Understanding rig rates[1]

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Abstract:

We examine the largest cost component in offshore development projects, drilling rates, which have been high over the last years. To our knowledge, rig rates have not been analysed empirically before in the economic literature. By econometric analysis we examine the effects on Gulf of Mexico rig rates of gas and oil prices, rig capacity utilization, contract length and lead time, and rig specific characteristics. 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. The non-linearity is due to representing the effects of gas and oil prices by a CES price aggregate. Such a model belongs to the class of non-linear mixed models which has been heavily utilized within the biological sciences.

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1. Introduction

High oil and gas prices over several years have been followed by increasing rates of renting oil and gas rigs. Drilling rates in the Gulf of Mexico (GoM) doubled in real prices from the period 2000-2004 to the period 2006-2008, cf. Figure 1. Then the rates fell dramatically in 2009 due to the financial crisis, but have since recovered. High capacity utilization (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 cost and petroleum revenue has risen dramatically. From 1970 to 2005, total annual drilling costs in the U.S. never exceeded 35 per cent of total oil and gas revenues. In the years 2007-2010, the ratio has been between 80 and 90 per cent each year, see Figure 2.

Figure 1: Rig rates and capacity utilization rates for jackups in Gulf of Mexico (GoM) from 1991 to 2009. Monthly unweighted average of rig rates in real prices (1,000 $$_{2008}$ per day)

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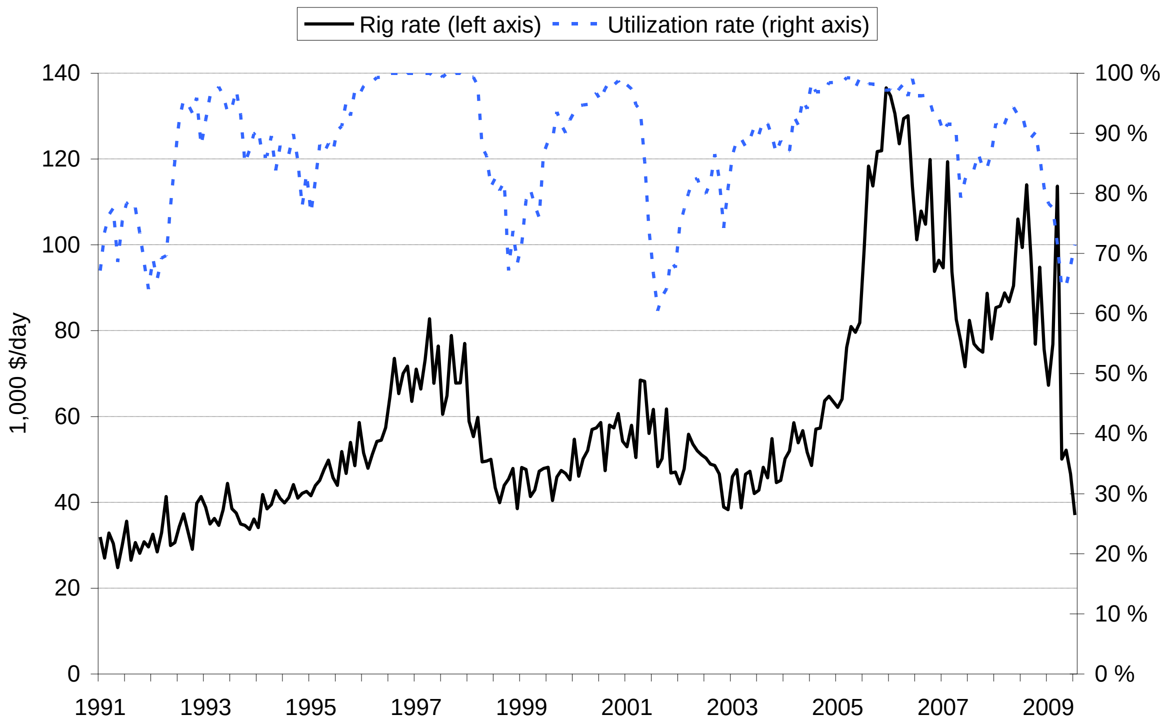
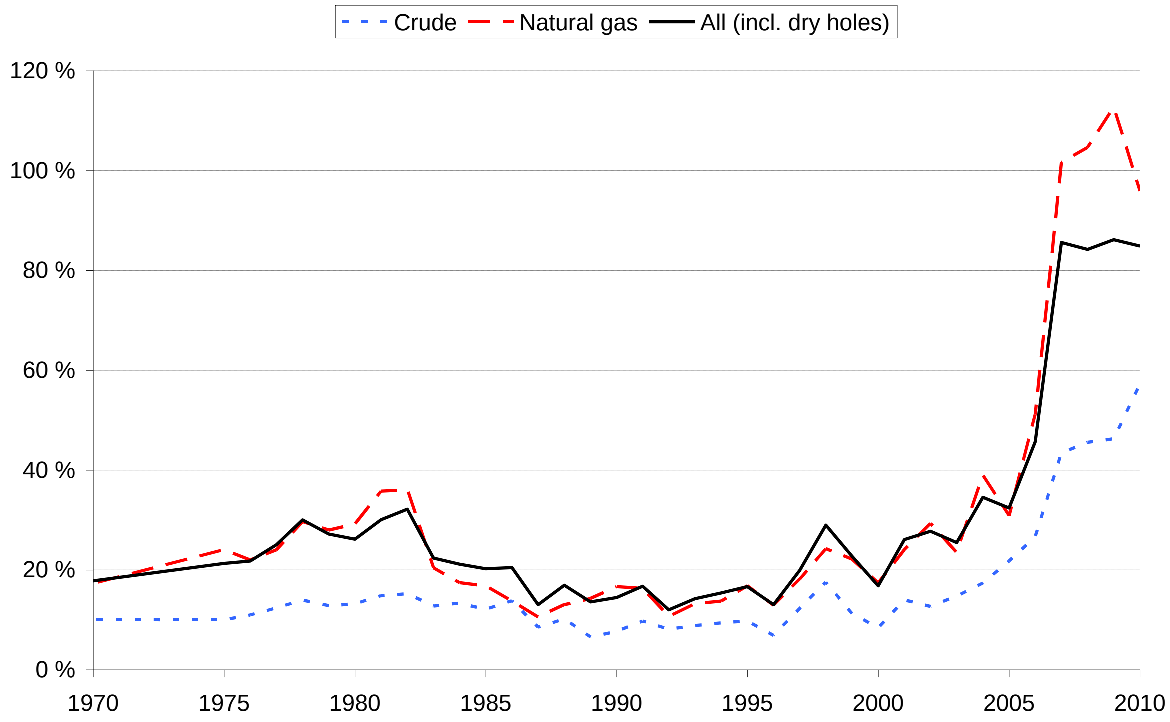


Note: Capacity utilization rates for active rigs

Source: RS Platou

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



Source: EIA (2011)

The cost increase in drilling, which has been seen worldwide over the last years, is likely to have implications for gas and oil prices. It is therefore important to understand the crucial drivers for rig rates. This is the topic of the current paper where we undertake econometric analyses of panel data for jackups in the Gulf of Mexico (GoM). Jackups are rigs used on shallow water that reach to the ocean floor to support the drilling deck.

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

Drilling activities, however, 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 U.S. 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 contracting relationship between oil companies and drilling companies.

In our paper we analyse a unique dataset from the international offshore broker RS Platou that contains contract information and technical data for the rigs in GoM, in particular rig rates and contract length and lead time. GoM is a reasonable well defined submarket for jackups due to moving costs and difficulties of restaffing (Corts, 2008).

When oil and gas companies contract for drilling rigs, they primarily use short-term well-to-well contracts that are 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 do drilling companies (Kellogg, 2011).

Rig rates are volatile, following a clear cyclical pattern. Not surprisingly, rig rates are highly sensitive to gas and oil prices and capacity utilitization. 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 like 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 over rig rates. The relative bargaining power of rig owners and oil companies are likely to have impact on the level of rig rates. Thus, factors that affect relative bargaining power of the contracting parties form our ex ante hypotheses on rig rate formation.

Obviously, high current capacity utilization 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 stimulates rig demand. However, jackup rigs are rented in a contract market, and thus contract length and lead times also play a significant role. In periods of high demand rig owners can demand longer contracts and together with increased lead times this reflect a strong future market. This enhances the bargaining power of the rig companies and 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 is due to representing the effects of gas and oil prices through a CES price aggregate. Our model can be considered a member of the socalled nonlinear mixed effects type of models in the statistical literature (cf. e.g. Vonesh and Chinchilli, 1997; Davidian, 2009 and Serroyen et al., 2009). Such models have been heavily utilized in the biological sciences, but have, to our knowledge, not previously been utilized 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 has 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 utilization, but also contract length and lead time positively affect rig rates. High capacity utilization occurs in periods with high gas and oil prices, i.e., higher gas and oil prices may not only have a direct effect on rig rates, but also an indirect effect via increasing the utilization rate. Rig rates only partly respond to a sudden shift in the gas and oil prices – oil and gas companies wait for some more 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 the rig rates, consistent with the fact that jackups in the GoM area are mostly used for gas drilling. 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, e.g., developing a gas field or an oil field, only one of these prices may be of importance, whereas for other projects such as exploration 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). Their 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} denotes the first and second derivative of B with respect to x, and x and y, respectively).[2] The benefit function is concave in r because the company prioritizes the most valuable projects ahead of less valuable projects. Thus, the number of rigs they rent is given by:

$$B_r(p^G, p^O, r) = \pi \qquad (1)$$

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 a market with monopolistic competition. Although we do not specify a complete model with heterogeneous products, we assume that each rig company has some market power. 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. Further, 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 e.g. to the fact that a rig that is not rented out today may be rented out tomorrow, whereas a rig that is 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:

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[2] Strictly speaking, it is the *expected* net benefits that matter here. However, as the purpose of this theoretical section is to motivate the empirical model, we omit expectations here. Below we return to the question of how price expectations are formed.

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

or:

$$\pi_r^i(p^G, p^O, u^iR^i)u^iR^i + \pi^i(p^G, p^O, u^iR^i) = c_r(u^i)\ , \qquad (2)$$

where $u = r^i/R^i$ denotes the utilization 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 utilization rate in the rig market? It seems reasonable to argue that the monopolistic competition depends on the number of available rigs in the market. Thus, if the utilization rate is high, each rig company will have more market power as the inverse demand function it faces becomes steeper (fewer available substitutes, i.e., rigs). Assuming that the utilization rate in period t+1 is correlated with the utilization rate in period t, it also seems reasonable to assume that the alternative cost of renting out rigs depends on the aggregate utilization 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

$$\pi_r^i(p^G, p^O, u^iR^i, u)u^iR^i + \pi^i(p^G, p^O, u^iR^i, u) = c_r(u^i, u)\ . \qquad (3)$$

A steeper inverse demand function implies in general that the marginal revenue falls. Hence, this tends to reduce r^i (or u^i) and increase π^i. Thus, if some shock (e.g., 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 (as 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 utilization 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 (cf., e.g., Aune et al., 2010). That is, expected prices *t* periods into the future are assumed to depend on current and past prices. The weighing of current vs. past prices is not clear, however, 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 horizon of exploratory drilling and that of drilling additional wells in a developed field. We will use price indexes for gas and oil that are weighted sums of the current prices and the price indexes in the previous period, and leave it up to the estimations to determine the relative weights. The price indexes, which we will refer to as smoothed prices, are specified in the next section.

Although some companies specialize 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 is 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 transportation. A common way of modeling imperfect substitutes is to use a CES (constant elasticity of substitution) 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 limit when the elasticity goes towards infinity, the benefits of gas and oil are fully separable.

Given the CES structure, we can further construct a price index for the CES aggregate, see the next section. Above we argued that the rig rate is increasing in the 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 at the same time assumes 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 variables (e.g., rig categories) or ordinary variables (e.g., technical depth). The contract structure is vital to rig rate determination. Our unique data set has 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, cf. Vonesh and Chinchilli (1997) and Davidian (2008). We consider the following econometric relation

$$\log(RIGRATE_{is}) = \beta_0 + \beta_1 \times \log(PCES_{is}(\alpha_{gas}, \alpha_{oil}, \delta, \sigma)) + \beta_2 \times \log(1 - UTIL_{is}) \times (1 - HIGHUTIL_{is}) +$$
$$\beta_3 \times HIGHUTIL_{is} + \beta_4 \times LEAD_{is} + \beta_5 \times CONT_{is} + \beta_6 \times BUILD_i + \beta_7 \log(DEPTH_i) +$$
$$\sum_{m=2}^{4} \gamma_m \times DUMCATm_i + \sum_{j=1991}^{2009} \lambda_j \times DUMj_{is} + \mu_i + \varepsilon_{is}. \tag{5}$$

The individual rigs have status as observational units. They are denoted by subscripts i (rig number), whereas the subscript s denotes observation number.[3] Most of the variables in (5) are both rig and contract specific, and thus have both subscripts. This also includes the CES price aggregate, as s denotes the observation number and not time. However, if for two rigs observation number s is from the same period, 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 utilization rate lagged one month (relative to when the contract is signed). The variable $HIGHUTIL_{is}$ equals 1 if observation number s from observational unit i corresponds to a period where the capacity utilization is higher than or equal to 0.98, otherwise it is zero. Thus, according to (5) the response to capacity utilization is represented by the log of spare capacity, $\log(1\text{-}UTIL_{is})$, when the capacity utilization is below 0.98, and by $HIGHUTIL_{is}$ when the capacity utilization exceeds or is equal to 0.98. This distinction is based on information from the rig industry, cf. Section 2.[4]

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[3] A 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 given period of time.

[4] Note that specification (5) implies that $\frac{\partial \log(RIGRATE)}{\partial \log(UTIL)} = \frac{-\beta_2 \times UTIL}{1 - UTIL}$ for capacity utilization below 98%, which implies that the elasticity of the rig rate with respect to the capacity utilization rate is higher the higher is the capacity utilization

The next four variables are, respectively, $LEAD_{is}$, $CONT_{is}$, $BUILD_i$ and log$(DEPTH_i)$. 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 building 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.[5] 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 the 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 $\sigma^2_{\mu\mu}$, and ε_{is} denotes a genuine error term. We assume that the genuine errors are normally distributed white noise errors with variance given by $\sigma^2_{\varepsilon\varepsilon}$.

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

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, cf. Koyck (1954):

$$PGASS_{is}(\alpha_{gas}) = \alpha_{gas} \sum_{j=0}^{T} (1-\alpha_{gas})^j PGAS_{t(s)-j}. \tag{6}$$

$$POILS_{is}(\alpha_{oil}) = \alpha_{oil} \sum_{j=0}^{T} (1-\alpha_{oil})^j POIL_{t(s)-j}, \tag{7}$$

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rate. An additional reason for representing the effect of a high capacity utilization rate by a dummy variable is that for some periods the capacity utilization rate equals 1, and in this case log(1-*UTIL*) is not defined.

[5] 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 firm sea floor, while mat supported jackups are used on soft floor. Cantilever jackups are now more common than slot jackups. For more information, see e.g. http://www.rigzone.com/training/insight.asp?insight_id=339&c_id=24.

where $PGAS_t$ and $POIL_t$ are the real prices of gas and oil in period t. 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 rather similar compared to the ones we obtain here.[6] The two smoothed variables defined in (6) and (7) enter as arguments in the CES price aggregate after having been converted to price indices.[7] The two indices are labeled $PGASSI_{is}(\alpha_{gas})$ and $POILSI_{is}(\alpha_{oil})$, respectively. Thus, the CES price aggregate is given by (cf. Equation (4)):

$$PCES_{is}(\alpha_{gas},\alpha_{oil},\delta,\sigma)=\left[\delta\left(PGASSI_{is}(\alpha_{gas})\right)^{1-\sigma}+(1-\delta)\left(POILSI_{is}(\alpha_{oil})\right)^{1-\sigma}\right]^{\frac{1}{1-\sigma}}. \tag{8}$$

Note that the CES price aggregate is a function of four unknown parameters, i.e., 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 (8) 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 maximization we make use of a grid search involving the parameters α_{gas}, α_{oil}, δ and σ. Note that when these parameters are known, Eq. (5) 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 2717 different model specifications. In Table B1 in Appendix B we list the parameter values employed in the grid search. The parameters estimates of the model with the highest log-likelihood values are used in the final maximum likelihood estimation in which all parameters are treated symmetrically.[8]

We also consider model specifications which deviate somewhat from the one specified in Equation (5). In particular, we sometimes omit the capacity utilization variables. The purpose of this is to examine the total effect, i.e., both the direct and the indirect effects, of an increase in the gas and oil price index when capacity utilization is allowed to respond to the price change. The indirect effect is

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[6] 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.

[7] The smoothed prices of gas and oil are converted to indices by diving by the value of the smoothed prices in the first period, that is, 1990M2.

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

when an increase in gas and oil prices stimulates rig rates via the increased capacity utilitization. We would expect the rig rates to respond stronger to price changes in this case compared to what is the case for the main model (cf. the theory discussion in Section 2).

4. Data

The observational units in this paper are jackup rigs in the Gulf of Mexico (GoM). The main data source is provided by the company RS Platou, see Table 1. Altogether we use data for 204 jackups. In the dataset there are four different jackup categories (see footnote 5).[9] The dependent variable in our analysis is rig rate. A rig is rented for a certain period of time according to a contract between the rig company and the petroleum license represented by the operator. We have information about the fixture date, i.e., the date when the contract is signed, as well as starting date and end date for each contract. From the 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 the rig rates by a producer price index to obtain rig rates in constant prices.

The data is on a monthly basis and the timing refers to the point in time when the contract was signed.[10] We have data for the rigs over a substantial amount of time, and hence we have information on different contracts for a specific rig.[11] Thus the data set is 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 U.S. wellhead prices taken from the EIA, whereas for the oil price we use the WTI price. These prices are deflated by the same price index as for rig rates.

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

[10] As mentioned above, we have information about both fixture date, start date and end date for each contract. One problem with the data, however, is that the fixture date often is reported to be after the start date. The reason is that the reported fixture date is when the contract is officially announced, which often is after the handshake date. We then follow the assumptions made by RS Platou which is to set the fixture date to 50 days before the start date of the contract whenever the former comes after the latter in the data.

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

The data from RS Platou also provide information on capacity utilization of jackups in the GoM area. The data material distinguishes between the capacity utilization rates for active rigs and for all rigs. Based on discussions with rig analysts, for our purpose we use the former in our analysis.[12] As the capacity utilization rate 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 utilization rate should not enter linearly in the model – for example, it seems probable that rig rates are more sensitive to increases in capacity utilization rates when these rates are high (i.e., a convex relationship could be expected). This is captured by our model specification for utilization 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 the rig is involved in a specific drilling project. A variable representing this delay is an independent variable in our analysis (*LEAD*). Since the owner of the rig may make different contracts for the same rig for disjunct 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 utilized in the current analysis. The total number of observations is 6,801. The capacity utilization rate shows considerable variation over the sample period.

Table 1. Data sources and unit of measurement

Variable	Variable name	Source	Unit of measurement
Rig rates in current prices	*RIGRATE*	RS Platou	$/per day
Gas price in current prices (U.S. Wellhead price)	*PGAS*	EIA	$/Tcf
Oil price in current prices (WTI)	*POIL*	Petroleum Intelligence Weekly	$/barrel
Deflator for rig rates and oil		U.S. Bureau of Labor	Index variable

[12] For an interesting analysis of the decision of drilling companies to idle ("stack") rigs in periods of low dayrates, see Corts (2008).

price		Statistics	
Capacity utilization rates (for jackups in GoM)	*UTIL*	RS Platou	Ratio
Leadtime	*LEAD*	RS Platou	Number of days
Contract length	*CONT*	RS Platou	Number of days
Build year	*BUILD*	RS Platou	Year
Technical depth	*DEPTH*	RS Platou	Feet
Dummies for rig type	*DUMCATm*[a]	RS 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.

5. Estimation results

Estimation results for our most general model, with separate smoothing parameters for gas and oil prices, are reported in the left part of Table 3. In the right part of the table we report results for a constrained model in which we have omitted the two variables representing the capacity utilization (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 utilization variables included. The value of the LR-statistic is then equal to -2×(227.681-228.864)=2.366 (cf. the left hand parts of Table 4 and Table 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 utilization variables is 0.823 (cf. the log likelihood values in the right hand part of Table 4 and Table 3, respectively). Thus in both cases we do not obtain rejection of the hypothesis using conventional significance values. Hence in the following we will concentrate 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 utilization variables in the left hand part of Table 4.

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

	Model with capacity utilization variables		Model without capacity utilization variables	
Parameters/Explanatory variables	Estimate	t-value	Estimate	t-value
Smoothing parameter gas (α_{gas})	0.055	5.93	0.098	7.61
Smoothing parameter gas (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	
Number of observations	6,801		6,801	
Number of observational units	204		204	

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

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 here refer 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 only partly will respond to a sudden shift in the gas and oil prices – they will wait for some more 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 0.763. Hence, gas prices are much more important than oil prices for changes in the 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 as jackups may be used for both gas and oil drilling.

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. As the estimate is 1.234, this means that a 10% permanent increase in the gas and oil price index increases the rig rates by 12.3%. That is, assuming that other variables in this model – in particular capacity utilization – stay unchanged.

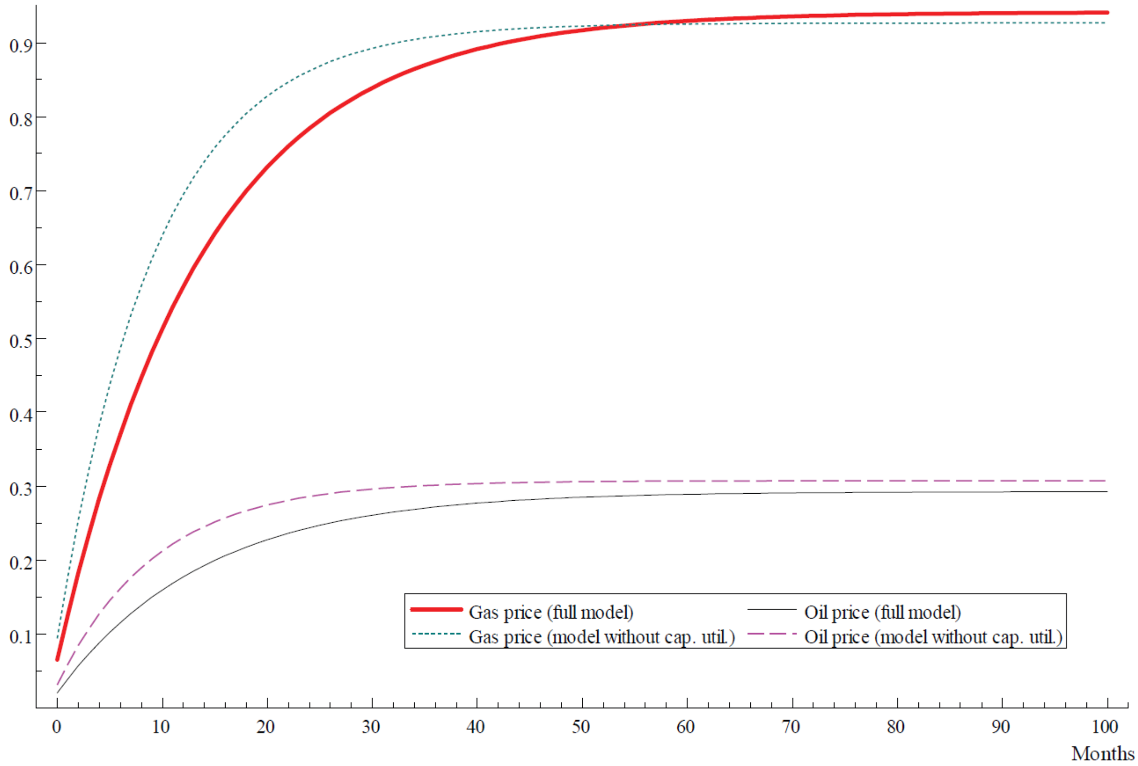
It is relevant to look at immediate, medium-term and long-term price elasticities with respect to gas and oil prices, i.e., how does the rig rate respond to changes in the gas and oil price over time. In Appendix C we have derived the necessary formulae. Under some simplified assumptions we show that the immediate gas and oil price elasticities are given by, respectively, formulae (C18) and (C19). 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 (i.e., with capacity utilization 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. Already after 9 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; cf. the formulae in Appendix C referred to above. The results of using the model without capacity utilization variables are discussed below.

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

	Model with capacity utilization variables		Model without capacity utilization 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*]×(*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	

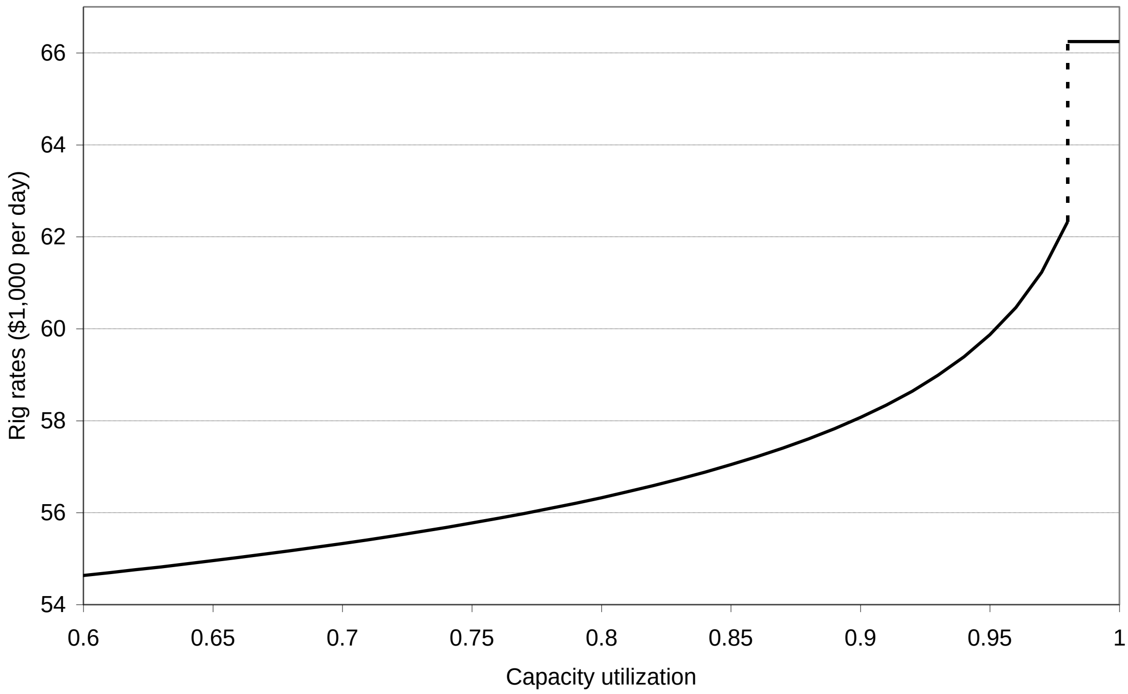
[a] A ^ above a parameter denotes the estimate of the parameter.

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



Next, we see from Table 4 that the effect of capacity utilization is also highly significant. The estimated parameter value suggests that if the share of non-contracted rigs is reduced by 10%, e.g., by increasing the capacity utilization from 90% to 91%, the rig rates increase by 1.6%. This is illustrated in Figure 4, where we show the impacts on the rig rates when capacity utilization is changed, given the estimation results (the figure is constructed around the point where the capacity utilization and the rig rate both equal their mean values, cf. Table 2). We see from the figure that the rig rates typically will increase by 20 per cent if the capacity utilization increases from 60% (lowest observed value) to above 98%, that is, if other variables stay constant. A typical situation, however, is that high capacity utilization occurs in periods with high gas and oil prices, cf. 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 increasing the utilization rate, at least in the short to medium term.

Figure 4. Effects of capacity utilization on rig rates. $1,000 per day



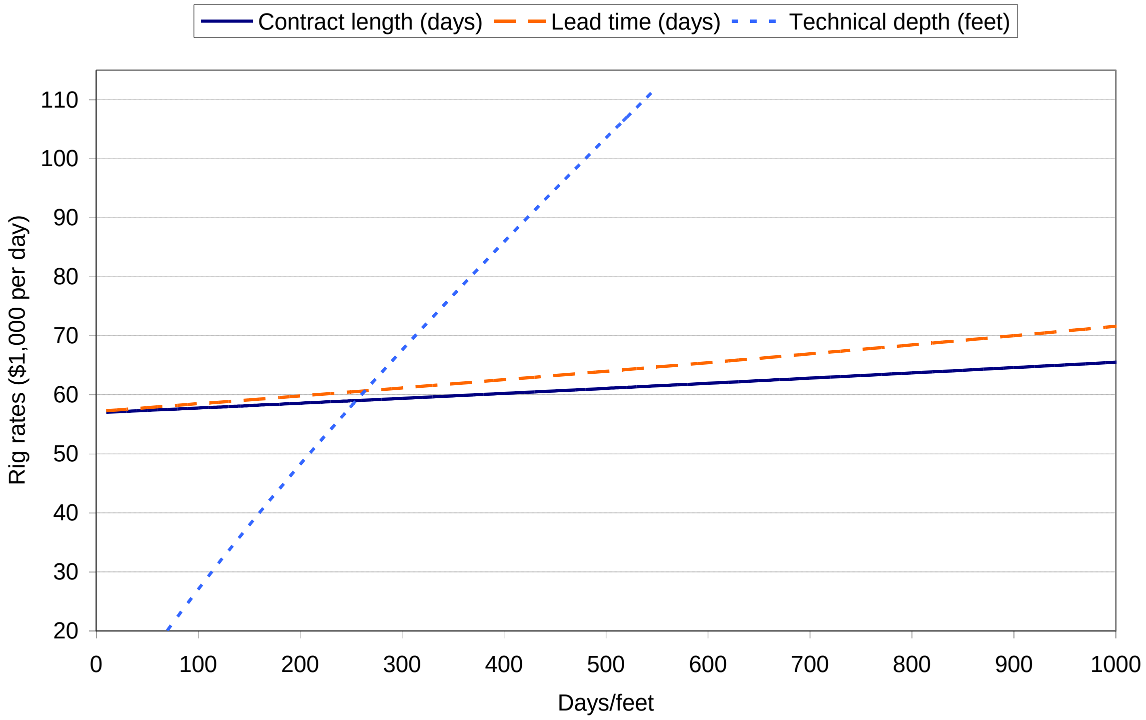
Thus, it is of interest to estimate a model where capacity utilization is excluded, to examine the full effects of an increase in gas and oil prices. The estimation results of such a model are presented in the right hand part of Table 4. Based on the reasoning above, we should expect the short- (and 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 one 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 is carried out 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 utilization variables are forced to be zero. Thus, undoubtedly, capacity utilization is 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, i.e., with and without capacity utilization as a variable.

In particular, we notice that rigs that can drill at larger depths are significantly more expensive than rigs that only can operate on more shallow seas. 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 further show that rigs that are built more recently are more expensive than older rigs – the estimation results indicate that ten years difference amounts to 7% change in the rig rates. According to our industry panel this is due to advances in technology and rig design – new rigs have higher capacity and more functions than elder rigs.

Figure 5 further shows that both the length of the contract and the lead time, i.e., 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 and the operators are being forced to sign contracts in advance. The rig companies' contract backlog increases and thus their relative bargaining power is enhanced and rig rates increase. The estimated value indicates that when the lead time increases by six months, the day rate increases by around 3.8%. We find similarly that increasing the contract length by six months increases the day rate by around 2.6% according to these estimations (see Figure 5). In periods of high demand rig owners can demand longer contracts and together with increased lead times this reflect a strong future market.

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



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

Some but not all of the rig category dummies are significant.[13] The most valuable jackup category according to our results seems to be the *Independent leg slot jackup*, when controlling for other characteristics such as drilling depth and building 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, as 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, cf. Table 2).[14]

6. Conclusions

The relative bargaining power of rig owners and oil companies are likely to have impact on the level of rig rates. Thus, factors that affect 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 utilization in the rig industry is crucial to the bargaining power of the rig companies, and leads to high rig rates. The same applies to a high expected gas and oil prices, which stimulates gas and oil development projects and hence increases rig demand. Consistent with industry practice, however, petroleum companies only partly respond to a sudden shift in the gas and oil prices – they wait for some more months to see if the price change is more permanent. Consistent with the fact that jackups in the GoM area are mostly used for gas drilling, we find that gas prices are much more important than oil prices for changes in the rig rates.

Being a contract market, contract length and lead times also play a significant role. In periods of high demand rig owners can demand longer contracts and together with increased lead times this reflect a

[13] Whereas the log likelihood value is 227.681 (cf. 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.

[14] 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.

strong future market. The increase in the contract backlog enhances the bargaining power of the rig companies and lead to an increase 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 utilized within the biological sciences. Even though they are relevant for several economic applications, too, we are not aware of earlier econometric studies utilizing such models.

In our estimations we have implicitly treated the GoM area as a closed market, as capacity utilization 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 between areas takes place. However, it is quite costly to move rigs over large distances, so 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. It would be interesting to investigate whether the market for renting floaters has similar characteristics as the jackup market. In particular, 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. This question we leave for future research.

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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 utilization rates for jackups in the Golf of Mexico area

Figure A2. The oil price in current US dollars

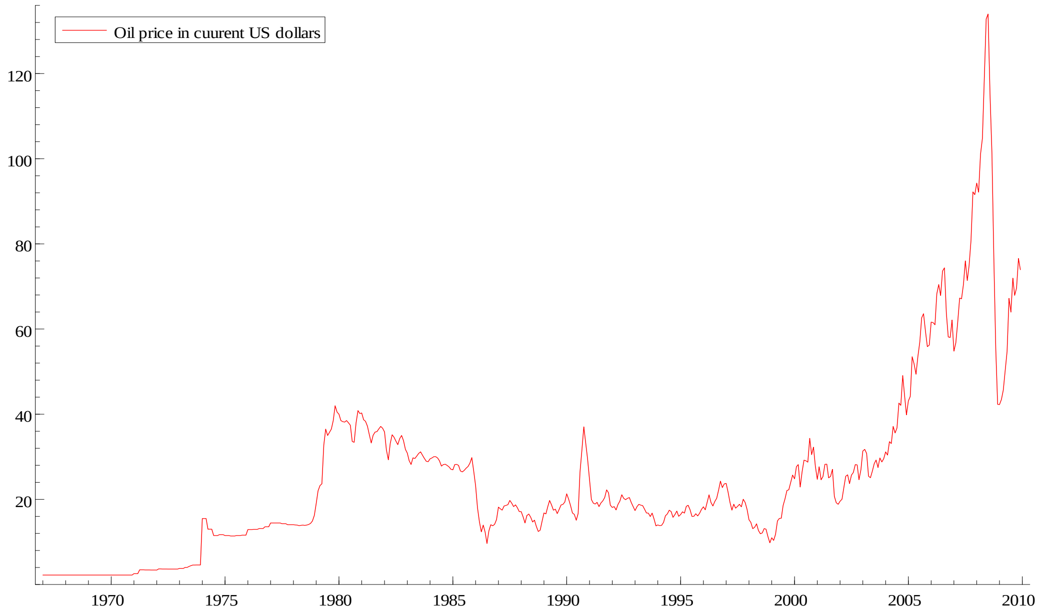


Figure A3. U.S. Natural Gas Wellhead Price (Dollars per Thousand Cubic Feet)

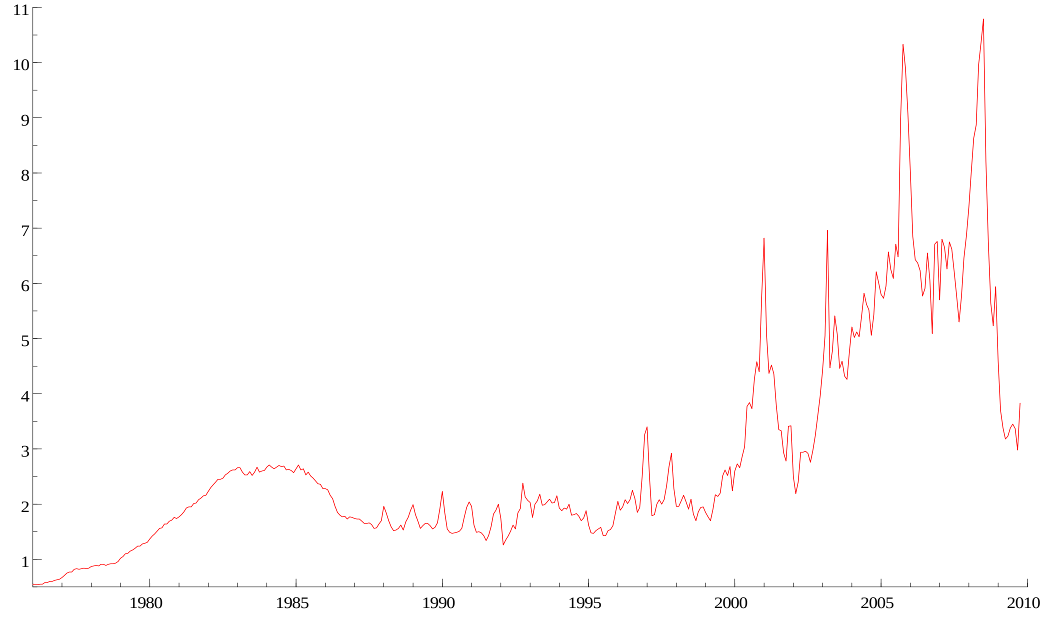
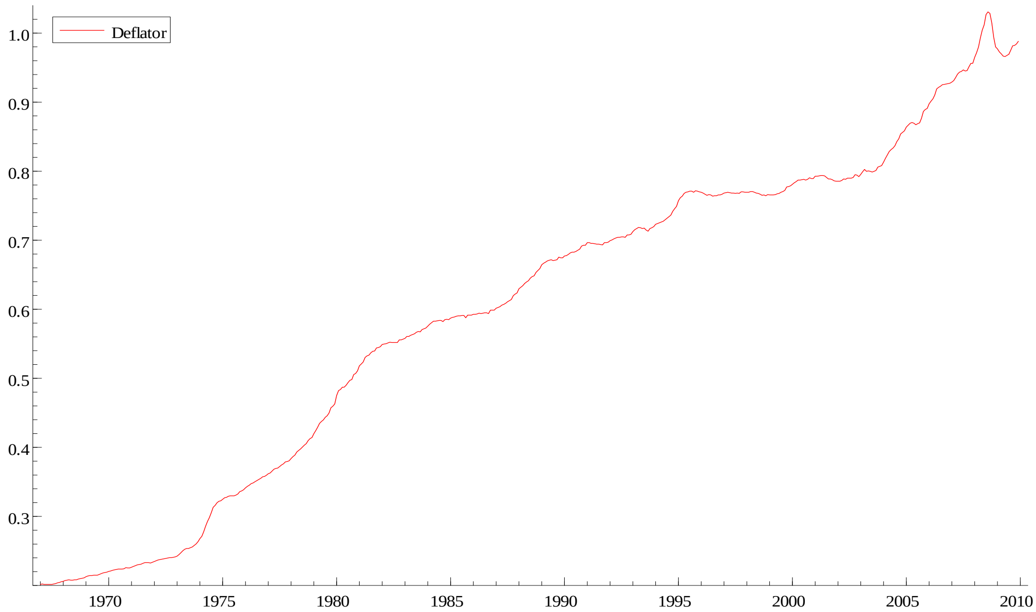


Figure A4. The price deflator – 2008=1



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 rates elasticities with respect to gas and oil prices

Our CES-aggregate of gas and oil prices is given as

$$PCES_t(\alpha,\delta,\sigma) = \left[\delta \left(PGASSI_t(\alpha) \right)^{1-\sigma} + (1-\delta)\left(POILSI_t(\alpha) \right)^{1-\sigma} \right]^{\frac{1}{1-\sigma}}, \tag{C1}$$

where $PGASSI_t(\alpha)$ and $POILSI_t(\alpha)$ are, respectively, indices of smoothed gas and oil prices. 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 occurence 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 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

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

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

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

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

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

It follows that the two immediate rig elasticities are given by

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

$$E^0_{Oil}=\frac{\partial\log(RIGRATE_t)}{\partial\log(POIL_t)}=\beta_1\frac{\alpha}{1-(1-\alpha)^{144}}(1-\delta)\frac{POIL_t}{POILS_t}\left(\frac{POILSI_t}{PCES_t}\right)^{1-\sigma}. \tag{C15}$$

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

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

$$E_{Oil,t}^{T^*} = \sum_{j=0}^{T^*} \frac{\partial \log(RIGRATE_t)}{\partial \log(POIL_{t-j})} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} (1-\delta) \left(\frac{POILSI_t}{PCES_t} \right)^{1-\sigma} \sum_{j=0}^{T^*} (1-\alpha)^j \frac{POIL_{t-j}}{POILS_t}, \quad \text{(C17)}$$

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

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

$$E_{Gas}^0 = \frac{\partial \log(RIGRATE_t)}{\partial \log(PGAS_t)} = \beta_1 \frac{\alpha}{1-(1-\alpha)^{T+1}} \delta, \quad \text{(C18)}$$

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

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

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

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

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

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