This is exactly the case, according to the results in the right-hand part of table 4. We observe that the estimated value of α has increased from 0.069 to 0.101, whereas the estimated gas and oil price parameter is only marginally changed. The estimate of the distribution parameter is also almost unchanged. Thus, the estimated long-run price elasticities are fairly similar to those for the full model, whereas the immediate responses have increased by almost a half. Besides, the adjustment is somewhat faster. This is illustrated in figure 3, which shows that half of the adjustment to permanently higher gas and oil prices occurs within six months (see the dotted curves). However, we see from the log likelihood values of the two models in table 4 that a large and significant drop in explanatory power is obtained when the parameters attached to the two capacity utilisation variables are forced to be zero. Thus, capacity utilisation is undoubtedly an important factor in determining rig rates.

The other (non-dummy) variables are also highly significant, and the estimated parameter values are almost the same in the two panels of table 4, ie, with and without capacity utilisation as a variable. In particular, we notice that rigs able to drill at greater depths are significantly more expensive than rigs only able to operate in shallower waters. The estimated parameter value indicates an elasticity of 0.84, that is, rig rates are almost proportional to the technical depth capacity of the rig. This is illustrated in figure 5, which is constructed in the same way as figure 4. The estimation results furthermore show that rigs built more recently are more expensive than older rigs – the estimation results indicate that 10 years' difference amounts to a 7% change in rig rates. This is due to advances in technology and rig design – new rigs have higher capacity and more functions than older units.

"Figure 5 about here"

Figure 5 furthermore shows that both the length of the contract and the lead time, ie, the time from the contract is signed until the rental period starts, have significant, positive effects on the rig rate. In a period of increasing demand, rig availability is lower. The lead times and the rig companies' contract backlog increases, their relative bargaining power is enhanced and rig rates rise. The estimated value indicates that, when the lead time increases by six months, the day rate goes up by around 3.8%.

Similarly, according to these estimations (see figure 5), we find that extending the contract length by six months increases the day rate by around 2.6%.

Some but not all of the rig category dummies are significant.[15] According to our results, the most valuable jackup category seems to be the *independent leg slot jackup*, after controlling for other characteristics such as drilling depth and build year. The rig rate for this category is estimated to be 14% higher than for the *independent leg cantilever jackup*. According to the industry specialists we have interviewed, this is somewhat surprising, since this rig category is not being built anymore. Note, however, that differences in both build year and technical depth are captured by separate variables. The limited number of rigs available in this category is also put forward as an explanation for this result (10% of the sample, see table 2).[16]

6. Conclusions

The relative bargaining power of rig owners and oil companies is likely to have an impact on the level of rig rates. Thus, factors that affect the relative bargaining power of the contracting parties form our *ex ante* hypotheses on rig rate formation. A unique dataset from the GoM rig market allows us to test the relationship between contract data and pricing in a contract market.

Our econometric analysis of GoM jackup rig rates confirms the hypotheses of our industry panel. Obviously, high current capacity utilisation in the rig industry is crucial to the bargaining power of the

[15] Whereas the log likelihood value is 227.681 (see the left-hand part of table 3) in our main model, it is 220.797 in the model specification without rig category dummies. Thus, using an LR-statistic, the hypothesis that the three slope parameters attached to these dummies are zero is rejected at the 1% significance level.

[16] We have also performed separate estimations for rig types 1 and 3, which together account for 75% of the observations. The main conclusions carry over. The estimation results can be made available by the authors upon request.

rig companies, and leads to high rig rates. The same applies to high expected gas and oil prices, which stimulate gas and oil development projects and hence increase rig demand. Consistent with industry practice, however, petroleum companies only partly respond to sudden shifts in the gas and oil prices – they wait for some months to see if the price change is more permanent. Consistent with the fact that jackups in the GoM area are used mostly for gas drilling, we find that gas prices are much more important than oil prices for changes in rig rates.

Since this is a contract market, contract length and lead times also play a significant role. In periods of high demand, the increase in the lead times and the contract backlog enhances the bargaining power of the rig companies and leads to a rise in rig rates for new contracts.

In this study, we have considered a non-linear random effects model and estimated all the unknown parameters by maximum likelihood. Models of these types have been heavily utilised in the biological sciences. Even though they are relevant for several economic applications, too, we are not aware of earlier econometric studies utilising such models.

In our estimations, we have implicitly treated the GoM area as a closed market, since capacity utilisation and gas prices in other parts of the world have not been included. This could be a weakness with our analysis, as some movement of rigs takes place between areas. Since it is quite costly to move rigs over large distances, however, we believe that this omission is of minor importance.

Whereas jackups are mainly used in shallow water (and on land), oil and gas companies use floaters when they drill in deep water. Whether the market for renting floaters has similar characteristics as the jackup market is an interesting question we leave for future research. Floaters are typically rented for longer periods than jackups, and thus the backlog of future contracts may be even more important for the rig rates.

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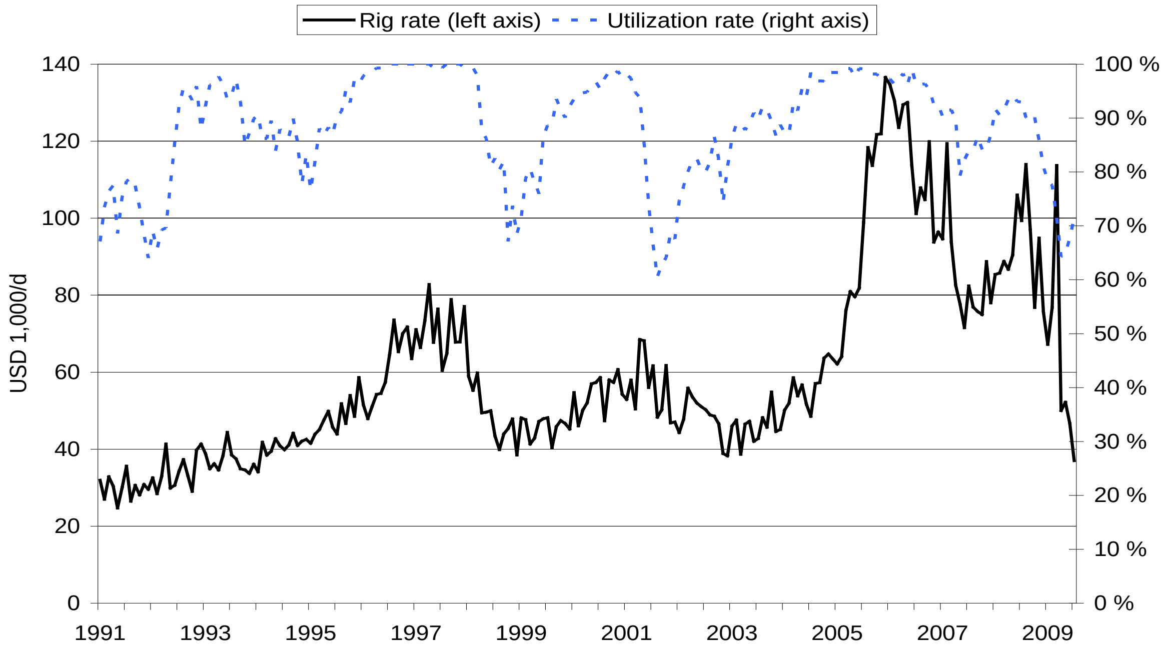
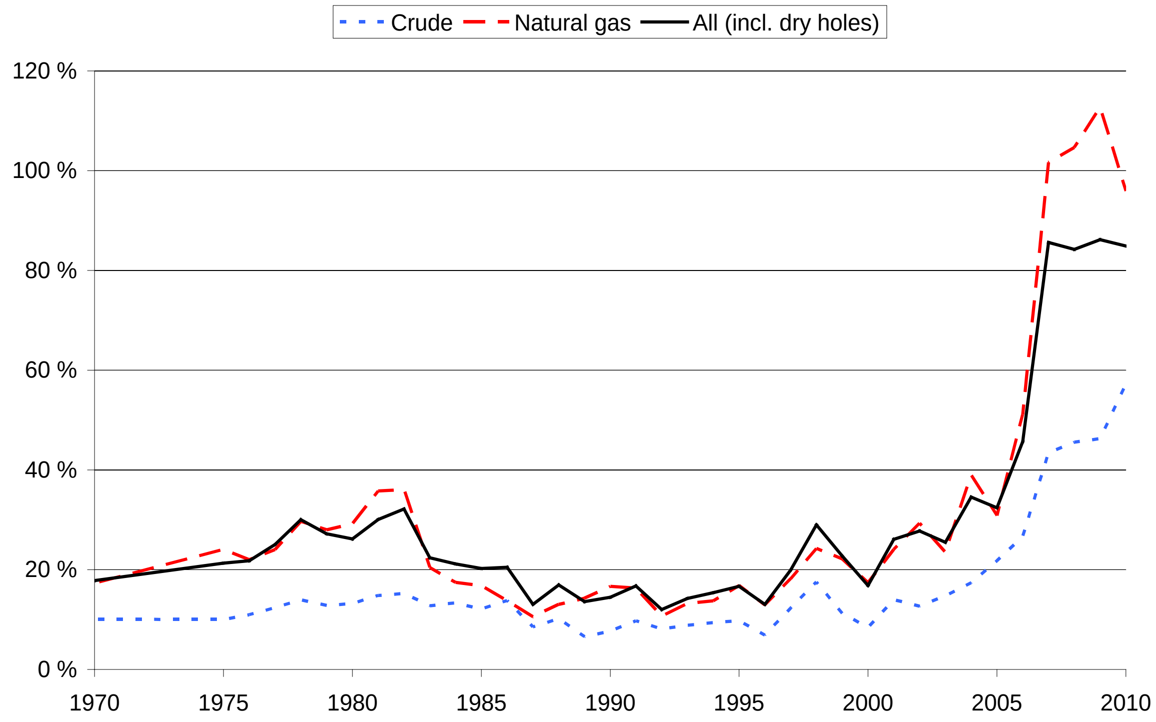
Figure 1: Rig rates and capacity utilisation rates for jackups in the GoM from 1991 to 2009. Monthly unweighted average of rig rates in real prices (USD 1,000 per day in 2008 value)



Note: Capacity utilisation rates for active rigs.

Source: R S Platou

Figure 2: Ratio of annual drilling costs to annual revenues of oil and gas production in the USA from 1970 to 2010



Source: EIA (2011)

Figure 3. Estimated immediate, medium-term and long-term gas and oil price elasticities based on the full model and the model without capacity utilisation variables

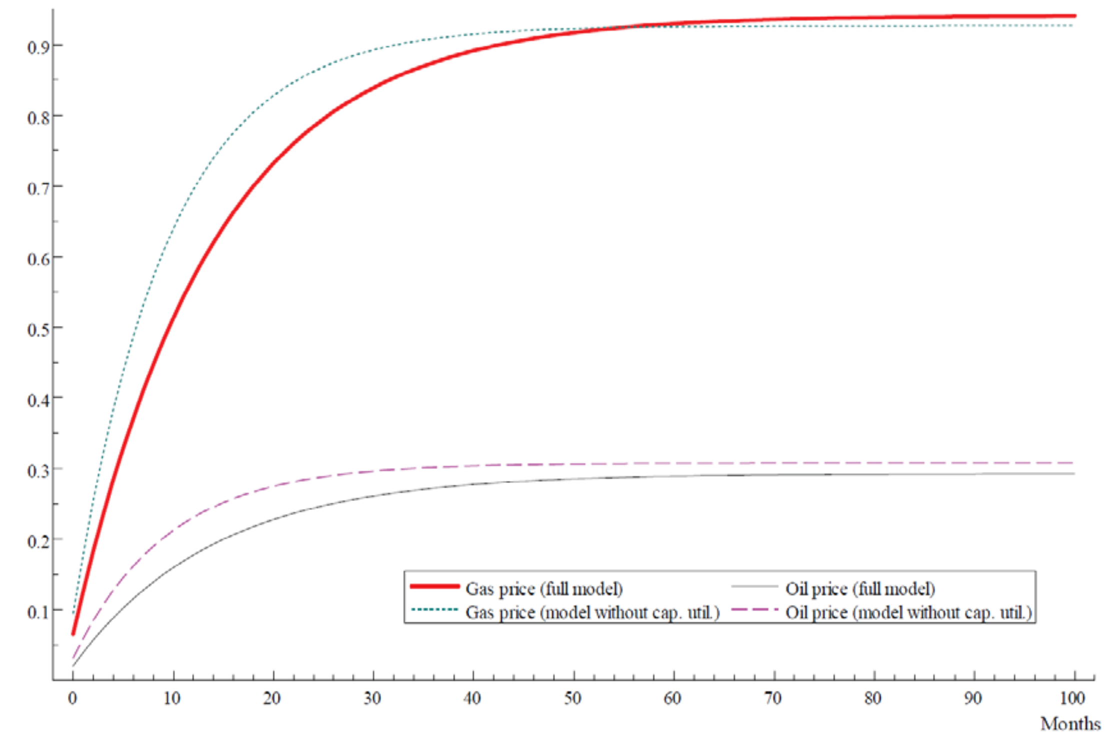


Figure 4. Effects of capacity utilisation on rig rates. USD 1,000 per day

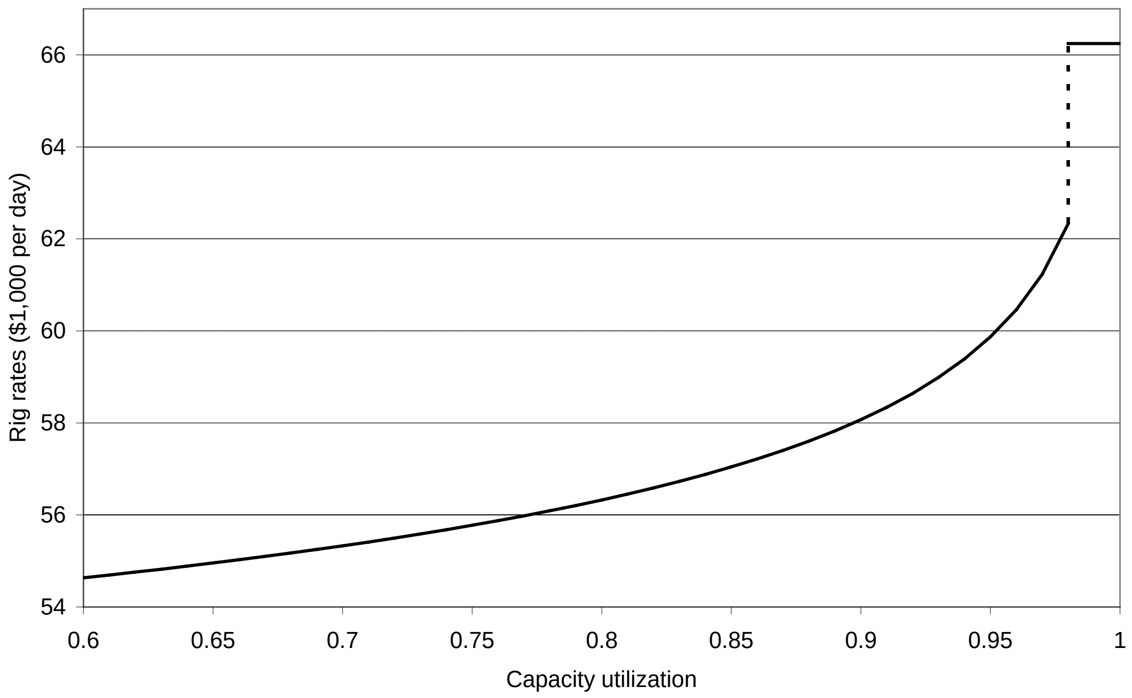
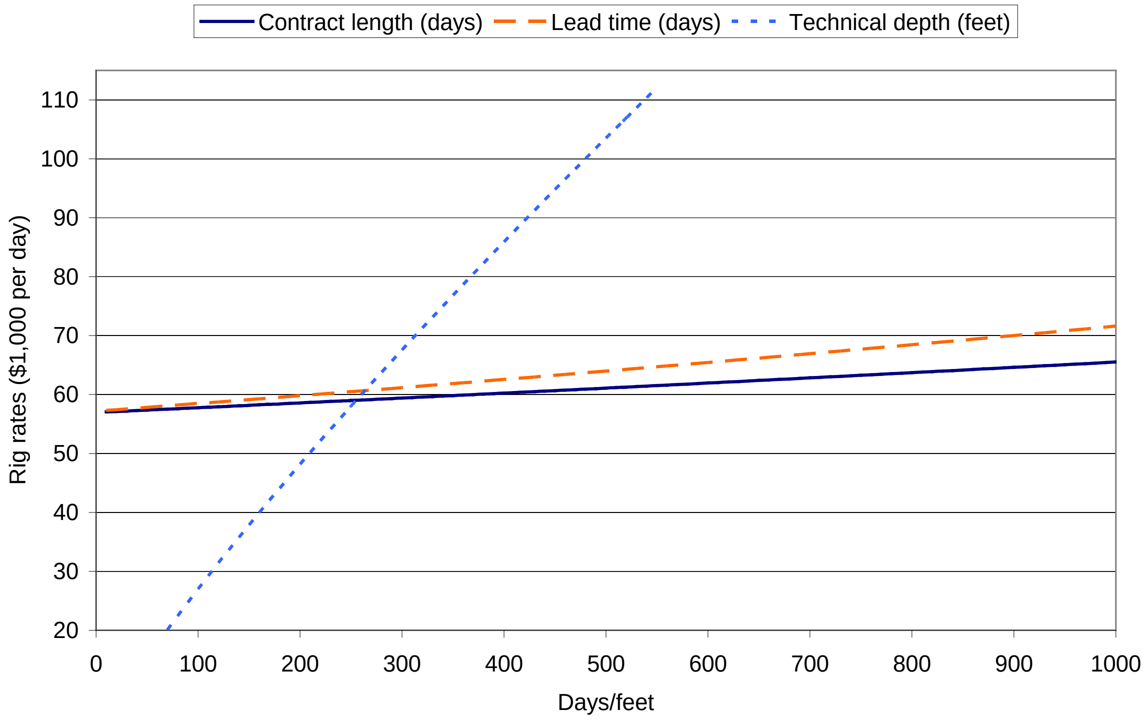


Figure 5. Effects of technical depth, contract length and lead time on rig rates. USD 1,000 per day



Note: Each curve is constructed around the point where the independent variable (contract length, lead time or technical depth) and the rig rate both equal their mean values, see table 2.

Table 1. Data sources and unit of measurement

Variable	Variable name	Source	Unit of measurement
Rig rates in current prices	*RIGRATE*	R S Platou	USD/d
Gas price in current prices (US wellhead price)	*PGAS*	EIA	USD/tcf
Oil price in current prices (Brent Blend)	*POIL*	Petroleum Intelligence Weekly??	USD/bbl
Deflator for rig rates and oil price		US Bureau of Labor Statistics	Index variable
Capacity utilisation rates (for jackups in GoM)	*UTIL*	R S Platou	Ratio
Lead time	*LEAD*	R S Platou	Days
Contract length	*CONT*	R S Platou	Days
Build year	*BUILD*	R S Platou	Year
Technical depth	*DEPTH*	R S Platou	Feet
Dummies for rig type	*DUMCATm*[a]	R S Platou	Dummy variables

[a] $m \in \{2, 3, 4\}$.

Table 2. Summary statistics of variables[a]

Variable name	Mean	Std dev	Min	Max
RIGRATE[b]	57,827	33,681	9,230	270,211
PGAS[b]	4.29	2.20	1.80	11.65
POIL[b]	39.6	22.8	12.8	131.2
UTIL	0.89	0.094	0.60	1
LEAD	49.0	52.6	0	1981
CONT	108	164	1	4382
BUILD	1980	5.03	1958	2010
DEPTH	249	82.8	70	550
DUMCAT1	0.47	0.50	0	1
DUMCAT2	0.10	0.30	0	1
DUMCAT3	0.29	0.45	0	1
DUMCAT4	0.14	0.35	0	1

[a] The total number of observations is 6,801.
[b] In constant 2008 prices.

Table 3. Maximum likelihood estimates of the non-linear random effects model, assuming separate smoothing parameters for gas and oil

	Model with capacity utilisation variables		Model without capacity utilisation variables	
Parameters/explanatory variables	Estimate	t-value	Estimate	t-value
Smoothing parameter for gas (α_{gas})	0.055	5.93	0.098	7.61
Smoothing parameter for oil (α_{oil})	0.078	7.41	0.102	11.92
Distribution parameter (δ)	0.806	11.06	0.757	11.67
Substitution elasticity (σ)	5.639	2.71	6.172	4.57
log[*PCES*($\hat{\alpha}_{gas}, \hat{\alpha}_{oil}, \hat{\delta}, \hat{\sigma}$)][a]	1.302	12.90	1.283	17.66
log[*1-UTIL*]×(*1-HIGHUTIL*)	-0.045	-5.79	0[b]	
HIGHUTIL	0.239	8.55	0[b]	
CONT/100	0.014	7.02	0.014	6.94
LEAD/1000	0.225	4.01	0.228	4.04
BUILD/100	0.733	3.81	0.725	3.75
log(*DEPTH*)	0.835	22.09	0.834	22.03
DUMCAT2	0.142	3.07	0.141	3.04
DUMCAT3	0.055	1.50	0.056	1.52
DUMCAT4	-0.042	-1.05	-0.040	-1.00
Constant	-8.499	-2.25	-8.209	-2.17
*DUM*1991	-0.272	-2.43	-0.336	-3.03
*DUM*1992	-0.233	-2.08	-0.310	-2.83
*DUM*1993	-0.186	-1.67	-0.233	-2.14
*DUM*1994	-0.115	-1.04	-0.160	-1.46
*DUM*1995	0.157	1.43	0.138	1.27
*DUM*1996	0.276	2.49	0.314	2.89
*DUM*1997	0.316	2.82	0.357	3.27
*DUM*1998	0.163	1.46	0.215	1.96
*DUM*1999	0.058	0.52	0.038	0.35
*DUM*2000	-0.154	-1.37	-0.247	-2.25
*DUM*2001	-0.404	-3.51	-0.420	-3.64
*DUM*2002	-0.442	-3.89	-0.488	-4.30
*DUM*2003	-0.679	-5.81	-0.717	-6.17
*DUM*2004	-0.709	-5.87	-0.722	-6.04
*DUM*2005	-0.622	-4.99	-0.586	-4.75
*DUM*2006	-0.367	-2.82	-0.371	-2.80
*DUM*2007	-0.560	-4.24	-0.606	-4.68
*DUM*2008	-0.664	-4.94	-0.757	-5.76
*DUM*2009	-0.831	-6.07	-0.817	-6.02
Variance of random component, $\sigma^2_{\mu\mu}$	0.025	8.48	0.025	8.46
Variance of genuine error term, $\sigma^2_{\varepsilon\varepsilon}$	0.051	57.39	0.052	57.39
Log likelihood value	228.864		180.980	
Observations	6,801		6,801	
Observational units	204		204	

[a] A ^ above a parameter denotes the estimate of the parameter.

Table 4. Maximum likelihood estimates of the non-linear random effects model, assuming common smoothing parameters for gas and oil

	Model with capacity utilisation variables		Model without capacity utilisation variables	
Parameters/explanatory variables	Estimate	t-value	Estimate	t-value
Smoothing parameter (α)	0.069	8.63	0.101	15.20
Distribution parameter (δ)	0.763	9.58	0.751	12.56
Substitution elasticity (σ)	4.830	3.03	6.119	4.62
log[*PCES*($\hat{\alpha}$, $\hat{\delta}$, $\hat{\sigma}$)][a]	1.234	13.69	1.278	18.56
log[*1-UTIL*]$\times$(*1-HIGHUTIL*)	-0.044	-5.64	0[b]	
HIGHUTIL	0.233	8.25	0[b]	
CONT/100	0.014	7.02	0.014	6.93
LEAD/1000	0.225	4.02	0.228	4.04
BUILD/100	0.733	3.81	0.725	3.76
log(*DEPTH*)	0.835	22.10	0.834	22.03
*DUMCAT*2	0.142	3.06	0.141	3.04
*DUMCAT*3	0.055	1.51	0.056	1.52
*DUMCAT*4	-0.042	-1.05	-0.040	-1.00
Constant	-8.491	-2.25	-8.212	-2.17
*DUM*1991	-0.291	-2.62	-0.337	-3.05
*DUM*1992	-0.262	-2.38	-0.312	-2.86
*DUM*1993	-0.223	-2.05	-0.235	-2.17
*DUM*1994	-0.144	-1.32	-0.160	-1.47
*DUM*1995	0.141	1.30	0.139	1.28
*DUM*1996	0.253	2.32	0.313	2.88
*DUM*1997	0.288	2.63	0.356	3.27
*DUM*1998	0.141	1.29	0.215	1.96
*DUM*1999	0.039	0.35	0.039	0.35
*DUM*2000	-0.171	-1.54	-0.247	-2.24
*DUM*2001	-0.399	-3.49	-0.416	-3.64
*DUM*2002	-0.429	-3.78	-0.484	-4.31
*DUM*2003	-0.661	-5.67	-0.713	-6.20
*DUM*2004	-0.679	-5.64	-0.717	-6.11
*DUM*2005	-0.581	-4.69	-0.580	-4.82
*DUM*2006	-0.324	-2.50	-0.366	-2.91
*DUM*2007	-0.519	-3.93	-0.601	-4.73
*DUM*2008	-0.640	-4.71	-0.754	-5.77
*DUM*2009	-0.781	-5.66	-0.810	-6.16
Variance of random component, $\sigma^2_{\mu\mu}$	0.025	8.48	0.025	15.20
Variance of genuine error term, $\sigma^2_{\varepsilon\varepsilon}$	0.051	57.39	0.052	57.39
Log likelihood value	227.681		180.955	
Number of observations	6,801		6,801	
Number of observational units	204		204	

[a] A ^ above a parameter denotes the estimate of the parameter.

Appendix A. Further information on data

Table A1. The unbalancedness of the panel data[a]

No of obs for an obs unit	Number of rigs being obs the indicated no of times	No of obs	No of obs for an obs unit	Number of rigs being obs the indicated no of times	No of obs
1	11	11	2	6	12
3	7	21	4	4	16
5	6	30	6	3	18
7	3	21	8	7	56
9	0	0	10	3	30
11	4	44	12	3	36
13	2	26	14	1	14
15	3	45	16	4	64
17	2	34	18	0	0
19	2	38	20	4	80
21	1	21	22	3	66
23	2	46	24	1	24
25	0	0	26	2	52
27	3	81	28	0	0
29	2	58	30	1	30
31	2	62	32	1	32
33	5	165	34	1	34
35	3	105	36	1	36
37	8	296	38	3	114
39	0	0	40	5	200
41	2	82	42	4	168
43	3	129	44	7	308
45	2	90	46	2	92
47	5	235	48	4	192
49	5	245	50	2	100
51	2	102	52	2	104
53	3	159	54	3	162
55	3	165	56	3	168
57	5	285	58	2	116
59	1	59	60	1	60
61	1	61	62	3	186
63	0	0	64	1	64
65	2	130	66	0	0
67	0	0	68	1	68
69	3	207	70	0	0
71	0	0	72	0	0
73	1	73	74	4	296
75	0	0	76	0	0
77	1	77	78	0	0
79	0	0	80	2	160
81	0	0	82	0	0
83	0	0	84	0	0
85	0	0	86	2	172
87	1	87	88	0	0
89	1	89	90	0	0
91	0	0	92	1	92

[a] The total number of observational units and the total number of observations are 204 and 6,801, respectively.

Table A2. The number of observations in each time period[a]

Period	No of obs.	Period	No of obs	Period	No of obs	Period	No of obs
1990M2	2	1990M3	0	1990M4	1	1990M5	1
1990M6	0	1990M7	1	1990M8	0	1990M9	0
1990M10	0	1990M11	0	1990M12	0	1991M1	4
1991M2	1	1991M3	0	1991M4	1	1991M5	4
1991M6	4	1991M7	9	1991M8	14	1991M9	32
1991M10	35	1991M11	13	1991M12	21	1992M1	20
1992M2	15	1992M3	14	1992M4	25	1992M5	19
1992M6	23	1992M7	23	1992M8	23	1992M9	29
1992M10	26	1992M11	27	1992M12	30	1993M1	24
1993M2	27	1993M3	26	1993M4	25	1993M5	23
1993M6	30	1993M7	32	1993M8	29	1993M9	27
1993M10	35	1993M11	35	1993M12	36	1994M1	26
19940M2	43	1994M3	29	1994M4	42	1994M5	39
1994M6	36	1994M7	48	1994M8	34	1994M9	45
1994M10	33	1994M11	35	1994M12	30	1995M1	35
1995M2	31	1995M3	34	1995M4	43	1995M5	45
1995M6	28	1995M7	37	1995M8	36	1995M9	38
1995M10	45	1995M11	41	1995M12	36	1996M1	36
1996M2	39	1996M3	31	1996M4	35	1996M5	39
1996M6	37	1996M7	36	1996M8	32	1996M9	37
1996M10	24	1996M11	31	1996M12	27	1997M1	28
1997M2	30	1997M3	28	1997M4	23	1997M5	38
1997M6	34	1997M7	30	1997M8	37	1997M9	27
1997M10	21	1997M11	38	1997M12	29	1998M1	29
1998M2	31	1998M3	35	1998M4	25	1998M5	34
1998M6	26	1998M7	22	1998M8	29	1998M9	31
1998M10	27	1998M11	32	1998M12	30	1999M1	25
1999M2	36	1999M3	32	1999M4	36	1999M5	34
1999M6	30	1999M7	45	1999M8	33	1999M9	28
1999M10	41	1999M11	37	1999M12	26	2000M1	32
2000M2	32	2000M3	38	2000M4	25	2000M5	40
2000M6	47	2000M7	40	2000M8	37	2000M9	37
2000M10	30	2000M11	49	2000M12	40	2001M1	46
2001M2	36	2001M3	80	2001M4	40	2001M5	49
2001M6	40	2001M7	37	2001M8	31	2001M9	11
2001M10	37	2001M11	28	2001M12	33	2002M1	32
2002M2	27	2002M3	30	2002M4	38	2002M5	34
2002M6	50	2002M7	41	2002M8	27	2002M9	47
2002M10	28	2002M11	36	2002M12	30	2003M1	44
2003M2	36	2003M3	33	2003M4	39	2003M5	35
2003M6	36	2003M7	40	2003M8	45	2003M9	31
2003M10	44	2003M11	40	2003M12	29	2004M1	36
2004M2	44	2004M3	38	2004M4	41	2004M5	37
2004M6	32	2004M7	51	2004M8	29	2004M9	32
2004M10	30	2004M11	40	2004M12	47	2005M1	41
2005M2	32	2005M3	38	2005M4	44	2005M5	41
2005M6	46	2005M7	37	2005M8	37	2005M9	23
2005M10	42	2005M11	60	2005M12	34	2006M1	38
2006M2	22	2006M3	25	20060M4	14	2006M5	27
2006M6	22	2006M7	13	2006M8	27	2006M9	22

‘

Table A2. (continued)

Period	No of obs	Period	No of obs	Period	No of obs	Period	No. of obs.
2006M10	18	2006M11	35	2006M12	28	2007M1	23
2007M2	16	2007M3	26	2007M4	27	2007M5	18
2007M6	23	2007M7	11	2007M8	21	2007M9	13
2007M10	28	2007M11	22	2007M12	20	2008M1	12
2008M2	25	2008M3	29	2008M4	32	2008M5	28
2008M6	25	2008M7	24	2008M8	17	2008M9	23
2008M10	25	2008M11	14	2008M12	20	2009M1	9
2009M2	10	2009M3	15	2009M4	11	2009M5	14
2009M6	5	2009M7	7	2009M8	6	2009M9	13
2009M10	3						

[a] The total number of observations is 6,801.

Table A3. Rig categories involved

General category description	Rig category number used in current paper
Independent leg cantilever jackups	1
Independent leg slot jackups	2
Mat supported cantilever jackups	3
Mat supported slot jackups	4

Figure A1. Capacity utilisation rates for jackups in the Gulf of Mexico area

Figure A2. The oil price in current US dollars

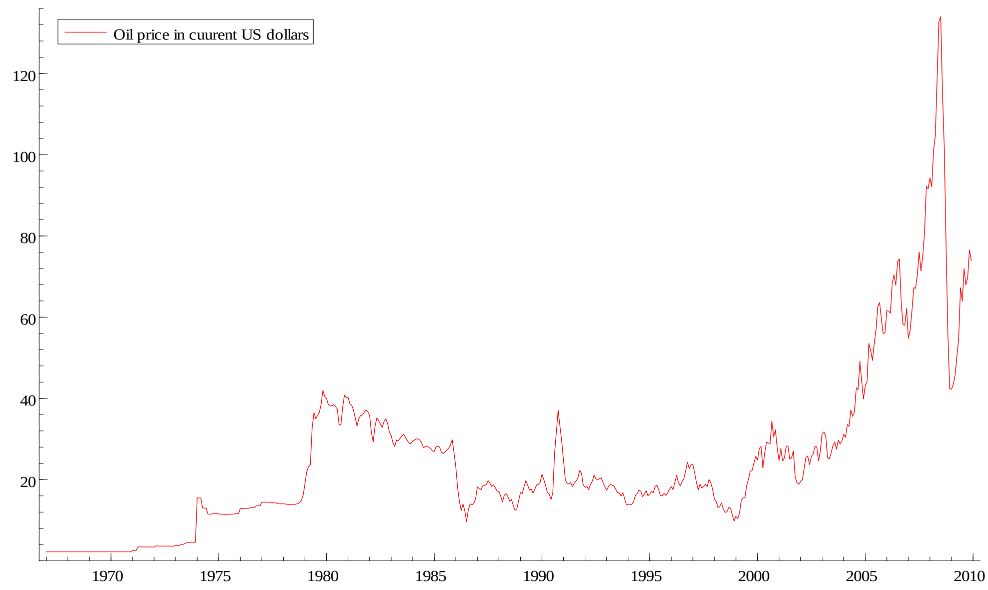


Figure A3. US natural gas wellhead price (dollars per thousand cubic feet)

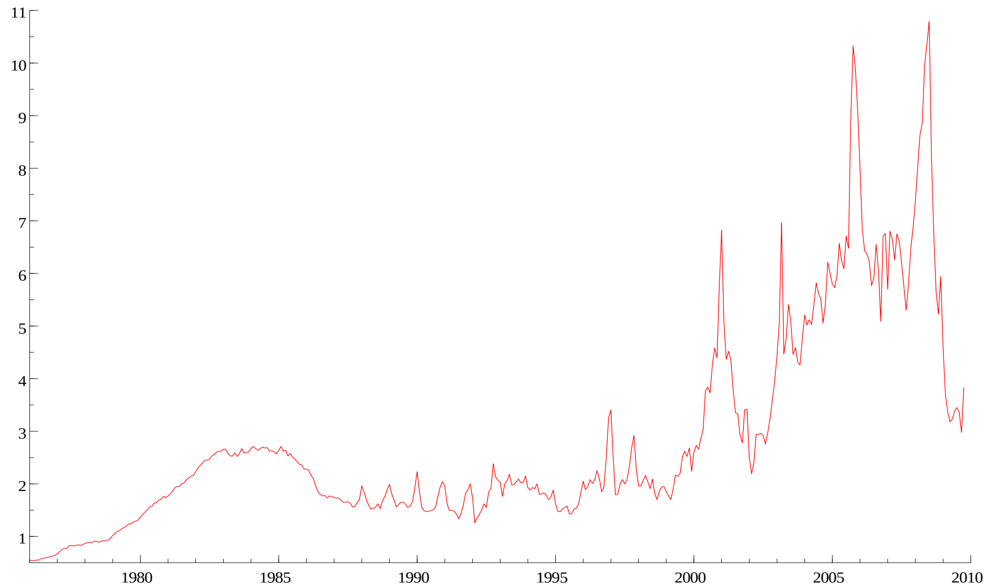
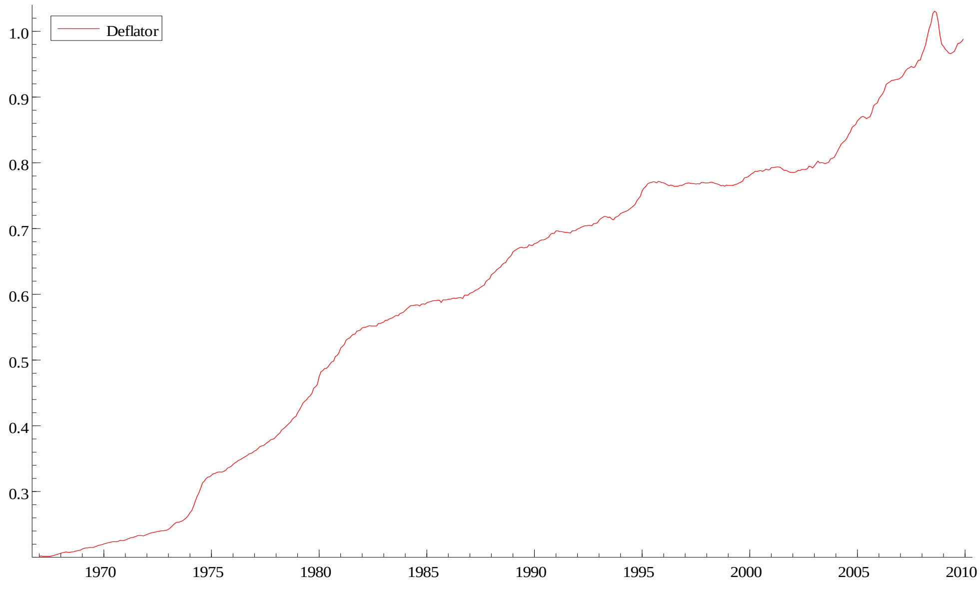


Figure A4. The price deflator – 2008=1



Appendix B. Additional information on the grid search used to obtain starting values

Table B1. Parameter values used in the grid search

α	δ	σ
0.03	0.1	0.1
0.04	0.2	0.3
0.05	0.3	0.5
0.06	0.4	0.7
0.08	0.5	0.95
0.10	0.6	1.5
0.12	0.65	2
0.15	0.7	2.5
0.20	0.75	3
0.25	0.80	4
0.30	0.85	5
	0.90	6
	0.95	8
		10
		12
		14
		16
		18
		20

Appendix C. Short-, medium- and long-term rig-rate elasticities with respect to gas and oil prices

Our CES aggregate of gas and oil prices is given as

$$PCES_t(\alpha,\delta,\sigma) = \left[\delta\left(PGASSI_t(\alpha)\right)^{1-\sigma} + (1-\delta)\left(POILSI_t(\alpha)\right)^{1-\sigma}\right]^{\frac{1}{1-\sigma}},$$

(C1)

where $PGASSI_t(\alpha)$ and $POILSI_t(\alpha)$ are indices of smoothed gas and oil prices respectively. They are formally defined as

$$PGASSI_t(\alpha) = PGASS_t(\alpha)/PGASS_{1990M2}(\alpha), \tag{C2}$$

$$POILSI_t(\alpha) = POILS_t(\alpha)/POILS_{1990M2}(\alpha), \tag{C3}$$

where the smoothed gas and oil prices at period t is given by

$$PGASS_t(\alpha) = \frac{\alpha}{1-(1-\alpha)^{T+1}} \sum_{j=0}^{T} (1-\alpha)^j PGAS_{t-j}, \tag{C4}$$

$$POILS_t(\alpha) = \frac{\alpha}{1-(1-\alpha)^{T+1}} \sum_{j=0}^{T} (1-\alpha)^j POIL_{t-j}. \tag{C5}$$

The occurrence of the correction term $\frac{1}{1-(1-\alpha)^{T+1}}$ in (C4) and (C5) ensures that the sum of the weights is equal to one.

Note that the elasticity of the rig rate with respect to the gas and oil price j months ago is given by

$$\frac{\partial \log(RIGRATE)_t}{\partial \log(PGAS_{t-j})} = \beta_1 \left(\frac{\partial PCES_t}{\partial PGASS_t} \frac{PGASS_t}{PCES_t} \right) \left(\frac{\partial PGASS_t}{\partial PGAS_{t-j}} \frac{PGAS_{t-j}}{PGASS_t} \right), \tag{C6}$$

$$\frac{\partial \log(RIGRATE)_t}{\partial \log(POILS_{t-j})} = \beta_1 \left(\frac{\partial PCES_t}{\partial POILS_t} \frac{POILS_t}{PCES_t} \right) \left(\frac{\partial POILS_t}{\partial POIL_{t-j}} \frac{POIL_{t-j}}{POILS_t} \right). \tag{C7}$$

The elasticities in the last parentheses of (C6) and (C7) are given as

$$\frac{\partial PGASS_t}{\partial PGAS_{t-j}} \frac{PGAS_{t-j}}{PGASS_t} = \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\alpha)^j \frac{PGAS_{t-j}}{PGASS_t}, \tag{C8}$$

$$\frac{\partial POILS_t}{\partial POIL_{t-j}} \frac{POIL_{t-j}}{POILS_t} = \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\alpha)^j \frac{POIL_{t-j}}{POILS_t}. \tag{C9}$$

Furthermore, the elasticities in the first parentheses of (C6) and (C7) are given as

$$\frac{\partial PCES_t}{\partial PGASS_t} \frac{PGASS_t}{PCES_t} = \delta \left(\frac{PGASSI_t}{PCES_t} \right)^{1-\sigma}, \tag{C10}$$

$$\frac{\partial PCES_t}{\partial POILS_t} \frac{POILS_t}{PCES_t} = (1-\delta) \left(\frac{POILSI_t}{PCES_t} \right)^{1-\sigma}. \tag{C11}$$

Hence, it follows that

$$\frac{\partial PCES_t}{\partial PGAS_{t-j}} \frac{PGAS_{t-j}}{PCES_t} = \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\alpha)^j \, \delta \frac{PGAS_{t-j}}{PGASS_t} \left(\frac{PGASSI_t}{PCES_t} \right)^{1-\sigma}, \tag{C12}$$

$$\frac{\partial PCES_t}{\partial POIL_{t-j}} \frac{POIL_{t-j}}{PCES_t} = \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\alpha)^j \frac{POIL_{t-j}}{POILS_t} (1-\delta) \left(\frac{POILSI_t}{PCES_t} \right)^{1-\sigma}. \tag{C13}$$

It follows that the two immediate rig elasticities are given by

$$E_{Gas}^{0} = \frac{\partial \log(RIGRATE_t)}{\partial \log(PGAS_t)} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} \delta \frac{PGAS_t}{PGASS_t} \left(\frac{PGASSI_t}{PCES_t} \right)^{1-\sigma}, \qquad \text{(C14)}$$

$$E_{Oil}^{0} = \frac{\partial \log(RIGRATE_t)}{\partial \log(POIL_t)} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{144}} (1-\delta) \frac{POIL_t}{POILS_t} \left(\frac{POILSI_t}{PCES_t} \right)^{1-\sigma}.$$

(C15)

The corresponding medium- and long-term gas and oil price elasticities associated with permanent price changes are furthermore

$$E_{Gas,t}^{T^*} = \sum_{j=0}^{T^*} \frac{\partial \log(RIGRATE_t)}{\partial \log(PGAS_{t-j})} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} \delta \left(\frac{PGASSI_t}{PCES_t} \right)^{1-\sigma} \sum_{j=0}^{T^*} \left(1-\alpha\right)^j \frac{PGAS_{t-j}}{PGASS_t}, \qquad \text{(C16)}$$

$$E_{Oil,t}^{T^*} = \sum_{j=0}^{T^*} \frac{\partial \log(RIGRATE_t)}{\partial \log(POIL_{t-j})} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\delta) \left(\frac{POILSI_t}{PCES_t} \right)^{1-\sigma} \sum_{j=0}^{T^*} \left(1-\alpha\right)^j \frac{POIL_{t-j}}{POILS_t},$$

(C17)

for $1 \le T^* \le T$.

Generally, all the elasticities depend on different price ratios. If one assumes a hypothetical situation such that the prices have been constant over a considerable amount of time, however, one obtains simplified formulae that do not involve the value of the price ratios since they all will be equal to one

$$E_{Gas}^{0} = \frac{\partial \log(RIGRATE_t)}{\partial \log(PGAS_t)} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} \delta,$$

(C18)

$$E_{Oil}^{0} = \frac{\partial \log(RIGRATE_t)}{\partial \log(POIL_t)} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\delta), \tag{C19}$$

$$E_{Gas}^{T^*} = \sum_{j=0}^{T^*} \frac{\partial \log(RIGRATE_t)}{\partial \log(PGAS_{t-j})} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} \delta \sum_{j=0}^{T^*} \left(1-\alpha\right)^j, \tag{C20}$$

$$E_{Oil}^{T^*} = \sum_{j=0}^{T^*} \frac{\partial \log(RIGRATE_t)}{\partial \log(POIL_{t-j})} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\delta) \sum_{j=0}^{T^*} \left(1-\alpha\right)^j, \tag{C21}$$

for $1 \leq T^* \leq T$. Note that when $T^* = T$ one obtains a further simplification to

$$E_{Gas}^{T} = \sum_{j=0}^{T} \frac{\partial \log(RIGRATE_t)}{\partial \log(PGAS_{t-j})} = \beta_1 \delta, \tag{C22}$$

$$E_{Oil}^{T^*} = \sum_{j=0}^{T^*} \frac{\partial \log(RIGRATE_t)}{\partial \log(POIL_{t-j})} = \beta_1 (1-\delta). \tag{C23}$$