Technological Forecasting & Social Change 76 (2009) 339–357

Contents lists available at ScienceDirect

Technological Forecasting & Social Change

Dynamics of the UK natural gas industry: System dynamics modelling and long-term energy policy analysis

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ARTICLE INFO

Article history:
Received 25 November 2007
Received in revised form 6 June 2008
Accepted 8 June 2008

Keywords:
System dynamics
UK natural gas model
Energy policy
Long-term policy analysis
Imports
Energy security

ABSTRACT

We present a dynamic model of the indigenous natural gas industry in the UK. The model has been built using a system dynamics approach. Using the model several scenarios have been analyzed. We found that management of the supply-side policy alone cannot substantially postpone the discovery, production and consumption peak. We also found that the dynamics of the main variables, namely, exploration, production and consumption, are sensitive to initial demand conditions. Postponing the onset of gas price increases can therefore be achieved more effectively through efforts to reduce demand growth. One might expect that a low taxation policy would encourage more exploration and production of gas and thereby stimulate higher consumption rates. Instead, there was no overall net effect on production and consumption in the long term. The depletion effect on cost of exploration acts as counterbalance to low taxation policy. Depletion effect causes cost and thus price to rise further which depress consumption rate. The advances in exploration and production technology can delay the peak of exploration, production and consumption. Technological improvements mean lower cost of exploration and production which pressure down the long-term pattern of price dynamics.

1. Introduction

The UK offshore natural gas and oil industry has a long and successful history and has been said to represent the pride of UK engineering science [1, p. 24]. For over 30 years, the North Sea has provided the UK with a reliable and flexible source of gas that has greatly benefited the UK, but as gas reserves, and consequently production, decline the UK will rely increasingly on imports [2, p.2].

We develop a system dynamics model to investigate the factors influencing the long-term supply and demand of the UK indigenous natural gas and to determine the nature of system behaviour as well as examining the effectiveness of various policies in softening the transition from self-sufficiency to gas import-dependence in the long term.

Insights into some of the basic dynamic behaviours of the natural gas industry were derived from Naill's earlier works on system dynamics energy modelling [3,4, pp. 213–257] and Sterman and Richardson's simulation model of an exhaustible resource [5]. Our model has substantially broadened the representation of the gas industry beyond that found in Naill's model [4]. In particular, we have tried to tackle some of the limitations which in our opinion made Naill's model [4] a less realistic representation given the specific details of the indigenous UK gas production industry.

Firstly, the structure of Naill's model [4] implies that production rate equals usage rate modified by price. We find this assumption to be unrealistic in our case and therefore we explicitly model the production process.

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doi:10.1016/j.techfore.2008.06.002

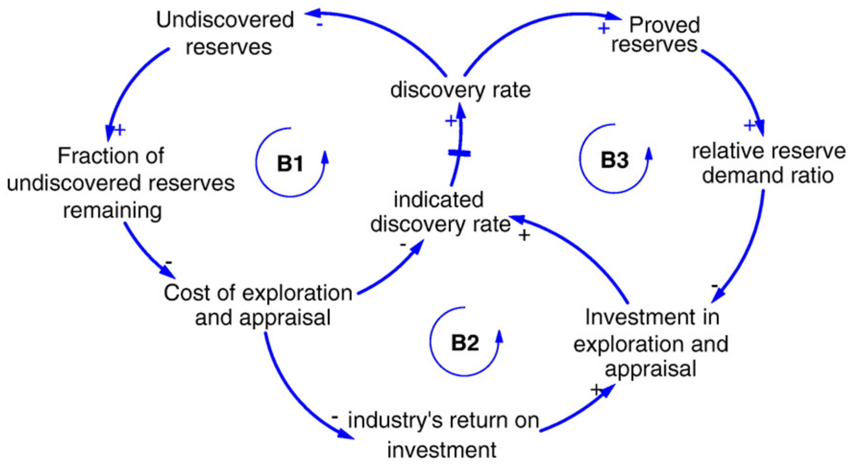

Fig. 1. Causal loop/flow diagram of exploration sector.

Secondly, Naill [4] modelled the potential demand exogenously assuming a constant growth rate. We take an approach similar to Sterman and Richardson, and model the gas demand through substitution effects on one side and exogenous growth of total primary energy demand on the other side.

Thirdly, Naill did not model inter-fuel substitution which is an important issue for long-term energy modelling. Naill suggested that the assumption of independence, particularly between oil and gas, could affect the specific behaviour of the model in the early stages of gas discovery but would not affect overall model behaviour. The justification given for ignoring the oil and gas interdependency was that at that time in the U.S. over 70% of all gas wells were unassociated with oil [6]. Sterman and Richardson did include substitution between gas and oil in their model and we follow the Sterman and Richardson approach and model inter-fuel substitution explicitly.

Lastly, both Naill [4] and Sterman and Richardson [5] have pointed out that the outcome of investment in exploration is generally not known for perhaps 4 to 5 years because of the need to wait for the results of site drilling, accurate resource estimation, etc. Therefore gas producers must inevitably base their exploration-related investment decisions on demand and price projections. However in Naill's [4] model, the determinant of discovery rate is production or usage rate, which represents the current rather than the projected rates. Accordingly, the exploration-related investment decisions in our model are based on information about future demand.

The paper is organised in the following way: in Section 2 the model assumptions are introduced. Section 3 presents the model structure and its general description. In Section 4 the dynamic behaviour of the model and its validation can be found. Section 5 introduces the results of alternative scenarios analysis and Section 6 discusses the major conclusions to be drawn from the model.

2. Model assumptions

Since we are interested in overall system behaviour the model assumes that the UK gas industry has only one firm exploring and producing an undifferentiated product, natural gas. This assumption is similar to that used by Naill [4] and by Sterman and Richardson [5].

The model has a uniform price for natural gas driven by supply–demand conditions, but we will focus here specifically on the wholesale price. By the average wholesale price we mean average wellhead price plus the costs of conveying to the UK beach and the costs of treatment. In reality, there is no single price for natural gas and the gas price issue is very complicated [1]. We are not conducting a detailed investigation into the nature of different gas prices so when we discuss gas price we mean the average wholesale price, which roughly corresponds to the UK OTC wholesale price. The use of the wholesale price as the proxy for the commodity gas price in the UK might be justified since Wright found that there are significant positive correlations in gas prices in the UK [1, pp.101–107].

The model does not consider potential effects of imports or exports on system behaviours. Also the model does not explicitly model technological improvements in exploration or production. However the effects of technological improvements can be analyzed in our model by assuming that unit costs of exploration and production fall over time.

3. Model structure and general description

The model consists of three main parts, the namely exploration sector, the production and consumption sector, and the demand and substitution sector.

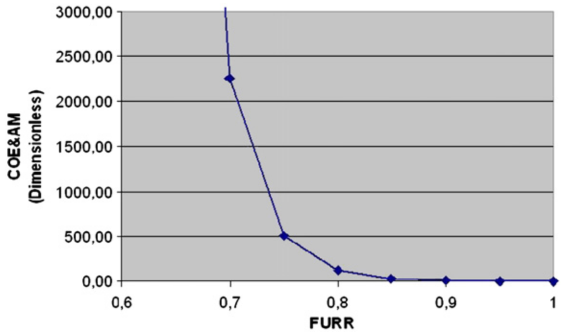

Fig. 2. Relationship between FURR and COE&AM.

3.1. Exploration sector

The exploration sector is mainly represented by three negative feedback (balancing) loops (for details of main loops and their variables see Appendix). These loops represent the relationships between discovery rate, costs, investment and demand (Fig. 1).

Undiscovered reserves (UR) is the total volume of natural gas expected to be found in the future that is not due to growth of existing fields. It assumes current discovery technologies and is not necessarily economically exploited [7]. We follow Hubbert's assumption that the amount of fossil fuels, in our case natural gas, is finite [8]. This assumption is more accurate for a well-explored mature basin such as the UK sector of the North Sea. Proved reserves (PR) are defined as those reserves that have a high confidence of being produced, and by implication, that are already economic. The data for UR and PR were derived from the UK Department of Trade and Industry's (DTI) annual Energy Reports 1998–2001 (The "Brown Book") [9] and the UK energy sector indicators 2006 [10].[1]

The key assumption here is that a fall in the fraction of undiscovered reserves remaining (FURR) will cause the cost of exploration and appraisal (COE&A) drilling to increase [4]. To test this assumption a regression was performed on 1987–1998 data for COE&A drilling and FURR [9]. The regression yielded[2]:

$$\begin{aligned} &Ln\,(\mathrm{COE\&A}) = -21.66 Ln(FURR) - 4.5 \\ &\qquad\qquad\qquad\quad (4.4) \qquad\quad (0.26) \\ &R^2 = .731 \qquad SER = .44 \end{aligned} \tag{1}$$

The relationship between COE&A drilling for additional gas discoveries and depletion of undiscovered gas reserves is reflected in Fig. 2 through the COE&A Multiplier.

The relationship reflects the fact that there are diminishing marginal returns from a gas field. The COE&AM curve was derived from the above relationship (Eq. (1). Eqs. (2) and (3) show how COE&A is calculated.

$$\mathrm{FURR} = \frac{\mathrm{UR}}{\mathrm{IUR}} \tag{2}$$

$$\mathrm{COE\&A} = \mathrm{COE\&AM} \times \mathrm{ICOE\&A} \tag{3}$$

FURR Fraction of Undiscovered Reserves Remaining (dimensionless)
UR Undiscovered Reserves (m^3)
IUR Initial value of Undiscovered Reserves (m^3)
COE&A Cost of exploration and appraisal (GBP/m^3)
COE&AM Cost of exploration and appraisal multiplier (dimensionless)
ICOE&A Initial cost of exploration and appraisal (GBP/m^3)

The data for COE&A drilling is extremely difficult to obtain because of the allocation problem between oil and gas exploration and appraisal (E&A) drilling. The "Brown Book" [9] reported the data on capital investment which included the total cost of exploration and appraisal drilling for oil and gas wells. To derive the cost of gas E&A drilling alone we have calculated the share of successfully drilled gas wells against oil wells. This share gave us an approximation of investment that went on gas E&A. The methodology for calculating COE&A employed in this study is similar to that of Naill [4]. Consequently, the annual amount of gas

[1] Most data on upstream activities in the UK Continental Shelf (UKCS) are available in DTI "Brown Book" versions 1998–2001 which cover data from 1987 until 2001. Since 2001 "Brown Book" is not published anymore. Instead of the "Brown Book" most energy statistics are now published on DTI's official web-site subdivided into several sections. Additional to data from the "Brown Book" other data for our study were derived from DTI Energy Sector Indicators 2006 (the latest available version).

[2] Throughout, the value in parentheses is the standard error. For Eq. (1), T and F statistics for this regression are significant at the 1% level.

discovered (Indicated discovery rate or 'IDR') is equal to the industry's investment in E&A drilling divided by the COE&A in GBP per cubic meter of gas discovered.

$$\mathrm{IDR} = \frac{\mathrm{IE\&A}}{\mathrm{COE\&A}} \tag{4}$$

$$\mathrm{DR} = \mathrm{DELAY}(\mathrm{IDR}, 4.5) \tag{5}$$

IDR	Indicated discovery rate (m^3/year)
IE&A	Investment in exploration and appraisal (GBP/year)
COE&A	Cost of exploration and appraisal (GBP/m^3)
DR	Discovery rate (m^3/year)
DELAY	Delay function
4.5	4.5 years of delay in the results of IE&A drilling [11]

It should be noted that variable discovery rate equals to the value of the indicated discovery rate, but with a delay of 4.5 years. The delay value was taken from Khazzoom [11] who derived the value on the basis of regression analysis of the response of gas discoveries to changes in gas price. His results suggest that the delay between E&A investments and actual discoveries is 4.5 years [11].

Industry's willingness to invest in new exploration activities is assumed to be proportional to its sales revenue. During the industry's growth phase this enables its further expansion through higher rate of investment in new gas discoveries. Like any type of investment decision, the decision to invest in E&A depends on industry's return on investment (ROI, loop B2) and the relative reserve–demand ratio (RRDR, loop B3) [4]. This assumption is consistent with results yielded from regressions[3] (Eqs. (6) and (7)) performed on 1987–1992 data for industry's ROI, RRDR and percentage of sales invested in E&A (PSIE&A) [12,9]. Eqs. (6)–(11) show the results of the regressions and how E&A investment is calculated in our model.

$$\begin{aligned} &Ln\,(\mathrm{PSIE\&A}) = -\underset{(0.14)}{1.04}Ln(RRDR)-\underset{(0.019)}{0.95} \\ &R^2 = .97 \quad SER = .036 \end{aligned} \tag{6}$$

$$\begin{aligned} &Ln\,(\mathrm{PSIE\&A}) = \underset{(0.1)}{0.68}Ln(\mathrm{ROI})-\underset{(0.05)}{1.2} \\ &R^2 = .956 \quad SER = .04 \end{aligned} \tag{7}$$

$$\mathrm{RRDR} = \frac{\mathrm{RDR}}{\mathrm{NRDR}} = \frac{\mathrm{PR}/\mathrm{NGD}}{\mathrm{NRDR}} \tag{8}$$

$$\mathrm{ROI} = \frac{\mathrm{AWP}}{\mathrm{TC}} \tag{9}$$

$$\mathrm{PSIE\&A} = \mathrm{ROIF} \times \mathrm{RRDRF} \times \mathrm{IPSIE\&A} \tag{10}$$

$$\mathrm{IE\&A} = \mathrm{PSIE\&A} \times \mathrm{SR} \tag{11}$$

RDR	Reserve–demand ratio (Years)
PR	Proved reserves (m^3)
NGD	Natural gas demand (m^3/year)
RRDR	Relative reserve–demand ratio (dimensionless)
NRDR	Normal reserve–demand ratio (10 years)
ROI	Industry's return on investment (% per year)
AWP	Average wholesale price (GBP/m^3)
TC	Total cost (GBP/m^3)
PSIE&A	Percentage of sales invested in E&A (% per year)
IPSIE&A	Initial percentage of sales invested in E&A (37% in 1987 [9])
ROIF	ROI Factor (dimensionless)

[3] For Eq. (6): *T* statistic is significant at the 1% level and *F* statistic is significant at the 5% level; For Eq. (7): *T* statistic is significant at the 2.5% level and *F* statistic is significant at the 5% level.

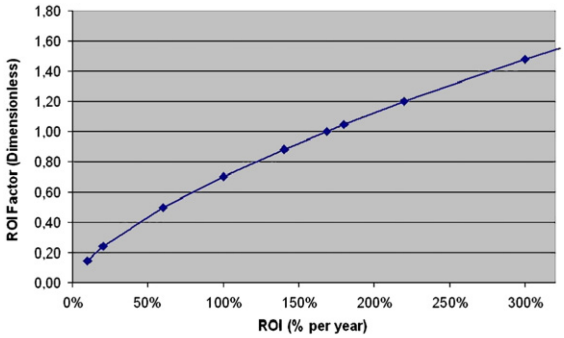

Fig. 3. ROI versus ROI Factor.

RRDRF	RRDR Factor (dimensionless)
IE&A	Investment in exploration and appraisal (GBP/year)
SR	Sales revenue (GBP/year)

Regression results (Eq. (6) show that the relationship between PSIE&A and RRDR is negative. Producers will invest in exploration of new fields only if they expect that demand would exceed some 'normal' level. If the RDR falls below the 'normal' level, which is assumed to be 10 years in our model (based on industry's historical data [12]) producers will invest more to satisfy growing demand. By contrast, a fall in projected demand would cause RDR to exceed the desired level, which in turn discourages investment.

Regressions performed on ROI and PSIE&A data (Eq. (7) yielded a positive coefficient, which verifies our assumption that investment in E&A is driven by dynamics of ROI as well. To incorporate these findings in our model, PSIE&A has been modelled as the product of the ROI Factor and RRDR Factor (Figs. 3 and 4). RRDRF and ROIF curves were derived from Eqs. (6) and (7).

These two mechanisms (Figs. 3 and 4) imply that investment in E&A will be encouraged when (i) the proved reserves are not anticipated to be large enough to cover projected demand and (ii) ROI is high enough; by contrast, these mechanisms discourage investment when (i) proved reserves are much larger than projected demand or (ii) ROI is relatively low.

3.2. Production and consumption sector

The production rate is determined by two main forces: (i) industry's willingness to invest in production (loop B4); and (ii) the consumption rate (loop B5) (see Fig. 5). Basically, the loop B4 represents the supply side (production side). The consumption rate is determined by the price of natural gas and demand (loop B5).

The loop B4 shows that an increase in production rate causes the relative reserve–production ratio (RRPR) to rise and an increase in RRPR causes the Production Unit Cost (PUC) to rise. A rise in the PUC will ensure that the production rate will be lower than it otherwise would have been.

The main assumption of this loop (B4) is that when RPR exceeds its "normal" value, the PUC tends to increase. The production rate from a reservoir can be increased by drilling additional production wells, but well numbers are limited by their cost compared with the extra flow rate [13, p.82]. Another limitation on useful investment in producing wells is the well density i.e. there can be technological limits to the number of producing wells that can be installed for a given field [5, p.11]. The NRPR is assumed to be 12 years, which corresponds to the industry average [13, p.83–84]. Therefore, as production rate increases and proved reserves are depleted, the RPR approaches its normal value, in order to extract more gas additional wells and other facilities will need to be installed. In order to derive a numerical relationship between the depletion of gas reserves and PUC, a regression was performed on

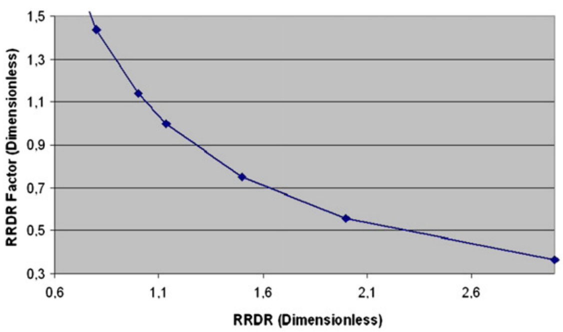

Fig. 4. RRDR versus RRDR Factor.

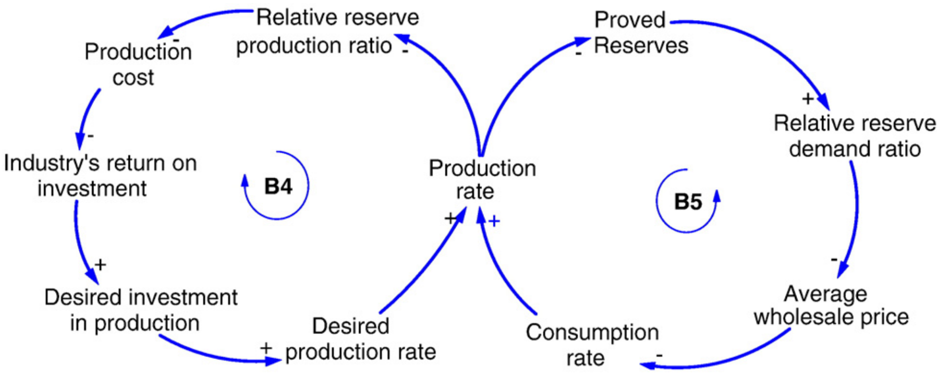

Fig. 5. Causal Loop/Flow Diagram of production and consumption sector.

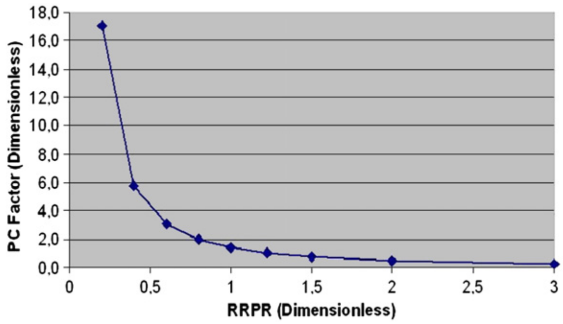

Fig. 6. RRPR versus PC Factor.

1987–2000 data for production cost (PC) and RRPR [12,9]. Eqs. (12)–(14) provide the regression results and indicate how PUC is computed:

$$\begin{aligned} &Ln\,(\mathrm{PC}) = 0.28 - 1.56 Ln(RRPR) \\ &\qquad\qquad (0.036)\ \ (0.134) \\ &R^2 = .92 \quad SER = .11 \end{aligned} \tag{12}$$

$$\mathrm{RRPR} = \frac{\mathrm{RPR}}{\mathrm{NRPR}} = \frac{\mathrm{PR/PRR}}{\mathrm{NRPR}} \tag{13}$$

$$\mathrm{PUC} = \frac{\mathrm{IPC} \times \mathrm{PCF}}{\mathrm{PRR}} \tag{14}$$

RPR	Reserve–production ratio (years)
PR	Proved reserves (m^3)
PRR	Production rate (m^3/year)
RRPR	Relative reserve–production ratio (dimensionless)
NRPR	“Normal” reserve–production ratio (12 years)
PUC	Production unit cost (GBP/m^3)
IPC	Initial production cost (£447 million in 1987)
PCF	Production cost factor (dimensionless)

Based on the results above (Eq. (12) the Production Cost Factor (PCF) curve was derived by normalising its value to 1.0 at the 1987 level of RRDR (1.22). The PCF curve versus RRPR is represented in Fig. 6.

As in the case for E&A investment (loop B2), the model assumes that the percentage of sales revenue invested in production (PSIP) depends on the dynamics of industry's ROI. This assumption is consistent with the results of the regression[4] (Eq. (15) performed on 1987–1994 data for operating expenditures plus other costs related to production expansion and ROI [9].

$$\begin{aligned} &Ln\,(\mathrm{PSIP}) = 0.88 Ln(\mathrm{ROI}) - 1.098 \\ &\qquad\qquad\qquad (0.24) \qquad (0.15) \\ &R^2 = .82 \qquad SER = .1 \end{aligned} \tag{15}$$

[4] For Eq. (15): T statistic and F statistic are significant at the 5% level.

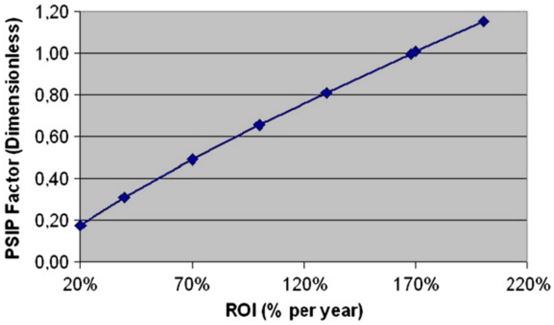

Fig. 7. ROI versus PSIPF.

The relationship between ROI and PSIP Factor (PSIPF) is shown in Fig. 7. The PSIPF curve was derived from Eq. (15) by normalising its value to 1.0 at 1987 levels (168% ROI).

The impact of producers' willingness to expand gas production on the actual production rate is seen in the variable, Desired Production Rate (DPR). This variable represents the producers' desired annual output based on information regarding ROI. The calculation of DPR is shown in Eqs. (16) and (17).

$$\mathrm{DIP} = \mathrm{PSIP} \times (\mathrm{SR}-\mathit{IE\&A}) \tag{16}$$

$$\mathrm{DPR} = \frac{\mathrm{DIP}}{\mathrm{PUC}} \tag{17}$$

DIP	Desired investment in production (GBP/year)
PSIP	Percentage of sales revenue invested in production (% per year)
SR	Sales revenue (GBP/year)
IE&A	Investment in exploration and appraisal (GBP/year)
DPR	Desired production rate (m^3/year)
PUC	Production unit cost (GBP/m^3)

The relationships between reserves, price, consumption and production rate are represented through loop B5. The loop works in the following way: an increase in the production rate depresses proved reserves, which in turn leads to a decrease in RRDR. The decrease in RRDR causes the gas price to rise, which in turn decreases the consumption rate. As a result, the production rate will be lower than it otherwise would have been. The main assumptions of this loop are: (i) the gas price is determined through the variable RRDR and (ii) gas consumption is price sensitive.

The assumption that the price depends on projected demand and availability of gas reserves is consistent with the results of the ILEX report on gas prices in the UK [14, pp.7–15]. ILEX reported that apart from linkages to oil price, gas prices in the UK are driven by demand–supply balancing as well as market sentiment (expectations of market players about future demand/supply). To check the assumption a regression was performed on 1992–1997 data for gas price and RRDR [15,9]. The result of the regression[5] (Eq. (18) confirms our assumption.

$$\begin{aligned} &Ln\,(P) = 0.11-2.03Ln(RRDR) \\ &\qquad\quad (0.03) \qquad\quad (0.34) \\ &R^2 = .9 \qquad SER = .08 \end{aligned} \tag{18}$$

So in our model, the average wholesale price (AWP) of natural gas is determined to be a product of the total cost (TC) and the price factor (PF) which is influenced by the RRDR dynamics (Fig. 8). PF curve was derived from Eq. (18).

Formally, the price was defined as indicated in Eqs. (19)–(21):

$$\mathrm{TUC} = \mathrm{COE\&A} + \mathrm{PUC} \tag{19}$$

$$\mathrm{STC} = \mathrm{SMOOTH3}(\mathrm{TUC}, \mathrm{SD}) \tag{20}$$

$$\mathrm{AWP} = \mathrm{PF} \times \mathrm{STC} \tag{21}$$

PF	Price factor (dimensionless)
AWP	Average wholesale price (GBP/m^3)
TUC	Total unit cost (GBP/m^3)
COE&A	Cost of exploration and appraisal (GBP/m^3)

[5] For Eq. (18): *T* statistic and *F* statistic are significant at the 1% level.

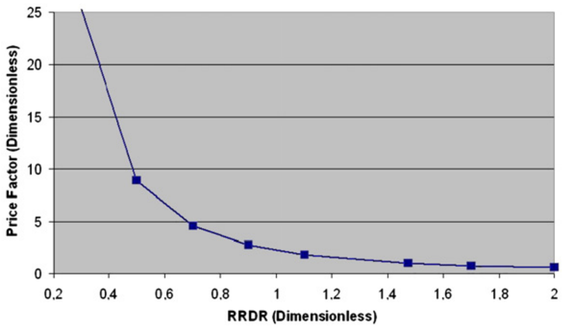

Fig. 8. RRDR versus PF.

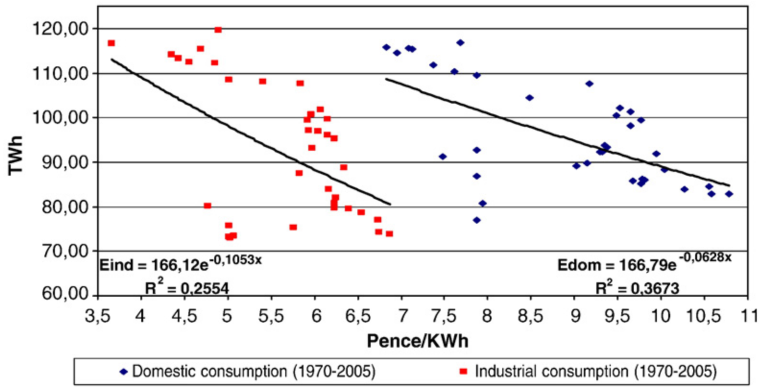

Fig. 9. Electricity price and consumption in the UK 1970–2005. Personal calculations based on [10,15].

PUC Production unit cost (GBP/m^3)
STC Smoothed total cost (GBP/m^3)
SMOOTH3 Third-order exponential smoothing function
SD Smoothing delay (years)

A delay in TC is introduced because of the heterogeneous nature of the costs of gas. At the initial stage of a field's development, gas is produced at lower prices than at later stages (because of the depletion effect on costs) [4, p.224]. The length of the smoothing delay (SD) depends on the magnitude of the discovery and the production rate. New discoveries lead to depletion and hence increase the cost of future discovered gas. To reflect the increase in the cost of that particular amount of discovered gas the delay time should equal the RPR. When new discoveries exceed the production rate, RPR will increase and therefore, the cost of that particular amount of discovered gas will be high only after a period of time indicated by RPR.

The assumption that gas consumption is price sensitive is supported by analysis of long-term electricity consumption and prices in the UK (Fig. 9). In 2005, natural gas contributed 29% of electricity generation in the UK [9]; thus, if the gas price increased electricity generators would be expected to switch to other fuels (e.g. coal). In 2004, coal prices rose relative to gas prices which led to a reduction in the amount of coal consumed. Similarly, the large increases in gas prices in 2005 and 2006 meant that more coal was used for generation than gas [16, p.325].

To validate this assumption a regression was performed on 1987–2005 data for average gas price and consumption rate [12,15]. We included a time variable in the regression to account for other effects on gas consumption, such as income effect. The regression[6] yielded:

$$\begin{aligned} &Ln\,(C) = 2.56 - 0.42Ln(P) + 0.054(t) \\ &\qquad\quad (0.13) \qquad (0.41) \qquad (0.004) \\ &R^2 = .945 \qquad SER = .063 \end{aligned} \tag{22}$$

The regression finds a negative price coefficient and that there is a significant relationship, therefore, we can assume that natural gas consumption is price sensitive. The relationship between gas price and actual consumption can be represented through the Consumption Factor (CF) (Fig. 10).

[6] For Eq. (22): T statistics and F statistic are significant at the 1% level.

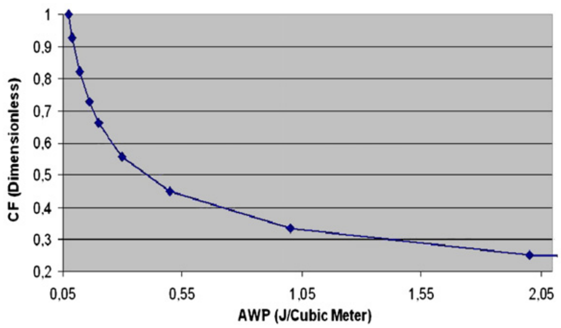

Fig. 10. AWP versus CF.

The CF curve was derived from Eq. (22) by normalising its value to 1.0 at an average gas price of 0.075 GBP/m^3 (the gas price in 2004 [15]). As a result, consumption is computed as follows:

$$\mathrm{CR} = \mathrm{CF} \times \mathrm{NGD} \tag{23}$$

CR Consumption rate (m^3/year)
CF Consumption factor (dimensionless)
NGD Natural gas demand (m^3/year)

Finally, in the production–consumption sector, production should be linked with the actual consumption. Based on information about the actual consumption rate, producers regulate their production capacity in order for their production rate to equal the actual consumption rate. Formally, production rate is computed as:

$$\mathrm{PRR} = min(\mathrm{DPR}, \mathrm{CR}) \tag{24}$$

PRR Production rate (m^3/year)
DPR Desired production rate (m^3/year)
CR Consumption rate (m^3/year)

The combined logic of all the feedback loops in the production–consumption sector is that producer willingness to invest in production is driven by industry's ROI and the actual consumption rate, which is driven by price dynamics.

3.3. Demand projection and substitution sector

The demand and substitution sector has only one balancing loop, B6 (Fig. 11). The loop works as follows: an increase in gas demand causes gas price to increase through RRDR. The increase in gas price leads to a rise in the share of other fuels in total primary energy demand (TPED). The increase in the share of other fuels in TPED closes the loop and ensures that the natural gas demand will be lower than it otherwise would have been.

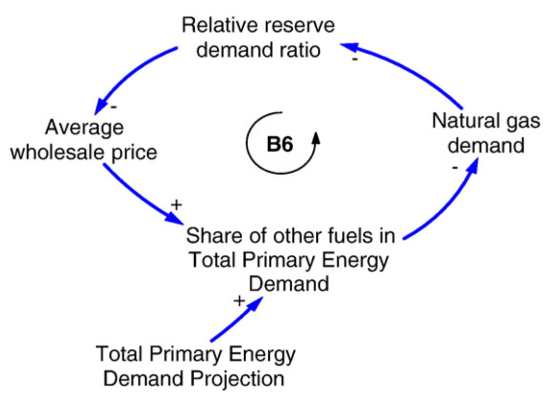

Fig. 11. Causal loop/Flow diagram of demand projection and substitution sector.

From the demand side we have introduced the substitution effect between natural gas and its main competitor fuels in TPED, i.e. coal, oil, nuclear, hydro. We assumed that coal, oil, nuclear and hydro shares in TPED are a function of gas price and time which represents other unaccounted factors determining the dynamics of energy demand. To check these assumptions the regressions were performed on 1976–2005 data for average gas price, coal, oil, nuclear and hydro energy demand [15,10]. The regressions[7] yielded:

$$\begin{aligned} &Ln\,(\mathrm{CS}) = 0.206Ln(P) - 0.046(t) - 0.001 \\ &\qquad\qquad (0.004) \quad (0.049) \quad (0.21) \\ &R^2.917 \qquad SER = .089 \end{aligned} \tag{25}$$

$$\begin{aligned} &Ln\,(\mathrm{OS}) = -0.036Ln(P) - 0.004(t) - 1 \\ &\qquad\qquad (0.002) \quad (0.025)\ (0.11) \\ &R^2 = .64 \qquad SER = .046 \end{aligned} \tag{26}$$

$$\begin{aligned} &Ln\,(\mathrm{NS}) = 0.227Ln(P) + 0.017(t) - 2.19 \\ &\qquad\quad (0.069) \qquad (0.005) \quad (0.3) \\ &R^2 = .845 \quad SER = .12 \end{aligned} \tag{27}$$

$$\begin{aligned} &Ln\,(\mathrm{HS}) = 0.151Ln(P) - 0.005(t) - 4.4 \\ &\qquad\quad (0.067) \qquad (0.005) \quad (0.29) \\ &R^2 = .25 \quad SER = .12 \end{aligned} \tag{28}$$

Results for coal, oil and nuclear were all significant (Eqs. (25)–(27)), whereas the relationship between hydro share in TPED and gas price dynamics were not (Eq. (28)), hence we excluded the hydro relationship from further analysis of gas substitution factors. Except for the oil share equation (Eq. (26)) all price coefficients have a positive sign, which indicates that an increase in gas price would cause demand for the other fuels to rise.

The regression for oil share (Eq. (26)) yielded a negative price coefficient and is relatively inelastic. This suggests that an increase in gas price would reduce demand for oil. This is due to the co-movement of oil and gas prices in UK. As mentioned earlier, the supply of associated gas in the UK has been growing and in 2004 reached about 55% of total landed UKCS gas production [1, p.11]. Secondly, due to the opening of the UK–Belgium Interconnector in October 1998 UK gas prices are partly influenced by European continental gas prices which are indexed to oil and oil-products [14, pp.7–15]. Thirdly, Panagiotidis and Rutledge analyzed UK oil and gas prices between 1996 and 2003 and found that they are cointegrated, i.e. move together over the longer term [17].

Usually when oil price is high, producers tend to increase oil production by maintaining high pressure in the wells by keeping associated gas underground, thus reducing gas supply which logically leads to an increase in gas price. But high oil prices would, on net, cause its share in TPED to decrease and therefore it is incorrect to infer that high gas price would lead to a decrease in the oil share of TPED. Since the causality between gas price and oil demand cannot be robustly inferred from empirical data, we excluded the relationship between oil demand and gas price from further analysis of gas substitution factors.

The substitution factors shown in Fig. 12 were derived from Eqs. (25) and (26) by normalising their value to 1.0 at an average gas price of 0.044 GBP/m^3 (gas price in 1987). The Oil and Hydro shares in TPED are assumed to be exogenously determined. Finally, Eqs. (29)–(35) show how gas demand is calculated.

$$\mathrm{NGD} = \mathrm{GSTPED} \times \mathrm{TPED} \tag{29}$$

$$\mathrm{TPED} = \mathrm{ITPED} \times \exp^{T \times \mathrm{TPEDGR}} \tag{30}$$

$$\mathrm{GSTPED} = 1 - (CS + OS + NS + HS) \tag{31}$$

$$\mathrm{CS} = \mathrm{CSF} \times \mathrm{ICS} \times \exp^{T \times \mathrm{CSGR}} \tag{32}$$

$$\mathrm{OS} = \mathrm{IOS} \times \exp^{T \times \mathrm{OSGR}} \tag{33}$$

$$\mathrm{NS} = \mathrm{NSF} \times \mathrm{INS} \times \exp^{T \times \mathrm{NSGR}} \tag{34}$$

$$\mathrm{HS} = \mathrm{IHS} \times \exp^{T \times \mathrm{HSGR}} \tag{35}$$

NGD Natural gas demand (m^3/year)
GSTPED Gas share in total primary energy demand (m^3/year)
TPED Total primary energy demand (MTOE/year)
ITPED Initial total primary energy demand (207.4 MTOE or 230.4 B m^3 in 1987) [9]

[7] For Eq. (25): *T* statistics and *F* statistic are significant at the 1% level.
For Eq. (26): *T* statistics are significant at the 10% level and *F* statistic is significant at the 1% level. For Eq. (27): *T* statistics and *F* statistic are significant at the 1% level. For Eq. (28): *T* statistic for price coefficient is significant at the 1% level; *T* statistic for time coefficient is insignificant; *F* statistic is significant at the 5% level.

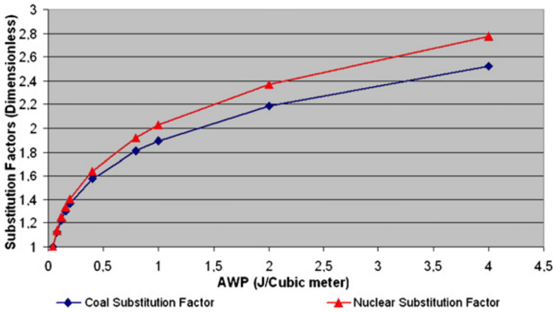

Fig. 12. AWP versus substitution factors.

TPEDGR	TPED growth rate (% per year)
CS	Coal share in TPED (%)
CSF	Coal substitution factor (dimensionless)
ICS	Initial coal share in TPED (35.5% in 1987) [9]
CSGR	Coal share growth rate (% per year)
OS	Oil share in TPED (%)
IOS	Initial oil share in TPED (36.3% in 1987) [9]
OSGR	Oil share growth rate is exogenously determined at −0.67% per year[8]
NS	Nuclear share in TPED (%)
NSF	Nuclear substitution factor (dimensionless)
INS	Initial nuclear share in TPED (6.02% in 1987) [9]
NSGR	Nuclear share growth rate (% per year)
HS	Hydro share in TPED (%)
IHS	Initial hydro share in TPED (0.675% in 1987) [9]
HSGR	Hydro share growth rate is exogenously determined at 0.49% per year[9]
T	Time (years)

4. Dynamic behaviour and validation of the model

The model results correspond relatively well to general trends for real-world data, particularly for consumption rate, cumulative gas production, share of fuels in TPED and others (see Figs. 13–16).

Some variables are generally consistent with historical data (e.g. cumulative gas production) while others diverge for part of the time series (e.g. consumption rate). One reason for the discrepancy in the trend (especially in the period after 2000 for nuclear share and consumption) is that our model does not account for imported gas, leading gas prices to be somewhat higher in the model. Another reason might be that two or more variables are interdependent as a result of the feedback loops in our model. Where simultaneity is present, the literature on regression warns that the use of OLS regression methods can give biased estimates of the regression coefficients [18]. The non-linear relationship in our model which was derived from OLS regressions may therefore be different from the actual real-world relationship. Therefore we must be aware of the results of OLS regressions in a system with feedback–loop structure.

The feedback structure of our model may introduce biases in the relationships that we have derived from OLS regressions on historical data. If there are biases in the results produced by our model than an important objective is at least to measure and report those biases. The bias can be measured by analyzing synthetic data (i.e., data from our model) and comparing them with historical data. The difference between the coefficients inferred statistically from the simulation of the synthetic data and that of real-world time series gives an approximate measure of the bias. Thus, simulation provides a method to check the validity of assumptions made when applying linear regression methods to System Dynamics models. This estimation procedure was applied to the table functions of our model (the factor and multiplier curves in our model) and the results are reported in Table 1.

Figs. 17 and 18 show the behaviour of the UK model of indigenous gas production under the Base Case assumptions (i.e., the model is simulated using actual UK gas industry data). The production rate peaked in 2000. The production rate is constrained by proved reserves, actual consumption, and investment potential. As proved reserves begin to fall, the production rate follows this trend.

The AWP remains low until the variable RDR falls below 20 years (Fig. 18). The expectation of a future reserves deficit based on demand projections causes the price to go up, signalling that additional discoveries are required. For example, during 2001–2008, industry responded to high prices by tapping additional discoveries (Fig. 17). DR stayed at a low level thereafter (Fig. 17) since a

[8] Based on data from 1976–2005 average oil demand in TPED exhibited a decline of 0.67% per year [10].
[9] Based on data from 1976–2005 average hydro energy demand in TPED grew at 0.49% per year [10].

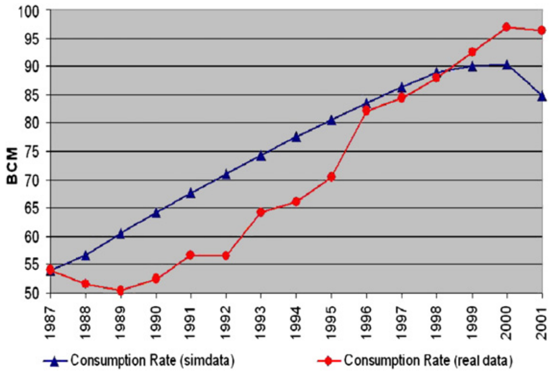

Fig. 13. Consumption rate: simulated versus real data.

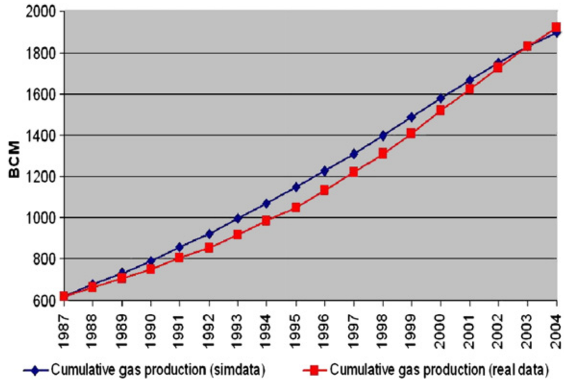

Fig. 14. Cumulative gas production: simulated versus real data.

further decrease in RDR causes AWP to rise, which depresses consumption and production. In reality, consumption will continue to rise because gas imports will balance out increasing prices for indigenous UK gas.

5. Analysis of alternative scenarios

The success in matching historical data does not ensure the reliability of forecasts… As Sterman [19, p.331] notes: "…the ability of the model to replicate historical data does not, by itself, indicate that the model is useful". In this section we develop a range of scenarios to examine model behaviour across various possible futures. These scenarios do not represent any particular government policies existing now or in the past. Rather, they are answers to 'what if' questions and represent a range of possible policies in a declining gas production industry. Since the model was calibrated using 1987 industry data (the earliest possible year where all data required for our model was available). The alternative scenarios will be introduced at the beginning of the model run.

The objective of the model is to examine various policies which could affect the development of the UK gas industry. For example, using the model we compare various taxation policies and technological development scenarios. We also check how the model behaves in extreme demand cases. The assumptions of growth rate of gas demand scenarios should be regarded as extreme values rather than real demand projection. So to analyze these issues we consider cases with the following assumptions:

1. Low Taxation Policy (both Royalty and Petroleum Revenue Tax (PRT) are 0%)[10]
2. High Taxation Policy (Royalty is 20%, PRT is 70%)
3. High demand projection—7% growth per year (compared to 3.5% p.a. in the Base Case)[11]
4. Low demand projection—1% growth per year
5. Advanced exploration and recovery technologies—we assume that with advanced technologies the unit cost of exploration and production would decline at 5.33% per year[12].

[10] Real taxation policy for UK indigenous oil and gas production—Royalty is 12.5% for all fields which were developed before 1982, after that time Royalty is 0%; PRT is 50% for all fields which were developed before 1993 after that time PRT is 0% [20].

[11] The growth rates for the demand cases were based on historical trends in UK natural gas consumption from 1965–2005, which varies considerably over the time horizon. In the initial period of introduction of gas usage in UK 1965–1974 average annual growth rate was 48%; in the period 1975–1984 average growth rate was 3.31%; in the period 1985–1995 average growth rate was 3%; in the period 1996–2005 average growth rate was 1.7% (authors' calculations based on [10]).

[12] A 5.33% p.a. reduction in cost of exploration resulting from technological advancements was taken from [22, p.45].

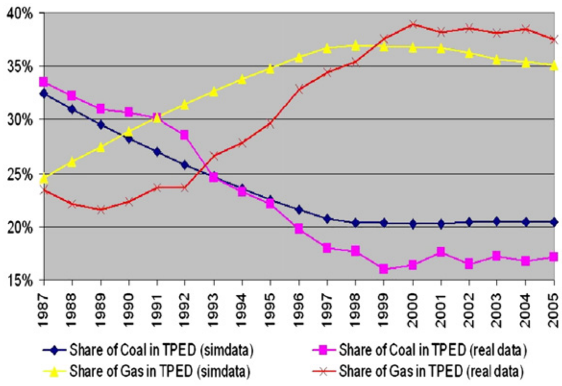

Fig. 15. Shares of coal and gas in TPED: simulated versus real data.

5.1. Taxation policy cases

In general Taxation Policy (TP) cases have the strongest impact on discovery rate. As was discussed earlier discovery rate (DR) is affected by two factors—industry's ROI and future demand. Since taxation policy has a direct influence on industry's returns, higher taxation policy, *ceteris paribus*, decreases industry's returns and hence its investment in E&A (loop B2). In the Low Taxation Case (LTC), initial value of DR is 33% higher than in the Base Case due to higher ROI which directly affects E&A investment (see Table 2). Due to anticipated demand growth, DR in both cases (LTC and High Taxation Cases (HTC)) rises in the period 2000–2006. The turning points of DR are the same in all three cases (Fig. 19).

In general, HTC discourages discovery of gas in the short term and the initial value of DR is 13% less than that of Base Case. The LTC might be expected to encourage more discoveries, but the cumulative gas discovery for this case is actually 0.2% lower than that of Base case. In the HTC, the cumulative gas discovery is about 1.8% less in value than that of Base Case. These results suggest that TP Cases are most efficient in the short term and their relative effectiveness in the long run do not differ considerably from that of Base Case. The analysis of production, consumption and price patterns in TP cases yields almost the same results (Table 2).

5.2. High and low demand cases

The analysis of demand cases shows that the model is quite sensitive to initial demand conditions. In particular, the High Demand Case (HDC) shifts the peak of the discovery rate, so that it peaks 3 years earlier and was about 100% higher in value than in the Base Case (Table 2). The consequence of such a high rate of discoveries is a rapid increase in price due to the depletion effects on E&A drilling costs. In general, the HDC forces both production and consumption to peak earlier with higher values than in the Base Case but shortens the overall lifetime of both production and consumption.

Lower demand increases the RDR and thus discourages investment in E&A. As a result, the DR peaks 9 years later at a relatively lower level than in the Base Case. Production and consumption follow the same pattern as DR. This case leads consumption to peak 7 years later at a 28% lower value than the Base Case. In the Low Demand Case (LDC) the price stays low. This is due to the fact that low demand has constrained the DR throughout the modelling period and thus the gas price is lower than it otherwise would have been. Although gas prices in the demand cases vary considerably, they have limited effects on cumulative gas consumption (see Table 2) due to a relatively low elasticity of consumption (Eq. (22)) (Fig. 20).

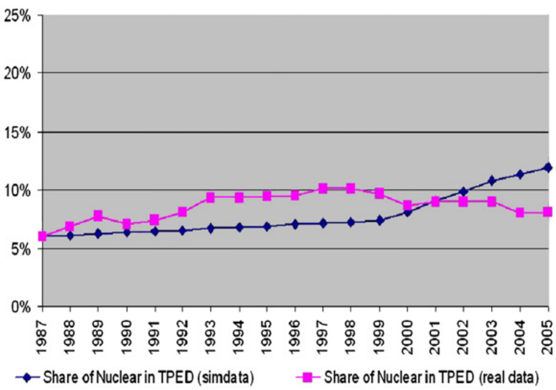

Fig. 16. Shares of nuclear in TPED: simulated versus real data.

Table 1
Comparison of regressions on real and synthetic data

Table functions	OLS regressions on historical data	OLS regressions on synthetic data
COE&A Multiplier	$Ln\,(\mathrm{COE\&A}) = -21.66Ln(FURR) - 4.5$ $R^2 = .731;\ SER = .44$ (4.4) (0.26)	$Ln\,(\mathrm{COE\&A}) = -21.95Ln(FURR)$ -4.33 $R^2 = .99;\ SER = .06$ (0.1) (0.02)
ROI Factor	$Ln(\mathrm{PSIE\&A}) = 0.68Ln(\mathrm{ROI}) - 1.2$ $R^2 = .96;\ SER = .04$ (0.1) (0.05)	$Ln\,(\mathrm{PSIE\&A}) = 0.686Ln(\mathrm{ROI})$ -1.19 $R^2 = .99;\ SER = .001$ (0.001)(0.00012)
RRDR Factor	$Ln\,(\mathrm{PSIE\&A}) = -1.04Ln(RRDR) - 0.95$ $R^2 = .97;\ SER = .036$ (0.14) (0.019)	$Ln\,(\mathrm{PSIE\&A}) = -0.99Ln(RRDR)$ -1.4 $R^2 = .92;\ SER = .12$ (0.075) (0.055)
PC Factor	$Ln\,(\mathrm{PC}) = 0.28 - 1.56Ln(\mathrm{RRPR})$ $R^2 = .92;$ SER $= .11$ (0.036) (0.134)	$Ln\,(\mathrm{PC}) = 0.38$ $- 1.52Ln(\mathrm{RRPR})$ $R^2 = .99;$ SER $= .09$ (0.019) (0.015)
PSIP Factor	$Ln\,(\mathrm{PSIP}) = 0.88Ln(\mathrm{ROI}) - 1.098$ $R^2 = .82\ SER = .1$(0.24)(0.15)	$Ln\,(\mathrm{PSIP}) = 0.82Ln(\mathrm{ROI})$ -1.13 $R^2 = .99\ SER = .001$ (0.0004) (0.0001)
Price Factor	$Ln\,(P) = 0.11 - 2.03Ln(\mathrm{RRDR})$ $R^2 = .9;$ SER $= .08$(0.03)(0.34)	$Ln\,(P) = 0.83$ $- 2.01Ln$ (RRDR) $R^2 = .99;$ (0.005) (0.01) SER $= .02$
Consumption Factor	$Ln\,(C) = 2.56 - 0.42Ln(P) + 0.054(t)$ (0.41) (0.13) (0.004) $R^2 = .945$ SER $= .063$	$Ln\,(C) = 2.9 - 0.46Ln(P) + 0.06(t)$ (0.28) (0.07) (0.009) $R^2 = .96$ SER $= .18$
Coal substitution Factor	$Ln\,(\mathrm{CS}) = 0.206Ln(P) - 0.046(t) - 0.001$ (0.049) (0.004) (0.21) $R^2 = .917$ $SER = .089$	$Ln\,(\mathrm{CS}) = 0.206Ln(P)$ $-0.046(t)$ -0.054 (0.002) (0.0003) (0.008) $R^2 = .99$ $SER = .002$
Nuclear substitution Factor	$Ln\,(\mathrm{NS}) = 0.227Ln(P) + 0.017(t) - 2.19$ (0.069) (0.005) (0.3) $R^2 = .845$ $SER = .12$	$Ln\,(\mathrm{NS}) = 0.226Ln(P)$ $+0.017(t)$ -2.07 (0.003) (0.001) (0.014) $R^2 = .99$ $SER = .004$

5.3. Advanced technology case

The impact of better exploration and production technologies on consumption rate is limited in the short term but has a considerable effect in the long run. The cumulative gas consumption in this case is about 150% higher in value than in the Base Case (Fig. 21). In the long term, lower costs of exploration and production resulting from technological improvements increases the discovery rate, production and consumption rates compared with the other cases (see, e.g., Figs. 19 and 21).

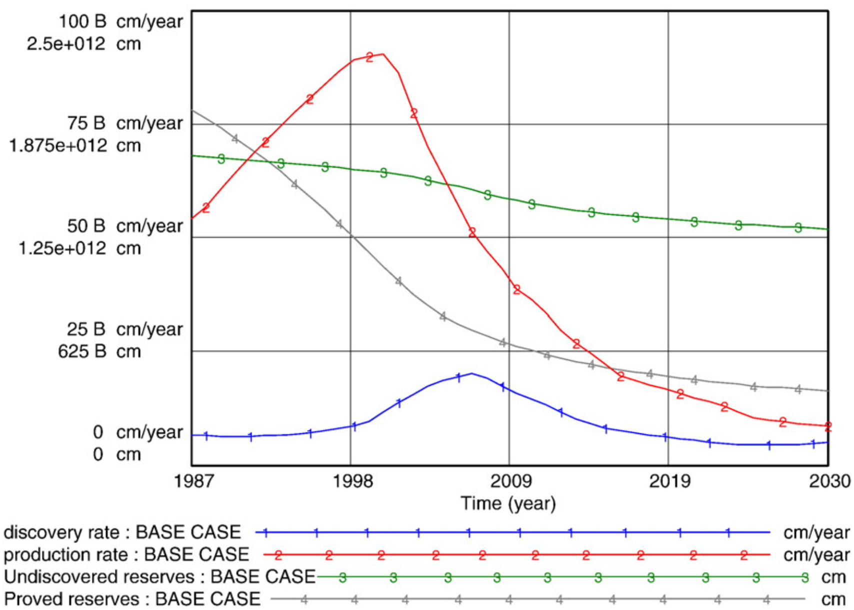

Fig. 17. Behaviour of DR, PRR, UR and PR in Base Case.

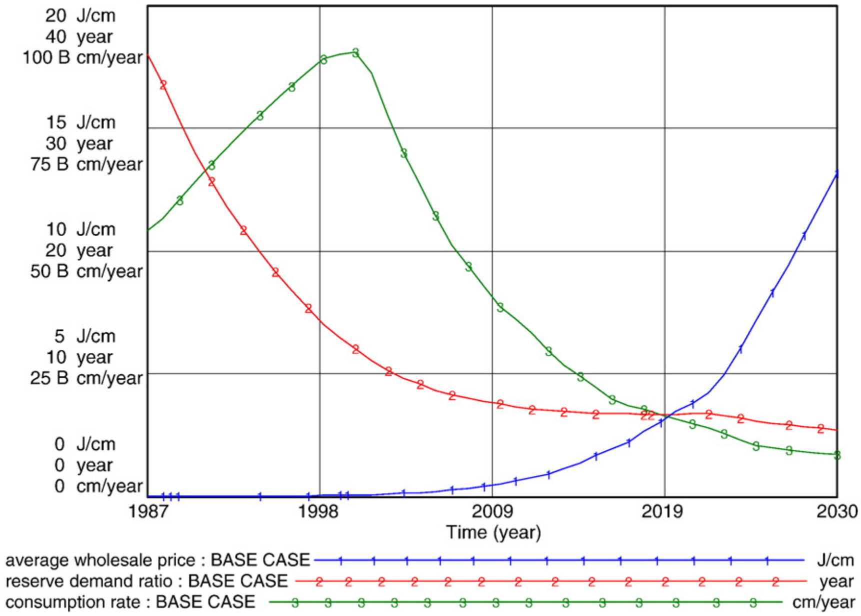

Fig. 18. Behaviour of AWP, RDR and CR in Base Case[13].

Due to the long-term effects of technological improvements, the consumption peaked at the same time as in the Base Case. The direct impacts of improvements in exploration and production technology are lower cost and consequently lower gas prices. The overall impact of improvements in exploration and production technology is to extend the lifetime of gas reserves and postpone the depletion effects on costs considerably allowing gas usage to continue for a longer time.

5.4. Rising gas import-dependence in UK

Analysis of alternative policies indicates that the most effective policies for prolonging indigenous gas production and consumption are those dealing with demand side, but the optimal policy should be one that combines both supply and demand side measures. Continued demand growth, depletion of gas resources, and long delays in the implementation of energy policy raise the possibility of a significant gap between gas demand and indigenous production [3, p.5]. Under these conditions, the UK will rely on massive gas imports to balance supply and demand during the coming decades. The consequences of rising import-dependence could result in supply interruptions due to geopolitical risks. Therefore we suggest that much effort be undertaken by both British and European energy policy makers to deliver a genuine European gas market informed by transparent and reliable information concerning gas reserves worldwide.

Fig. 22 illustrates the results of the combined supply–demand policy (Supply–Demand Case), which assumes: (i) reduced demand (e.g. by successful implementation of energy efficiency policies), which would stabilise gas demand growth at 1% p.a.; and reduced taxation to encourage R&D in exploration and production technology. The result of the combined policy is that, in the long term, gas imports will be minimal due to extension of the lifetime of indigenous gas production which is associated with reliability and secure supplies for domestic customers. Management of import-dependence thus should not be reduced to focus solely on the design of responses to the unreliability of exporting countries but rather should emphasise the development of a combination of external and internal policies.

The size of the resource base in European countries such as the UK, Norway or Netherlands can only play a limited role in postponing the time when the whole EU would be heavily dependent on external gas resources. The only way to increase the reserve base is through technological advances, which in the past several decades has actually broadened the reserve base through improvements in recovery technologies [21].

6. Conclusion

As the UK becomes more dependent on natural gas imports, successes achieved in domestic natural gas markets might be undermined if not matched at an international level. Efforts to design an energy policy require long-range planning because of the lead times required for policies to have their full effect. For example, the growing gas import-dependence in the UK is a direct result of the policies adopted by successive governments during the past two decades e.g. those aimed at promoting the fastest possible exploitation of indigenous gas reserves and large-scale exports [23].

[13] Price is measured as GBP/m^3 (J/m^3) so the Y-axis runs from 0 through 20 J/m^3.

Table 2
Main variables' turning points and discrepancies from Base Case (BC) results

Main indicators	Discovery rate			Consumption rate			Undiscovered reserves	Proved reserves	AWP	
Alternative scenarios	Turning point		Cumulative value relative to BC (%)	Turning point		Cumulative value relative to BC (%)	Cumulative value relative to BC (%)	Cumulative value relative to BC (%)	Time when AWP exceeds 0.9 GBP/m^3 (which is roughly ten times the level of 2005 gas price [15])	Price at the end of simulation (relative to BC) (%)
	Year	Relative to BC (%)		Year	Relative to BC (%)					
Base Case (BC)	2006	–	–	2000	–	–	–	–	2012	–
Low Taxation Case	2006	+2	−0.27	2000	−0.1	−0.4	−0.1	+0.5	2013	−2.3
High Taxation Case	2006	−4.5	−1.7	2000	+0.01	+0.3	+0.5	−1.1	2012	−3.1
Advanced Technology Case	2017	+99	+149	2000	+0.2	+16.7	−12	+11	2018	−74.8
Low Demand Case	2015	−7	+33	2007	−27.6	−0.9	+17.2	+7.8	2020	−41.5
High Demand Case	2003	+107	−6.3	1998	+19.4	−13.7	−10.5	+16	2005	+1400

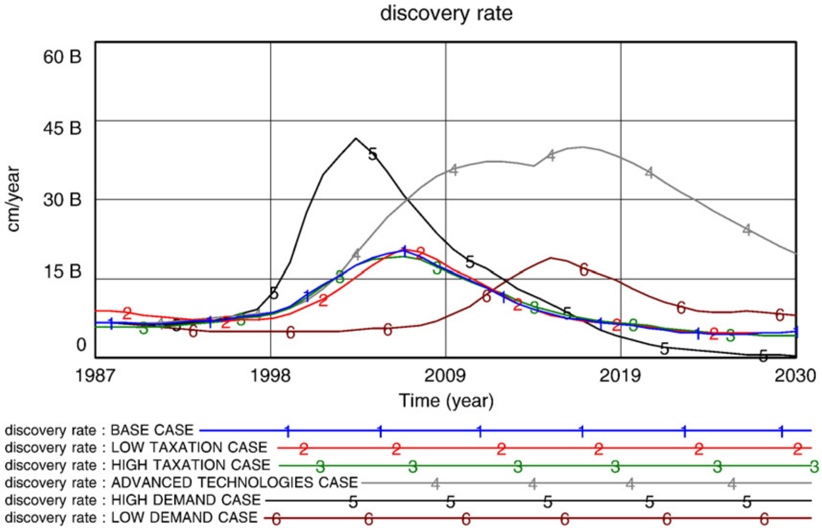

Fig. 19. Dynamics of DR in alternative cases.

More generally, energy policy involves long time scales because of the inherent delays involved in the energy system. If the UK Government designs a new energy policy to address the issue of growing import-dependence in the next decades, it should also include analysis of possible problems and consequences of current policies and try to look far beyond the problem of security of supply and import-dependence on unstable exporters.

The model presented here could be useful for prediction purposes since it has shown minimal discrepancies with historical data of the main variables. The functional forms of the various assumptions made in this model are able to represent historical data and dynamic behaviours quite well, but there is no assurance *that the same functional forms* will be correct in *the future*. In any case, this type of model does offer a useful experimental tool for determining how various assumptions about physical, technological and economic factors affect patterns of growth or decline.

By running different scenarios, several fundamental dynamic behaviours can be seen explicitly. For instance, the concept of exponential growth is very important for designing long-term energy policy since our analysis shows that supply policies (TP cases) alone cannot substantially postpone the discovery, production or consumption peak. We also found that main parameters, namely, exploration, production and consumption are quite sensitive to initial demand conditions. Postponing the onset of rising gas price can be achieved more effectively through efforts to reduce demand than through efforts directed at the supply side. Improvements in exploration and production technology can delay the peak time of exploration, production and consumption. The overall effects of technological improvements are an increase in reserve lifetime, lower gas price and consequently prolonged gas usage.

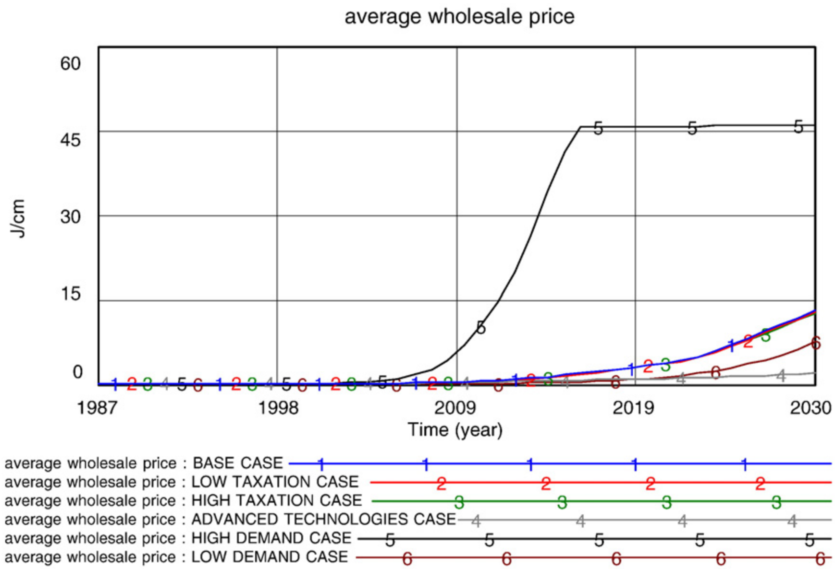

Fig. 20. Dynamics of AWP in alternative cases.

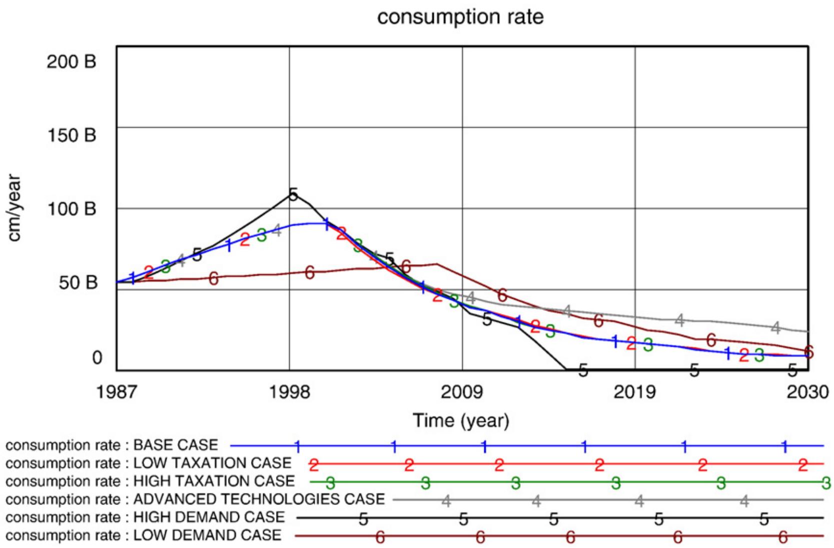

Fig. 21. Dynamics of CR in alternative cases.

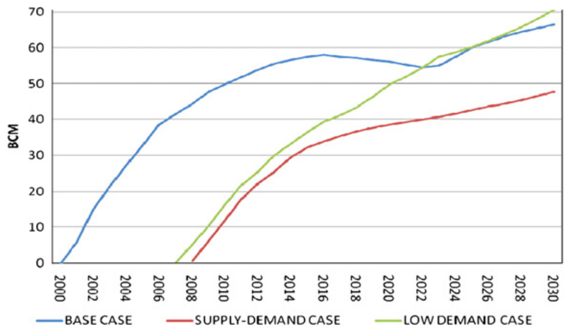

Fig. 22. Dynamics of natural gas imports in alternative cases.

Nonlinear systems sometimes exhibit responses to policy changes that seem to support policy goals in the short term, but over the longer term, the system returns to its pre-policy-change state or produces an even worse situation. This reversion occurs when the system's feedback structure works to defeat the policy change designed to improve it [19, p.5]. A short-term policy of supply-side management, e.g. through various taxation policies, might exhibit policy resistance. For example, it is logical that the Low Taxation Policy should encourage more exploration and production of gas and therefore stimulate a higher consumption rate; but there were no substantial effects over the long run, i.e. in the Low Taxation Case cumulative gas consumption is even less than that of the Base Case. One explanation for the policy resistance could be the declining marginal rate of discovery which leads to higher cost, higher prices, and lower consumption over the long-term.

Appendix

Table A.1
Main causal loops of the dynamic model of UK natural gas industry

Exploration sector			Production and consumption sector		Demand and substitution sector
Loop B1	Loop B2	Loop B3	Loop B4	Loop B5	Loop B6
Undiscovered reserves; Fraction of undiscovered reserves remaining; Cost of E&A; Indicated discovery rate; Discovery rate; Undiscovered reserves.	Undiscovered reserves; Fraction of undiscovered reserves remaining; Cost E&A; Industry's ROI; Investment in E&A; Indicated discovery rate; Discovery rate; Undiscovered reserves.	Proved reserves; Relative reserves demand ratio; Investment in E&A; Indicated discovery rate; Discovery rate; Proved reserves.	Production rate; Relative reserves production ratio; Production cost; Industry's ROI; Desired investment in production; Desired production rate; Production rate.	Production rate; Proved reserves; Relative reserve–demand ratio Average wholesale price; Consumption rate; Production rate	Relative reserve–demand ratio; Average wholesale price; Share of other fuels in TPED; Natural gas demand; Relative reserve–demand ratio.

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