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A Programming Model of Australian Crude Oil and Condensate Supply

A Preliminary Analysis

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There is little published work on the economic determinants of Australian crude oil and condensate supply. This is surprising, since such knowledge is likely to be an important input in forecasting crude oil and condensate supply and in analysis of policies affecting the petroleum industry. In this paper, initial research designed to construct a multi-period programming model of Australian petroleum crude oil and condensate supply, based on a model of natural gas supply in Canada, is presented. Time paths for operating costs, discoveries and the world crude oil price are exogenously specified. The properties of the model are examined by simulating the effects of alternative input and output price paths on crude oil and condensate supply response. Directions for further research are suggested.

Introduction

Both industry and government prepare forecasts of Australian crude oil and condensate supply, using models of varying geological and economic complexity. The purpose in this paper is to outline an approach to modelling Australian crude oil and condensate supply response which takes into account a number of the economic factors influencing supply response in the use of a non-renewable resource. A programming model is described which is designed to be useful for forecasting purpose. The emphasis is on the economic choices involved in the supply response for crude oil and condensate.

The initial research efforts reported in this paper are designed to permit analysis of the economic content of geologically based forecasts. The overall objective of the research is to provide a modelling system which can assist with the generation of crude oil and condensate supply forecasts. These forecasts need to take into account, in an integrated way, world crude oil prices and the input costs involved in exploration, development and extraction. For example, a set of geologically based forecasts obtained from industry become exogenous constraints (upper or lower bounds) in the programming model. The model can then be used to determine whether the forecasts are reasonable in an economic context. Thus, the programming model is designed to generate supply forecasts which are consistent with an economic welfare optimum given the exogenous input and output prices.

A multi-period and multi-region optimisation model of crude oil and condensate supply response in Australia is outlined. A multi-period perspective is used because there is an opportunity cost to the depletion of crude oil and condensate reserves. A multi-region framework is required to capture spatial differences in resource endowments and production technologies. The medium run model of Australian crude oil and condensate supply outlined in the paper is adapted from the nonlinear programming model developed by Rowse (1988) to analyse natural gas supply in British Columbia.

It may be noted that taxation policy and technological change are likely to be important determinants of crude oil and condensate supply response. Such rather complex possible refinements to the model are not addressed in this initial report. Rather, the focus in this paper is on documenting the Australian version of the Rowse model and, through simulation, presenting a critical appraisal of its current structure.

The paper is organised as follows. In the next section, a short review of some of the background literature is given. The programming model is outlined in the following section.

Next parameter settings are described, and simulation results are then discussed. Directions for future research are identified in the final section.

Literature Background

The international research literature on crude oil supply is considerable. A critical review of this literature is provided in Kaufman (1987). Methodologies vary widely as to their emphasis on forecasting and policy prescription. Models also differ in their emphasis on geological and economic linkages in crude oil supply response.

Reserves of non-renewable resources are depleted by extraction and increased by discovery and intensified recovery effort. Resource production decisions must take this process into account. An assessment of the 'user cost' of current production is one key ingredient in the production decision. This assessment includes the formulation of expected future prices, cost conditions and discovery patterns. Geological and economic uncertainty therefore also influence production decisions.

Crude oil and condensate supply response models may be classified into three categories: econometric models, discovery process models and programming models. Econometric models of crude oil and condensate supply response tend to separate the discovery process from the extraction process. That is, models of reserve discovery are separately estimated from models of production. This technique is used explicitly or implicitly by Epple (1975), Pakravan (1984) and Livernois and Ryan (1989).

Econometric models of supply response for non-renewable resources tend to have poor forecasting records (Kaufman 1987). This may reflect such factors as structural change in markets, geological and capacity constraints on production profiles and expectations of future price and cost conditions which differ substantially from past experience. By contrast, discovery process models are widely used to forecast undiscovered reserves and production from these reserves at a disaggregated level. Discovery process models are designed to model the process of petroleum discovery and depletion in a petroleum basin. Reservoir discovery is typically modelled using a successive sampling procedure.

One of the most sophisticated discovery process models is SEAPUP, developed at the Australian Bureau of Mineral Resources by Forman and Hinde (1985, 1986). The SEAPUP model is based on the work of Barouch and Kaufman (1977). In particular, it is designed to provide probabilistic forecasts of undiscovered Australian reserves of crude oil and condensate and of the corresponding production flows. Economic factors are largely exogenous to the model and enter indirectly through shock variables such as exploratory drilling effort and minimum economic field size. The model framework draws heavily on the concept that large fields are likely to be discovered first — that is, the 'creaming effect'. The forecasting performance of this model has not been rigorously assessed.

Programming methods are well suited to estimating crude oil and condensate supply response. In general, programming models have the advantage of allowing for considerable flexibility in incorporating real world complexities in supply response behaviour while remaining computationally tractable. Research by Rowse (1986, 1987, 1988) has highlighted these advantages. Fixed resource recovery profiles, transitions to 'backstop' sources, the possibility of non-production, deliverability constraints, rising unit capital cost functions and regional differences in production technologies may be incorporated into these models. Backstop sources in such models are assumed to have infinitely elastic supply curves.

Projections from discovery process models can be used as exogenous constraints in a programming model designed to place these projection results within the contexts of changing cost and price conditions and of the opportunity cost of forgone consumption. Using such a model, forecasts consistent with an economic welfare maximum can be determined, given exogenous paths for relevant input and output prices. For these reasons, the programming method was chosen in this study.

A Programming Model

Key assumptions

The model of crude oil and condensate supply outlined below is adapted from the Rowse model of natural gas supply in British Columbia (Rowse 1988). The following assumptions are common to both models.

(1) There exists a perfect substitute for domestic product. In the Australian model this 'backstop' comprises endogenously determined foreign imports at an exogenously specified price.

(2) Production from existing reserves is distinguished from new reserves discovered within the forecast horizon. Production profiles for new reserves and for the re-opening of existing reserves which have been shut-in (that is, taken out of use for a time), are given.

(3) There are exogenous unit extraction costs and deliverability constraints on domestic supplies.

The Australian model has the following additional features.

(4) There are multiple sources of domestic supply.

(5) There is one centrally located domestic market for all petroleum products.

(6) The sum of exploration and development efforts, or 'finding effort', is represented explicitly in the Australian model, whereas it is subsumed in a 'reserve commitment' variable in the Rowse model (see 'New discoveries' below).

A brief explanation of these additional features is given in the following subsections.

Multiple sources of supply

The operating environment and reservoir characteristics are key determinants of the technology used to exploit an oil field. For example, drilling costs, a major component of set-up costs, are a function of depth and location. Three domestic supply regions, distinguished by production technology, are incorporated in the Australian model. These comprise: region 1 — offshore production from fixed production platforms; region 2 — offshore production from floating production platforms; and region 3 — onshore production.

There are a number of factors affecting cost differences across the three supply regions. Capital costs for floating facilities are significantly below those for fixed offshore platforms. Typically, fixed platforms are used for large fields with slow production decay while floating systems are used for small fields with rapid production decay. In general, per-metre exploration and development drilling costs tend to be larger for offshore ventures than for onshore ventures. However, in assessing the drilling cost component of an oil project the finding success rate (reserves added per additional metre drilled) is also important. If costs per metre are low but the finding success rate is also low then drilling costs may be assessed as high. In Australia, historical finding success rates favour offshore ventures. The development of horizontal drilling techniques has also reduced the gap between onshore and offshore supply costs. A further reason for differences in operating costs across regions lies in the cost of transporting inputs and outputs.

Market clearance

In this paper, 'net imports of petroleum products' refers to the difference between domestic demand for petroleum products and the sum of domestic regional supplies of crude oil and condensate. Thus, it is assumed that rest-of-world and domestic crude oil and condensate and refined petroleum products are all perfect substitutes. Regional and product disaggregation of demand and the inclusion of imperfect substitution between products would be important real world modifications to the model.

New discoveries

In the Rowse model the whole supply process, from exploration to extraction, is telescoped into 'new reserves booked or committed for supply' and an associated supply profile. The production profile for the supply process comprises a given time lag between exploration and development plus a production profile for extraction. The full supply profile is then applied to the known reserve commitment variable to determine production.

A rising unit 'capital' cost function is also specified in the Rowse model. This has the feature that costs rise exponentially as cumulative new commitments approach ultimate reserves available. The function used by Rowse (1988) is simply imposed rather than based on econometrically estimated parameters. In the Australian model, a similar rising unit 'capital' cost curve is implied for new reserves by separately modelling exploration plus development drilling effort and discoveries. Drilling effort and discovery parameters can then be econometrically estimated.

Drilling activity is a major component of set-up costs in exploration and development. In the Australian model, drilling effort is assumed to be a function of the real world price of crude oil and set-up costs per unit output. Following Reinsch and O'Reilly (1990), cumulative drilling effort leads to new discoveries or reserve additions according to a logistic growth process. It is assumed that new reserves discovered are known with certainty; thus, geological uncertainty is not included in the model. However, it could be incorporated through stochastic simulation procedures or stochastic programming methods.

Model equations

The Australian programming model was solved in a primal–dual form. Whereas Rowse employed a net social welfare objective function, in the Australian model a net social revenue form, analogous to the net social welfare objective functions of Takayama and Judge (1971), is used. An advantage of the primal–dual form of model is that it provides for the possibility of including constraints on both price and quantity variables, and thus for the inclusion of a number of the more complex policy arrangements. For example, tax wedges may be introduced into the arbitrage conditions. For the primal–dual form an optimal solution must yield an objective function value of zero, since the primal solution must equal the dual solution at the optimum. This is a useful technical check on the construction of the model. In addition, the dual equations represent price relationships through time which provide insights into the equilibrium solution. For expositional ease below, the primal version of the model is presented first followed by the dual constraints and the revised objective function for the primal–dual form.

Notation

Quantities are represented by upper case letters (see Table 1) and corresponding prices in lower case. Greek letters denote model parameters. Subscript i refers to the production region $\{i=1,..,I\}$ and subscript t denotes year t $\{t=1,..,T\}$. A starred variable indicates that the variable pertains to newly discovered reserves, where this distinction is necessary. Variables prefixed by the letter C indicate the cumulative value of a given variable. A full list of model variables is provided in Appendix A.

TABLE 1
Summary of Variable Names

C	= cumulative value
D	= maximum domestic supply
E	= exploratory and development or finding effort
M	= petroleum imports
Q	= domestic demand
r	= interest rate
U	= maximum new domestic discoveries
V	= scrap value
X	= domestic supply from pre-existing reserves
XS	= domestic reserves shut-in
XS^*	= newly discovered domestic commercial reserves
Y	= newly discovered domestic commercial plus non-commercial reserves

The primal problem

The net social welfare objective function to be maximised, consumer plus producer surplus, is:

$$(1)\quad \underbrace{\sum_t \int_0^{Q_t} F_{at}(Q_t)\, dQ_t /(1+r)^t}_{A} - \underbrace{\sum_i \sum_t x_i X_{it} /(1+r)^t}_{B} - \underbrace{\sum_i \sum_t xs_i^* XS_{it}^* /(1+r)^t}_{C}$$

$$-\underbrace{\sum_i \sum_t e_{it} E_{it} /(1+r)^t}_{D} - \underbrace{\sum_t m_t M_t /(1+r)^t}_{E} + V$$

All terms in (1) are discounted to period-0 values using interest rate, r, and the summations apply to the full range of values for the relevant variables. Term A in the objective function is the sum of the integrals of the inverse demand functions. Q_0 is the domestic demand for petroleum products in period 0 and is exogenous. The inverse demand function for oil and condensate in Australia (region a) for period t is:

$$(2)\quad F_{at}(Q_t) = (\alpha_{1t}\, Q_{t-1}{}^{\alpha 3}/Q_t)^{1/\alpha 2}$$

Term B denotes costs of extraction from pre-existing reserves. Term C represents extraction costs for newly discovered reserves, where XS^*_{it} is the stock of new reserves found in region i and period t from which production flows according to a T-period profile $\{t = t_0, ..., t_0+T-1;\ \beta^* = \beta_1^*, ...,\beta_T^*;\ 0 \le \beta_t^* \le 1;\ \sum_t \beta_t^* = 1\}$. Extraction costs for the stock of newly committed reserves in region i and period t is the profile-weighted sum of unit extraction costs per time period

$$(3)\quad xs_i^* = x_i^* \sum_t \beta_{it}^* /(1+r)$$

Note that x_i^* therefore denotes per-unit operating costs for new reserves in (3).

Term D pertains to finding and development costs for reserves discovered within the T-period forecast horizon. As in Rowse (1988), such costs for pre-existing reserves are regarded as sunk and so were omitted from (1). Term E refers to the cost of backstop imports, and V is the scrap value of unused resources at the end of the extraction period

$$(4) \quad V = \sum_i (m_T - x_i) \sum_t XS_{it} \sum_k \beta_{i\,T+k-t} /(1+r)^{T+k}$$

$$+ m_T \sum_i \sum_t XS_{it}{}^* \sum_k \beta_i{}^*{}_{T+k-t} /(1+r)^{T+k-1}$$

Supplies at the horizon are valued at the world import price for oil less the cost of extraction. In particular, in equation (4) pre-existing reserves which are shut-in in period t_0 can only be recovered according to a T-period profile $\{t = t_0+1,..,t_0+T$: $\beta = \beta_1,..,\beta_T$; $0 \leq \beta_t \leq 1$; $\sum_t \beta_t = 1\}$ where β_t is the fraction recovered in a given period. Their value at the forecast horizon is net of operating costs. The same holds for newly discovered reserves not produced by period T. Also note that in (4) the last summation runs from k=1 to t for existing reserves while for new reserves it runs from k=2 to t.

The primal constraints are outlined next, and where relevant the corresponding dual variables are bracketed at the end of each of the equations.

First, domestic demand for petroleum products cannot exceed domestic supplies of crude oil and condensate and imports of petroleum products:

Production–consumption balance

$$(5) \quad Q_t - \sum_i X_{it} - \sum_i \sum_k \beta_i{}^*{}_{t-k+1} \, XS_{ik}{}^* - M_t \leq 0 \quad \{ q_t \}$$

where the first summation is from i=1 to I and the second summation is from k=1 to t.

Second, there are *deliverability constraints* on production from newly discovered and existing reserves (shut-in) respectively:

$$(6) \quad \sum_k \beta_i{}^*{}_{t-k+1} \, XS_{ik}{}^* - D_{it}{}^* \leq 0 \quad \{ d_{it}{}^* \}$$

and:

$$(7) \quad X_{it} + XS_{it} - \sum_k \beta_{i\,t-k+1} \, XS_{ik} - D_{it} \leq 0 \quad \{ d_{it} \}$$

where the summation is from k=1 to t in (6) and k=1 to t-1 in (7). Note that in equation (7) what is produced plus what is shut-in cannot exceed the deliverability limit, determined by pumping capacity, plus reserves available from previous shut-in resources.

Third, it is assumed that the discovered commercial reserves cannot exceed total reserves discovered:

(8) $XS_{it}^* - Y_{it} \leq 0 \quad \{ y_{it} \}$

Now, largely following Reinsch and O'Reilly (1990), total cumulative reserves discovered are determined from cumulative finding effort, while finding effort depends on output price and input cost conditions. In particular, a logistic growth curve is specified for cumulative discoveries :

Cumulative discovered reserves

(9) $CY_{it} = U_i / [\, 1 + \gamma_{0i} \exp(-\gamma_{1i} \; CE_{it}) \,]$

where:

(10) $CY_{it} = \sum_k Y_{ik}$

(11) $Y_{it} = CY_{it} - CY_{it-1}$

Cumulative finding effort

(12) $CE_{it} = \sum_k E_{ik}$

and the summations are from k=1 to t. Note that the use of the logistic curve means that cumulative new discoveries (CY_{it}) must always be less than the ultimate potential discoveries (U_i). CY_{i0} represents cumulative discoveries in period 0, which are exogenously specified.

In addition, finding effort is assumed to be a log-linear function of the real world import price for crude oil, m_t, and per-unit drilling costs, e_{it}:

Drilling or finding effort

(13) $E_{it} = \delta_{0i} \, m_t{}^{\delta_{1i}} / e_{it}{}^{\delta_{2i}}$

A few comments are in order regarding the drilling and discoveries equations (9) – (13). As modelled, finding effort depends only on variables exogenous to the rest of the model, and the same also holds for cumulative discoveries. This means that term D in the primal objective function is fixed exogenously and is thus predetermined in the model. Hence, term D can be dropped from the primal objective function and equations (9) to (13) solved for Y outside the mathematical optimisation routine. Hence, in what follows, equations (9) through (13) are subsumed in (8), effectively making the discoveries determined by world prices. This is a restriction on the model that will be relaxed in future work.

The dual constraints

The dual constraints are derived by forming the Lagrangian function for the primal problem and partially differentiating this function with respect to the primal variables (Takayama and Judge 1971, pp. 16-17). The resulting dual equations essentially represent arbitrage conditions. Note that the corresponding primal variables are bracketed at the end of each of the equations. Further, note that the drilling and discoveries equations are excluded from this derivation.

First, the supply price of oil for Australia as a whole (region a) cannot exceed the demand price of oil:

$$(14) \quad F_{at}(Q_t) / (1+r)^t \leq q_t \quad \{ Q_t \}$$

Second, the effective supply price of the current and future stream of new reserves cannot exceed the corresponding effective in-ground price plus scarcity premiums and extraction costs less the salvage value of new reserves not produced. New reserves will only be committed for supply in the current period, t, if the return from this action covers the opportunity cost of not supplying them in the current period; otherwise they will remain in the ground:

$$(15) \quad \sum_k [\, \beta_{ik}^*(q_{t+k-1} - d^*_{i\,t+k-1}) - y_{t+k-1} \,] \leq xs_i^*/(1+r)^{t-1}$$

$$- m_T \sum_k \beta_i{}^*{}_{T+k-t} /(1+r)^{T+k-1} \quad \{ XS_{it}^* \}$$

where the summation ranges from $k=1$ to $T+1-t$.

Similarly, the effective in-ground price of future existing reserves shut-in less their scrap value cannot exceed the current inground price of shut-in reserves. A shut-in of reserves will only occur in the current period if the value of the resource is at least as large as the value derived from future shut-in resources:

$$(16) \quad \sum_k \beta_{ltk} d_{l\,t+k-1} - d_{l\,t} \leq (m_T - x_l) \sum_k \beta_{l\,T+k-t} /(1+r)^{T+k} \qquad \{ XS_{lt} \}$$

where the summation ranges from k=1 to T-t.

Third, the demand price for oil cannot exceed the current inground price of existing reserves shut-in plus their extraction cost. Production from existing reserves occurs when the demand price covers these opportunity costs:

$$(17) \quad q_t - d_{lt} \leq x_l /(1+r)^t \qquad \{ X_{lt} \}$$

Last, the final demand price for oil cannot exceed the world import price for oil. Imports arise when the prices are equated:

$$(18) \quad q_t \leq m_t /(1+r)^t \qquad \{ M_t \}$$

The primal–dual form of the objective function is derived by subtracting from (1) the following expression :

$$(19) \quad \sum_l \sum_t e_l E_{lt} /(1+r)^t + \sum_l \sum_t d_{lt} D_{lt} + \sum_l \sum_t d_{lt}{}^* D_{lt}{}^* + \sum_l \sum_t y_{lt} Y_{lt}$$

where the first term represents exploration costs and development costs (assumed predetermined in this case), the second and third terms refer to deliverability costs and the last term represents the scarcity costs of new discoveries.

To convert the Rowse model, based on a social welfare objective function, to a model using a net social revenue objective function, the sum of the integrals of the inverse demand functions are replaced by gross revenue, that is, term A in equation (1) becomes:

$$(20) \quad \sum_t F_{at}(Q_t) Q_{at} / (1+r)^t$$

Model Parameters

The model parameters used in the simulation exercise are given in Table 2. The parameters are separated into fixed and variable categories. Fixed parameters have common values across all the simulations. Six simulations, described in the next section, were performed to analyse some of the model's properties.

Fixed parameters

The deliverability constraints, or production limits, on existing reserves are merely a set of illustrative projections of production from existing reserves. The values are broadly consistent with the supply projections in ABARE (1989). These projections correspond to the projections of the Bureau of Mineral Resources at the 50 per cent probability level. The derivation of the production profiles is explained in Appendix B. Note that production from new commercial reserves is assumed to lag discovery by 4 years for fixed offshore platforms, 2 years for offshore floating platforms and one year for onshore facilities. The production tail is longest for offshore fixed platforms and shortest for offshore floating platforms. Recovery profiles for existing reserves shut-in are very similar, except that reserves shut-in in period t can potentially recommence supplying the market as early as period t+1 (see Table 2).

As explained in Appendix B, the parameters for the demand equation were econometrically estimated. A scale term was set to calibrate the actual demand outcome to 1989-90 data. Real growth rates in gross domestic product per person were based on a set of assumptions about the future of the Australian economy. The econometric methods and calibration procedures used to determine the fixed parameters in the drilling and discoveries equations are also explained in Appendix B.

Scenario parameters

A range of scenarios was used, to analyse the properties of the model rather than to produce forecast outcomes. Unless otherwise noted, real operating costs are assumed to average $3/barrel (approximate 1989-90 values) and a real interest rate of 5 per cent a year was assumed for the simulations. These two values represent the mid and lower limits, respectively, of the corresponding values considered in Hogan and Thorpe (1990). In addition, since production was assumed to lag discovery, deliverability constraints on new reserves would tend to be limited to conditions of severe domestic supply disruption, and so were not included in the analysis.

TABLE 2

Model Parameters

Fixed parameters

- Deliverability constraints on existing reserves (millions of barrels per year) (D);

  – offshore fixed platforms
  {t=1,...,10: 119, 103, 89, 80, 71, 72, 72, 66, 59, 53}

  – offshore floating platforms:
  {t=1,...,10: 51, 44, 38, 34, 31, 31, 31, 28, 25, 23}

  – onshore:
  {t=1,...,10: 22, 18, 15, 13, 11, 9, 8, 7, 7, 6}

- Production profiles for new reserves; fraction of reserves supplied per year (β^*);

  – offshore fixed platforms:
  {t=1,...,20: 0, 0, 0, 0, 0.0526, 0.1053, 0.1053, 0.1053, 0.1053, 0.0957, 0.0861, 0.0766, 0.670, 0.0574, 0.0478, 0.0383, 0.0287, 0.0191, 0.0096, 0}

  – offshore floating platforms:
  {t=1,..,20: 0, 0, 0.3333, 0.3333, 0.2222, 0.1111, 0,..,0}

  – onshore:
  {t=1,..,20: 0, 0.10, 0.20, 0.20, 0.1667, 0.1333, 0.1, 0.0667, 0.0333, 0..,0}

- Recovery profiles for existing reserves shut-in; fraction of reserves supplied per year (β);

  – offshore fixed platforms:
  {t=1,..,20: 0.0526, 0.1053, 0.1053, 0.1053, 0.1053, 0.0957, 0.0861, 0.0766, 0.670, 0.0574, 0.0478, 0.0383, 0.0287, 0.0191, 0.0096, 0,..,0}

  – offshore floating platforms:
  {t=1,..,20: 0.3333, 0.3333, 0.2222, 0.1111, 0,..,0}

  – onshore:
  {t=1,..,20: 0.10, 0.20, 0.2, 0.1667, 0.13333, 0.1, 0.0667, 0.0333, 0,..,0}

- Demand equation (equation 2)

  – scale term

  $\alpha_t = \alpha\mu_t^{\alpha_4}$ where α = 3.9820 and the profile for real per person gross domestic product is:

  $\mu_t = 1$ if $t = 0$ and

  $\mu_t = \mu_{t-1}(1 + g_t)$ otherwise,
  where g_t = 0.01 if $t = 1$ or
  = 0.015 otherwise.

  – short run price elasticity

  $\alpha_2 = 0.0311$

TABLE 2 (continued)

- short run per capita GDP elasticity
  $\alpha_4 = 0.1907$

- exponent on lagged demand
  $\alpha_3 = 0.7692$

- actual demand in 1989-90 (lagged dependent variable starting value)
  $Q_o = 234.18$ mbbl

- Drilling equation (equation 13)

  - scale term (δ_{0i})
    {i=1,..,3: 61.4439, 19.4141, 143.1082}

  - exponent on price (δ_{1i})
    {i=1,..,3: 0.5, 0.6, 0.4}

  - exponent on per-unit drilling costs (δ_{2i})
    {i=1,..,3: 1.4, 1.8, 0.6}

- Discoveries equation (equation 9)

  - ultimate reserves (millions of barrels) (U_i)
    {i=1,..,3: 229.0, 62.4, 223.0}

  - cumulative drilling starting point (thousand metres) (CE_{i0})
    {i=1,..,3: 1100.7079, 733.8053, 1557.1467}

  - cumulative discoveries starting point (millions of barrels) (CY_{i0}) in 1989-90
    {i=1,..,3: 230.0, 111.5, 62.5}

  - multiplicative discovery factor (γ_{0i})
    {i=1,..,3: 9.0378, 9.0378, 10.3369}

  - exponential discovery factor (γ_{1i})
    {i=1,..,3: 0.002, 0.003, 0.0015}

TABLE 2 (continued)

Scenario parameters

Baseline assumptions (1)

Finding costs (drilling costs) are constant: $e_{it} = 1$;
Real operating costs are constant: $xs_i = x_i^* = \$3$/barrel (1989-90 values);
Constant real discount rate: $r = 5$ per cent a year;

No deliverability constraints on new reserves; $D^*_{it} = \infty$

World crude oil price increases at 2.5 per cent annually in constant (1989-90) US$; division by exchange rates gives following values in constant A$/barrel ($m_t$):

{t=1,..,20: 21.07, 21.89, 22.74, 23.96, 24.90, 25.89, 26.54, 27.20, 27.88, 28.58, 29.29, 30.02, 30.77, 31.54, 32.33, 33.14, 33.97, 34.82, 35.69, 36.58}

Data for scenarios

World price scenarios

(2) As in baseline except for a temporary price spike in 1990-91 of m_1 =27.76

(3) 4.0 per cent annual growth in world crude oil price measured in constant US$ (1989-90) from the same base as in (2); division by exchange rates gives, in constant A$/barrel ($m_t$):

{t=1,..,20: 27.76, 29.26,30.84, 32.96, 34.77, 36.67, 38.14, 39.67, 41.25, 42.90, 44.62, 46.40, 48.26, 50.19, 52.20, 54.29, 56.46,58.72, 61.06, 63.51}

Drilling cost scenario

(4) 3 per cent annual increase in real drilling costs:

$e_{it} = 1.03\ e_{it-1}$; t=1,..,10; i=1,..,3

Operating cost scenario

(5) Real operating costs of \$4/barrel (1989-90 values) for existing reserves:

$xs_i = 4$; i=1,..,3

Interest rate scenario

(6) $r = 8$ per cent a year

For the base simulation a steadily rising world crude oil price was assumed, increasing from $21/barrel in 1990-91 to $29/barrel in 1999-2000 (1989-90 values). The effect of the Iraqi invasion of Kuwait in August 1990 was not included in this simulation; thus, the simulation serves as a benchmark for analysis of supply response to crude oil price changes in the programming model. For simulation 2 a temporary price spike was assumed to occur in 1990-91 as a result of the Middle East supply disruption and adjustment back to the base-case equilibrium price path. In simulation 3 a sustained 4 per cent annual increase in world crude oil prices was assumed, measured in real US$ terms, from the 1990-91 price of simulation 2.

Changes in the drilling cost and operating cost relative to simulation 1 formed simulations 4 and 5, designed to provide a measure of intertemporal and interregional supply responses to cost changes. The effects of a change in the interest rate on supply response in the model was investigated in simulation 6.

Simulation Results

Simulation 1

All the results refer to the forecast interval 1990-91 to 1999-2000. Shut-in resources are implicitly recovered, through the scrap values, in the ten-year period after 1999-2000. Selected regional aggregate simulation results are presented in Tables 3 to 7. The model was solved using the nonlinear programming package MINOS by Murtagh and Saunders (1983).

The results for the base simulation (1) are given in Table 3. The particular parameter settings chosen generate net imports in each period. Hence, the real domestic price of crude oil corresponds exactly to the exogenously set time path for world crude oil price. This feature is evident in all the simulations examined. Indeed, it would be necessary to drastically increase the deliverability limits (determined by existing reserves available and pumping capacity) to achieve a zero net import outcome in any period. This means, in general, that the supply side of the model is effectively independent of the demand side, and that the supply side effectively amounts to a linear programming subproblem. The demand for petroleum products is influenced only by the real world oil price, per capita gross domestic product per person and lagged demand. Net imports are determined residually as excess demand for petroleum products. It is the level of net imports that is the focus of interest, along with the level of consumption.

In the base simulation the domestic demand for petroleum products rises steadily from 241 mbbl in 1990-91 to 257 mbbl in 1993-94 and reaches 276 mbbl in 1999-2000. The corresponding ABARE (1989) projections were 234 mbbl in 1990-91, 255 mbbl in 1993-94 and 289 mbbl in

TABLE 3

***Selected Simulation Results for Base Run*(a)**

Year	Price for oil (1989/90 prices)	Domestic demand	Domestic supply	Imports	Production in region 1	Production in region 2	Production in region 3
	q	Q	$Q-M$	M	$TS1$	$TS2$	$TS3$
	\$A/bl	mbbl	mbbl	mbbl	mbbl	mbbl	mbbl
1990-91	21.1	241.2	192.0	49.2	119.0	51.0	22.0
1991-92	21.9	247.2	167.2	80.0	103.0	44.0	20.2
1992-93	22.7	252.3	155.0	97.3	89.0	45.0	21.1
1993-94	24.0	256.6	149.6	107.0	80.0	47.6	21.9
1994-95	24.9	260.4	143.6	116.8	74.3	48.3	20.9
1995-96	25.9	263.8	149.0	114.8	81.6	48.9	18.6
1996-97	26.5	267.0	149.4	117.5	86.7	46.4	16.4
1997-98	27.2	270.0	138.7	131.4	84.4	40.5	13.7
1998-99	27.9	272.9	126.4	146.5	79.8	34.7	11.8
1999-20	28.6	275.8	113.8	162.0	74.7	30.2	8.9

(a) The total supply variables TS_i are values of $X_{it} + \sum_k \beta_i{}^*_{t-k+1} \; XS_{ik}^*$ from equation (5).

1999-2000. In the model, the total domestic supply of crude oil and condensate is calculated to fall from 192 mbbl in 1990-91 to 114 mbbl in 1999-2000. Production falls steadily to 144 mbbl in 1994-95, but there is a temporary pick-up in supply to 149 mbbl in 1995-96 and 1996-97. ABARE (1989) projections from the 50 per cent probability projections of the Bureau of Mineral Resources indicated supply dropping from 197 mbbl in 1990-91 to 122 mbbl in 1999-2000, with a temporary plateau of 142 mbbl in the period 1993-94 to 1996-97. Except for 1995-96, the model predicts a fairly steady increase in net imports, from 49 mbbl in 1990-91 to 162 mbbl in 1999-2000. ABARE (1989) projections had imports rising from 37 mbbl in 1990-91 to 167 mbbl in 1999-2000. A very recent set of projections provided by the Bureau of Mineral Resources (ABARE 1991) gives a much more optimistic supply picture. However, these new projections are unlikely to change the conclusions of the study in relation to the performance of the model, since the simulations are evaluated relative to a base scenario.

In simulation 1, all the deliverability constraints on existing reserves prove to be binding and there are no shut-in reserves. Existing reserves comprise the main part of domestic supply over the forecast period. Offshore production from fixed platforms is the largest source of existing supply. Based on the parameters of the logistic growth curves, total commercial discoveries over the forecast period amount to 229 mbbl for region 1, 112 mbbl for region 2 and 62 mbbl for the onshore region. All the constraints on commercial discoveries prove binding. Hence, the results for commercial reserve additions correspond to the calibrated inputs for commercial and non-commercial discoveries. For example, drilling in 1990-91 gives discoveries which ultimately supply 63 mbbl, 21 mbbl and 22 mbbl in regions 1 to 3 respectively. These results are, however, only illustrative. There is considerable geological uncertainty surrounding forecasts of reserves. Stochastic simulation could be used to produce probabilistic forecasts of reserves and of production from these reserves. For example, from the econometric results, probability distributions for discoveries could be generated and randomly sampled.

In the model, the supply outcomes for new reserves are determined from the commercial discoveries figures and the exogenous production profiles. The minimum time lag between discovery and production is one year, which applies to onshore discoveries. Production in 1990-91 is solely from existing reserves. Onshore production is the only source of new supplies in 1991-92. From 1992-93 to 1996-97 offshore production from floating platforms is the main source of new supply, and for the remainder of the forecast interval production from offshore fixed platforms takes over.

If the crude oil price net of operating costs is always positive (as, in reality, it usually is), it follows that the deliverability limits on existing reserves will always be binding, and hence that the scarcity values of these reserves are strictly positive. With the deliverability constraints binding for each region, current-period output equals supplies from the previous shut-in resources plus current exogenous production limits. Current-period production potential will not be shut-in if the scarcity value of current production equals the weighted sum of its future scarcity values inclusive of the scrap value (the weights being taken from the recovery profile for shut-in reserves). The scrap value corresponds to the net price of what remains shut-in at the forecast horizon.

Given the assumed values for the model parameters, no existing reserves are ever shut-in in the base simulation. Thus, in this simulation deliverability constraints are fully met by current production. There is always production from existing reserves in each region, and since operating costs were assumed to be common it follows that the scarcity values of existing reserves are always equal across all regions. That is, the real price gap, in undiscounted 1989-90 values, between the world price and the scarcity value on existing reserves corresponds to the constant operating costs.

There are differences in the scarcity values for new reserves, both across regions and over time. New commercial discoveries — that is, new reserves for which production is booked or committed for supply — correspond to actual discoveries if the intertemporal arbitrage condition is satisfied. In particular, this constraint is binding if the current scarcity value of new reserves equals the profile-weighted sum of future world crude oil prices, over the forecast horizon, plus the scrap value of these new reserves.

From the exogenous time paths for crude oil price and operating costs, it follows that the current scarcity values for new reserves are always strictly positive, so that the constraints on new reserves are binding. The scarcity values are smallest in region 1 since, while scrap values tend to be largest in region 1 because of the long production tails, this is more than offset in the base simulation by the long lead times and low production rates in this region. Floating platforms have the highest scarcity values early in the forecast period because of their heavy weighting on fast extraction.

Simulation 2

All results are compared to the base case simulation (1) unless otherwise stated.

Except through the exogenously determined world oil price, the demand side of the model is independent of the supply side of the model. As shown in Table 4, the temporary price rise in 1990-91 leads to a slight decrease in demand for petroleum products relative to simulation 1. The

TABLE 4

Selected Simulation Results for Simulation 2: Price spike in 1990-91(a)

Year	Price for oil (1989/90 prices)	Domestic demand	Domestic supply	Imports	Production in region 1	Production in region 2	Production in region 3
	q	*Q*	*Q–M*	*M*	*TS*1	*TS*2	*TS*3
	$A/bl	mbbl	mbbl	mbbl	mbbl	mbbl	mbbl
1990-91	27.8	239.2	192.0	47.2	119.0	51.0	22.0
1991-92	21.9	245.6	167.4	78.2	103.0	44.0	20.4
1992-93	22.7	251.0	156.6	94.4	89.0	46.2	21.5
1993-94	24.0	255.6	150.9	104.7	80.0	48.7	22.2
1994-95	24.9	259.6	144.6	115.0	74.8	48.8	21.0
1995-96	25.9	263.2	149.7	113.5	82.4	48.8	18.5
1996-97	26.5	266.5	149.4	117.1	87.3	45.8	16.3
1997-98	27.2	269.6	138.4	131.3	84.8	40.0	13.6
1998-99	27.9	272.6	126.0	146.6	80.1	34.3	11.7
1999-2000	28.6	275.6	113.3	162.3	74.8	29.8	8.7

(a) See Table 3.

demand contraction in 1990-91 is 2 mbbl; reflecting lagged quantity adjustment, demand gradually moves back to the path of simulation 1.

As modelled, the temporary spike in the crude oil price increases concurrent drilling effort in 1990-91. Commercial reserves in 1990-91 rise by 9 mbbl, 4 mbbl and 2 mbbl in regions 1, 2 and 3, respectively, relative to simulation 1. However, the higher base of the logistic discoveries curve results in earlier diminishing returns to drilling effort than in simulation 1. Hence, from year 2 (1991-92) onward there are marginal reductions in the finding success rate (reserves added relative to extra drilling effort) compared with the base-case simulation. As expected, the scarcity values for new reserves are unchanged from the base case, as they depend on prices from year 2 onward. Reflecting changes in discoveries, aggregate supply from new reserves is slightly higher than in the base case between 1991-92 and 1995-96, but slightly less over the remainder of the forecast interval.

Supplies from existing reserves are unaffected by the temporary price shock. This is because there is only a small increase in the scarcity value of existing reserves, which is confined to 1990-91. Knowledge of future prices feeds into the scrap values, which feed back to earlie scarcity values. In this simulation prices beyond 1990-91 are unchanged from the base case.

Overall, net imports decline slightly relative to simulation 1, except in the last three years of the forecast period where they are virtually unchanged. Net imports are around 2 mbbl lower in the first five years of the forecast period.

Simulation 3

Results for simulation 3 are shown in Table 5. A higher growth path in the real world oil price has dramatic effects on production from existing reserves, aggregate demand and net imports, and more moderate effects on commercial discoveries and production from new reserves. The striking feature of this simulation is that the high output price path causes all existing offshore production on fixed platforms to be shut-in throughout the ten-year forecast interval. However there are no shut-in reserves in regions 2 and 3.

Large increases in the scarcity values of existing reserves are generated. The effects are most marked for the reserves in region 1. The opportunity cost of current depletion in region 1 in 1990-91 is around $7/barrel higher than the scarcity values in regions 2 and 3 (in 1989-90 dollars). Production profiles for reserves shut-in are longest in region 1, and since price rises are largest toward the end of the forecast horizon, scrap values are greatest for production from offshore fixed platforms. From the arbitrage conditions, large scrap values at the horizon are

TABLE 5

***Selected Simulation Results for Simulation 3: Sustained price rise*(a)**

Year	Price for oil (1989/90 prices)	Domestic demand	Domestic supply	Imports	Production in region 1	Production in region 2	Production in region 3
	q	*Q*	*Q–M*	*M*	*TS*1	*TS*2	*TS*3
	$A/bl	mbbl	mbbl	mbbl	mbbl	mbbl	mbbl
1990-91	27.8	239.2	73.0	166.2	0.0	51.0	22.0
1990-92	29.3	243.4	64.4	179.0	0.0	44.0	20.4
1992-93	30.8	246.9	67.8	179.1	0.0	46.2	21.6
1993-94	33.0	249.9	72.4	177.5	0.0	49.9	22.5
1994-95	34.8	252.5	75.9	176.6	3.8	50.8	21.3
1995-96	36.7	254.9	80.2	174.6	10.8	50.8	18.7
1996-97	38.1	257.1	79.6	177.5	16.2	47.2	16.3
1997-98	39.7	259.2	73.6	185.7	19.8	40.3	13.5
1998-99	41.3	261.3	67.2	194.1	21.9	33.8	11.5
1999-2000	42.9	263.3	59.8	203.5	22.4	28.9	8.5

(a) See Table 3.

reflected back to the early scarcity values, particularly affecting the earliest years. Shut-in reserves are therefore signalled in the model.

The shutting-in of resources in region 1, and not elsewhere, implies that reserves in regions 2 and 3 are used first because their production profiles are shorter and extraction rates are higher than in region 1. However, there is a price threshold beyond which these reserves would also be shut-in.

The results for existing reserves are driven by the choice of objective function and the assumption of perfect foresight. It makes some sense to shut-in new reserves and wait for higher prices. However, the effects generated are so large as to be rather implausible. For the model's objective function to have realism, it would have to be assumed that the government decides to buy all the reserves shut-in. Companies simply could not afford to wait out ten years before receiving any cash flow. In addition, there is considerable uncertainty surrounding future prices and costs. The price trend of simulation 3 would be likely to be attended with a high risk, but the objective function does not reflect this problem. It would appear that at the very least the model should have a penalty term for risk associated with shut-ins, since the actual costs of shutting-in resources should be considered, and that stochastic simulation is required to determine more plausible effects.

In addition, the notion that firms have such long term views as are assumed here, and optimise over long time horizons, may not be realistic. Instead, it could be argued that optimisation occurs in two stages: that firms first make decisions with a short term view (say, five years) which may either be realised or not, and then revise their plans every one-to-three years, with a rolling planning horizon. This sort of optimisation strategy could be built into the programming model, and would be likely to moderate the shut-in behaviour shown here.

As in simulation 2, commercial discoveries in 1990-91 are increased by 9 mbbl, 4 mbbl and 2 mbbl in the three regions, relative to simulation 1. However, because the price increase is sustained, reserve additions increase more rapidly in the early years, before finding rates decline, than in the base case. The results for production from new reserves reflect the changes in new discoveries. Production in region 1 is uniformly higher throughout the forecast period. For region 2 production is greater than in simulation 1 for the first seven years of the forecast period, and slightly lower in the last three years. For region 3, the switch point when production becomes lower than in simulation 1 occurs in year 7. Overall, total production from new reserves is higher in simulation 3 throughout the forecast period except in 1998-99 and 1999-2000.

Compared with the base case, demand is 2 mbbl lower in 1990-91, and this gap increases steadily to 12 mbbl by 1999-2000. As in the simulations above, net imports rise throughout the forecast period. In 1990-91 imports are 117 mbbl higher than in the base case, but the difference falls steadily to 41 mbbl by 1999-2000.

Simulation 4

When domestic crude oil prices are determined solely by world prices, supplies from existing reserves are unrelated to supplies from new reserves. Consequently, the results from a 3 per cent per year increase in real drilling costs, as shown in Table 6, are hardly surprising. The only quantities which change relative to simulation 1 are commercial discoveries and production from these new reserves. In region 1, reserves are lower than in the base case for the first four years and higher for the last six years. Basically, diminishing returns implied by the logistic curve set in more slowly when there is less drilling effort. In region 2, the same pattern emerges except that the switch point is in year 8. By 1999-2000, 3 mbbl less crude oil and condensate are discovered in region 1, and 6 mbbl less in region 2, than in the base case. The effect on commercial reserves discovered onshore within the forecast horizon is negligible. This result reflects the relatively low price elasticity of drilling demand.

The model's structure and the parameter choice do not allow scarcity values of new reserves to change as drilling prices change. Reflecting the changes in new reserves, production from all offshore facilities declines in all years relative to the base case, but that from onshore facilities hardly changes at all. Because of reduced aggregate domestic supply, net imports are higher than in the base case.

Simulation 5

Effects of an increase in the operating costs of production from existing reserves, from $3/barrel to $4/barrel in 1989-90 values, are shown in Table 7. The model's structure dictates that, when net imports are strictly positive, the change in operating costs has no effects on new discoveries or on production from these discoveries. The scarcity value of production from region 1 rises relative to regions 2 and 3. Basically, the increase in costs results in a tendency to suspend production until the more heavily discounted future. This tendency is realised in region 1 because of the long lead times and long production tails associated with the technology in region 1. However, while some production in region 1 is shut-in, production paths for existing reserves in regions 2 and 3 are unchanged from the base case. Reflecting intertemporal arbitrage, around 119 mbbl, 109 mbbl and 107 mbbl of crude oil and condensate are shut-in in region 1 over the first three years and another 88 mbbl in 1999-2000. These shut-ins facilitate greater output in

TABLE 6

***Selected Simulation Results for Simulation 4: Real drilling costs rise*(a)**

Year	Price for oil (1989/90 prices)	Domestic demand	Domestic supply	Imports	Production in region 1	Production in region 2	Production in region 3
	q	Q	$Q-M$	M	$TS1$	$TS2$	$TS3$
	$A/bl	mbbl	mbbl	mbbl	mbbl	mbbl	mbbl
1990-91	21.1	241.2	192.0	49.2	119.0	51.0	22.0
1991-92	21.9	247.2	167.1	80.0	103.0	44.0	20.1
1992-93	22.7	252.3	154.6	97.7	89.0	44.6	21.0
1993-94	24.0	256.6	148.4	108.2	80.0	46.7	21.8
1994-95	24.9	260.4	141.7	118.7	74.2	46.8	20.8
1995-96	25.9	263.8	146.6	117.2	81.1	47.0	18.5
1996-97	26.5	267.0	146.9	120.1	85.9	44.6	16.3
1997-98	27.2	270.0	136.5	133.6	83.5	39.2	13.8
1998-99	27.9	272.9	124.8	148.1	78.9	34.0	11.9
1999-2000	28.6	275.8	112.9	162.9	73.9	30.1	9.0

(a) See Table 3.

TABLE 7

Selected Simulation Results for Simulation 5: Real operating costs rise(a)

Year	Price for oil (1989/90 prices)	Domestic demand	Domestic supply	Imports	Production in region 1	Production in region 2	Production in region 3
	q	*Q*	*Q–M*	*M*	*TS*1	*TS*2	*TS*3
	$A/bl	mbbl	mbbl	mbbl	mbbl	mbbl	mbbl
1990-91	21.1	241.2	73.0	168.2	0.0	51.0	22.0
1991-92	21.9	247.2	64.2	183.0	0.0	44.0	20.2
1992-93	22.7	252.3	66.0	186.3	0.0	45.0	21.1
1993-94	24.0	256.6	179.2	77.4	109.7	46.7	21.9
1994-95	24.9	260.4	178.9	81.5	109.6	48.3	20.9
1995-96	25.9	263.8	184.3	79.5	116.9	48.9	18.6
1996-97	26.5	267.0	183.6	83.4	120.9	46.4	16.4
1997-98	27.2	270.0	170.7	99.4	116.4	40.5	13.7
1998-99	27.9	272.9	67.4	205.5	20.8	34.7	11.8
1999-2000	28.6	275.8	144.0	131.8	104.9	30.2	8.9

(a) See Table 3.

years 4–8 and year 10 relative to the base case. Consequently, while net imports are larger than in the base case in years 1–3 and year 9 they are smaller in years 4–8 and year 10.

Simulation 6

An increase in the real interest rate of 3 percentage points leaves all quantities unchanged from their base-case values. The scarcity values of existing reserves (in undiscounted 1989-90 dollars) fall relative to the base-case. The scarcity values for offshore reserves in 1990-91 and 1999-2000 are around $6/barrel below the base case values; those for regions 2 and 3 are also reduced, but by less. With lower scarcity values, production in the earlier years would be encouraged if the deliverability constraints were not already binding.

Directions for Further Research

There are a number of areas where refinement of the model is warranted. First, in the current model the existence of net imports in each period (which in itself is realistic) means that the domestic price of crude oil and condensate always equals the exogenously set world price. Hence, domestic demand for petroleum products and domestic supply of crude oil and condensate are independent, with net imports following residually. With costs also exogenously set, supplies from existing reserves and supplies from newly discovered reserves are also independent. A modification which would allow more of the actual price linkages (feedbacks) to be represented in the model would be to disaggregate demand into primary and refined product and to model the production and distribution chain to end use, with domestic and foreign product as imperfect substitutes.

Second, the modelling of production from existing reserves and of the associated shutting-in of resources seems somewhat unrealistic. While it is possible that in practice some reserves may be shut-in, this tendency is far too strong in the model. In the simulation results, when deliverability constraints are binding and the real crude oil price is shifted to a higher path (of which producers have fore-knowledge) there is a significant tendency to shut-in existing offshore reserves. It can readily be shown that even for extremely large values for domestic production, such that net imports disappear and price becomes endogenous, the model predicts shut-in resources and switching of production to a sole regional source of supply for an extended period of time. In fact, the scope for this kind of action on the part of private firms would seem to be limited. For government, this sort of stockpiling behaviour could be optimal, but even then there would be considerable risk of economic loss if predictions regarding the oil price proved to be wrong.

One way to modify this stockpiling feature of the model would be to include a risk penalty component in the objective function which would discourage excessive stockpiling behaviour. Another way is to disallow shut-in resources altogether and include a production profile for existing reserves much like that for new reserves. It would still be assumed that these sources of supply were perfect substitutes. This would force endogenous links between new and old sources of supply which are not included in the arbitrage conditions of the Australian version of the Rowse model. Rising regional operating cost schedules or regional reserves limits would also have to be specified.

Moreover, the notion that oil firms pursue rather more myopic optimisation strategies needs to be considered. For example, it could be argued that firms base decisions on short to medium term expectations of the paths of input and output prices, and revise their plans every one-to-three years. The inclusion in the model of this type of behaviour, with the possibility of rolling planning horizons, could add realism and would be likely to moderate the extreme shut-in behaviour currently present.

Third, the fact that drilling effort and cumulative commercial discoveries have only exogenous influences on the model is of some concern. This limitation might be addressed by substituting the domestic price for the world crude oil price in the drilling effort equation. With respect to the nonlinear optimisation routine used, this option would require incorporation of the primal equations for drilling and discoveries and corresponding changes to the dual constraints. While the primal version of this model could be solved with endogenous drilling and discoveries variables, the primal–dual version could not be correctly solved in the sense of producing an objective function of zero. Further work is required to determine an appropriate model form in this area.

If demand disaggregation, as indicated above, were used then an endogenous price link connecting production from new reserves with production from old reserves could be included, but this influence is not likely to be particularly strong. That is, old reserves will always be used before production from new reserves. More important is the fact that there is considerable geological uncertainty regarding new discoveries. At the very least, a probabilistic approach is required to address these uncertainties. Probability distributions could be used to project confidence intervals for discoveries, and Monte Carlo model simulation could be performed. Alternative functional forms to the logistic growth curve could also be considered. In addition, the drilling equations could be disaggregated into exploration and development components and different lagged price responses investigated.

APPENDIX A

Variable List

This appendix contains a list of the variables used in the model along with the definitions for most of the parameters. Note that capital letters represent quantities and lower case letters prices. Greek symbols are used for parameters.

Endogenous variables

Q_t = domestic consumption of petroleum product in year t
q_t = consumer price of oil in year t
X_{it} = domestic supply of oil from existing reserves in region i and year t
XS_{it} = existing reserves shut-in in region i and year t
XS_{it}* = new reserves committed for supply from region i in year t
M_t = imports of petroleum product from abroad in year t
d_{it} = shadow value on existing reserves shut-in in region i and year t
d_{it}* = shadow value on new reserves left in the ground in region i and year t
y_{it} = scarcity value on new discoveries in region i and year t

Exogenous variables

r= the interest rate
x_i = unit extraction cost for existing reserves in region i
x_i* = unit extraction costs for new reserves in region i
xs_i* = discounted unit extraction cost for new reserves in region i
e_{it}* = unit cost of finding effort in region i in year t
m_t = world import price for oil in year t
D_{it} = deliverability constraint on production from existing reserves in region i and year t
D_{it}* = deliverability constraint on production from new reserves in region i and year t
Y_{it} = commercial plus non-commercial reserves in region i as of year t
CY_{it} = cumulative commercial plus non-commercial reserves in region i as of year t
E_{it} = exploration and development effort in region i and year t
CE_{it} = cumulative finding effort in region i and year t

Parameters

α_{1t} = shift parameter on the inverse domestic demand function in year t
α_2 = short run price elasticity of domestic demand for petroleum products
α_3 = elasticity coefficient on the lagged domestic demand
α_4 = elasticity coefficient on real per capita gross domestic product
β_{it} = fraction of shut-in oil recovered in region i and year t
β_{it}^* = fraction of newly discovered oil produced in region i and year t
U_i = maximum potential total discoveries in region i
γ_{0i} = term from logistic cumulative discoveries curve in region i and year t
γ_{1i} = term from logistic cumulative discoveries curve in region i and year t
δ_{0i} = shifter for domestic finding effort curve in region i and year t
δ_{1i} = output price elasticity of domestic finding effort in region i
δ_{2i} = input price elasticity of domestic finding effort in region i

APPENDIX B

Data for the Programming Model

In this appendix the production profiles used in the model and the equations estimated for domestic demand, drilling effort and cumulative discoveries are described.

Crude oil and condensate supply profiles

The assumed crude oil and condensate supply profiles from new discoveries are very similar to the recovery profiles for pre-existing reserves shut-in. Production from newly found reserves lags discoveries in all three production regions. If a discovery is made in year 1, production commences t_1 years later. For offshore fixed platforms $t_1=4$, for offshore floating platforms $t_1=2$ and for onshore fields $t_1=1$. For shut-in oil it was assumed that $t_1=1$ for all production technologies. This is the one essential difference between the supply profiles for new reserves and the recovery profiles for shut-in reserves.

The production profiles for new and pre-existing discoveries are based on Hogan and Thorpe (1990). For onshore fields and offshore fields with fixed platforms the production profile is as given in Figure 1. There is a short rising linear segment followed by a plateau level of production and then a linear tail to zero output. In the case of offshore floating platforms production commences at the plateau level.

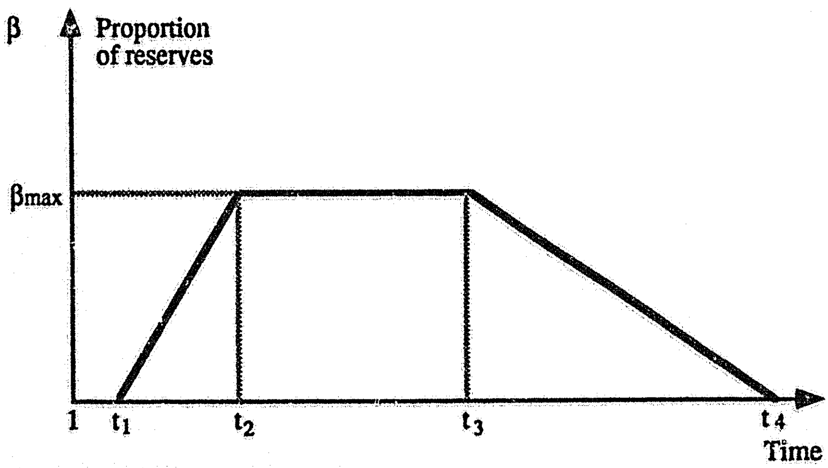

FIGURE 1 — ***Illustration of a production profile***

The time required from first production until plateau production is t_2-t_1. For both offshore fixed platforms and onshore fields t_2-t_1-1=1. Plateau production was assumed to last t_3-t_2 years. For offshore fixed platforms plateau production is assumed to last 4 years, and for the two other technologies 2 years. The production tail lasts t_4-t_3 years. For offshore fields with fixed production platforms production ceases in year 20, for floating platforms in year 7 and for onshore fields in year 10.

The formula for a crude oil and condensate supply profile is assumed to be:

$$
\begin{aligned}
\text{(B.1)}\quad \beta &= 0 \text{ for } t = 1 \text{ to } t_1 \\
&= \beta_{max}(t-t_1)/(t_2-t_1) \text{ for } t = t_1 + 1 \text{ to } t_2 - 1 \\
&= \beta_{max} \text{ for } t = t_2 \text{ to } t_3 \\
&= \beta_{max}(t-t_4)/(t_3-t_4) \text{ for } t = t_3 + 1 \text{ to } t_4 - 1
\end{aligned}
$$

where β is the proportion of reserves produced annually and β_{max} is the peak share of reserves produced. The value for β_{max} is determined such that the sum of the β values is unity — that is, all reserves are exhausted. The values derived from these profiles are given in Table 2 of the main text.

Aggregate domestic demand for petroleum products

Econometric estimates

Short and long run price and real per-person income elasticities of Australian aggregate demand for petroleum products are basic inputs in the programming model. A log-linear partial stock adjustment model was used to explain aggregate domestic demand for petroleum products. A log-linear form was chosen because computed elasticities are then constant and invariant to the unit of measurement. A partial adjustment form was chosen as it implies the reasonable assumption that demand cannot adjust immediately to its desired value, and because it permits joint estimation of both short and long run elasticities.

The dependent variable, aggregate demand for petroleum products, was defined as domestic production of crude oil and condensate plus net imports of petroleum products less petroleum refining fuel use and losses. This regressand represents petroleum products available including all end-use sectors and non-refinery conversion sectors. This variable was chosen for consistency with the programming model and implies an assumption that the rest-of-world and domestic crude oil and condensate production and refined petroleum products are all perfect substitutes.

The explanatory variables included in the model were an index of domestic crude oil prices relative to the consumer price index, real per-person gross domestic product and the lagged dependent variable. The consumer price index was used in the relative price term because transport use is the main source of domestic petroleum demand. Private and commercial use of petroleum products were assumed to mainly reflect demand for consumer goods and services. Real gross domestic product per person was used to proxy real income per person.

The sample period for the regression was 1965-66 to 1988-89. All real variables are in 1984-85 values. The model was estimated using the DATAFIT regression package. The data set and sources for the least squares regression are given in Table B.1, and the results for parameter estimates and diagnostic tests on the model are reported in Table B.3.

From Durbin's h-test and a Lagrange multiplier test, the assumption of non-autocorrelated errors was not rejected. From Ramsey's RESET test there is no evidence of functional form misspecification. In the Jarque-Bera test, normality of regression residuals was not rejected. The homoscedasticity assumption also was not rejected by a Lagrange multiplier test. From a cusum of squares plot there was no evidence of structural instability. The model passed Chow's predictive failure test over the last four periods in the dataset.

From the parameter estimates, the short run price elasticity of demand for petroleum products was estimated to be -0.03, and the long run elasticity -0.13, both significantly different from zero at the 5 per cent level of significance. These results broadly conform with earlier studies surveyed by the Department of National Development and Energy (1981). The elasticity with respect to real per-person gross domestic product was estimated to be 0.19 in the short run, and in the long run 0.83.

Calibration of the model functions

To align the various estimated functions on a suitable starting point, namely 1989-90, various adjustments were made to the functions. This process will be referred to as calibration.

The log-linear demand equation was implemented in the programming model in an inverse form (equation (2)):

$$\text{(B.2)} \quad q_{at}(Q_t) = (\alpha_{1t}\, Q_{t-1}{}^{\alpha_3} / Q_t)^{1/\alpha_2}$$

where α_{1t} is a collapsed intercept calculated to grow over time as follows:

(B.3) $\alpha_{1t} = \alpha \, \mu_t^{\ \alpha_4}$

and the profile for real per person gross domestic product was assumed to be

$$\mu_t = 1 \text{ if } t = 0 \text{ and}$$
$$\mu_t = \mu_{t\text{-}1} (1 + g_t) \text{ elsewhere,}$$

where g_t is the growth rate for real per person gross domestic product.

The demand equation was calibrated to the most recent actual outcome for demand in 1989/90. In particular, α was set at:

(B.4) $\alpha = Q_0 \, q_0^{\alpha_2} / Q_{-1}^{\alpha_3}$

wher.:

Q_{-1} = 226.26 mbbl in 1988/89

Q_0 = 234.18 mbbl in 1989/90

q_0 = \$21.95/barrel in 1989/90

α_i = the corresponding econometric estimate from table B.3; i = 2, 3.

This procedure gave α = 3.9820.

Drilling effort

Econometric estimates

Elasticities for drilling effort were required for developing the resource availabilities in the programming model. Drilling activity is a major component of set-up costs — that is, of the costs of finding and developing oil reserves and establishing production. Decisions to undertake exploration and development drilling are potentially sensitive to the real price of crude oil and real input costs. It was also hypothesised that drilling effort is influenced by the success rate of production. Separate equations were estimated for onshore and offshore facilities. Data limitations prevented separate estimation for fixed and floating offshore facilities.

A log-linear functional form was used to descrive drilling behaviour. The dependent variable, drilling effort, was measured in metres drilled in finding and developing crude oil and condensate reserves. The explanatory variables used were an index of real domestic crude oil prices, real average set-up costs per metre drilled (representing input prices) and the production (success) rate per metre drilled. Nominal oil prices were deflated by the consumer price index, while per unit set-up costs were deflated by the gross domestic price deflator. The indexes have a base of 1984=100.

The crude oil price was included to reflect the firm's ultimate supply objective. The a priori sign on this term was positive. Per-unit set-up costs were used to proxy the composite price of all inputs required to establish production, and were expected to be negatively related to metres drilled. It was expected that as the production success rate rose the need to drill more to replace depleted reserves was likely to diminish. Production per metre was measured at the aggregate rather than the regional level of supply.

The sample period for all drilling effort regressions was 1972 to 1988. The dataset and sources for all regressions are given in Table B.2. The drilling equations were estimated using the DATAFIT regression package. The preferred least squares results for onshore and offshore regions are reported in Table B.3.

The results for onshore drilling effort have the correct a priori signs. Drilling effort was positively related to the output price and negatively related to the average set-up costs and production per metre. The drilling supply response to output and input prices is, however, relatively inelastic. The price elasticity is in the region of 0.5 and the elasticity of drilling effort with respect to the production success rate is approximately -0.8. While the Durbin–Watson test was indeterminate, the Lagrange multiplier test supported serial independence. All other reported diagnostics were acceptable and there was no evidence of a structural break in a cusum of squares plot.

For offshore drilling effort, preliminary data analysis indicated a possible structural break in the equation around 1981. This is broadly consistent with a lagged response to the second oil price shock in the late 1970s. Consequently, a dummy variable was introduced with a value one for 1972-80 and a value zero elsewhere. An auxiliary regression with dummy variables for slopes and intercept was run. Variables with insignificant t-ratios were then eliminated to determine the preferred equation. On this basis the production success rate was dropped from the regression. The standard diagnostics from this equation were acceptable. Offshore drilling effort appeared to be statistically more sensitive to input and output prices in the post-1980 period. In the later period the input price elasticity was close to -1.5 while the output price elasticity was close to 0.5.

Calibration

The log-linear drilling equations were used in a nonlinear form (equation 13):

(B.5) $E_{it} = \delta_{0i}\ m_t^{\ \delta_{1i}} / e_{it}^{\ \delta_{2i}}$

Note that production per metre is absent from (B.5). Though production per metre was a significant influence onshore, it was assumed that it would be stable throughout the simulation period.

The drilling equations were calibrated to actual offshore and onshore metres drilled in 1989/90. Based on estimates of the Australian Petroleum Exploration Association (1990) in 1989/90 some 403 000m and 484 400m were drilled offshore and onshore, respectively. It was arbitrarily assumed that 70 per cent of the offshore result pertained to region 1. Hence (in '000m), in 1989/90 $E_1 = 282.1$, $E_2 = 120.9$ and $E_3 = 484.4$. It was assumed that $\delta_{11} = 0.5$, $\delta_{12} = 0.6$ and $\delta_{13} = 0.4$. With real costs per metre normalised to unity, calibration required solving (B.5) for δ_{0i}. Using a value for the import price of $m_0 = 21.08$, this resulted in values of $\delta_{01} = 61.4$, $\delta_{02} = 19.4$ and $\delta_{03} = 143.1$.

New discoveries

Econometric estimates

Reinsch and O'Reilly (1990) used a modified Hubbard rate-of-effort model to link discoveries with drilling effort. Following their approach, a logistic growth curve was used in the programming model to describe cumulative discoveries as a function of cumulative drilling effort. This equation was separately estimated for onshore and offshore regions. The functional form of the logistic curve is (equation (9)):

(B.6) $CY_{it} = U_i / [1.0 + \gamma_{0i} \exp(-\gamma_{1i}\ CE_{it})]$

where the γ_{ji}'s and U_i are parameters to be estimated. Note that U_i is an estimate of the potential aggregate discoveries in region i.

As Reinsch and O'Reilly (1990) note, this form is consistent with an initial learning period in the discovery process, during which the discovery rate may rise, followed by a period of depletion in which the cumulative discovery effort faces diminishing returns and then a gradual asymptotic tail as discoveries approach total potential reserves.

Data and sources for the two logistic curves are given in Table B.2. Both equations were estimated by non-linear least squares using the TROLL econometric modelling system. Results are reported in Table B.3. They are satisfactory, although the Durbin–Watson statistics are in the indeterminate region. An important input into the model is the estimates of ultimate reserves. In the 17-year period, ultimate onshore discoveries and offshore discoveries are estimated to approximate 125 mbbl and 685 mbbl respectively.

Calibration

In the absence of separate data for regions 1 and 2 it was assumed that ultimate discoveries in region 1 were 460 mbbl. When this assumption is combined with the econometric results, it follows that $U_1{}^e = 460$, $U_2{}^e = 225$ and $U_3{}^e = 125$, where superscript e denotes a starting value as described below. On the basis of the econometric results, it was assumed that $\gamma_{01} = \gamma_{02} =$ 9.0 and $\gamma_{03} = 10.3$. The terms $\gamma_{11} = 0.0023$ and $\gamma_{13} = 0.0015$ were the respective econometric estimates. It was arbitrarily assumed that $\gamma_{12} = 0.003$.

The following procedure was used to determine U_i, the ultimate reserves discoverable from 1990-91 to 1999-2000 in region i. First, it was assumed that, in each region, the maximum total further reserves discoverable from 1990-91 to 1999-2000 were half the econometrically estimated 'ultimate reserves' given above: that is

$$\text{(B.7)} \quad \sum_t Y_{it} = U_i{}^e/2 \ .$$

Second, the path for reserves was made consistent with drilling effort generated under ABARE forecasts of the path for real crude oil prices prior to the Iraqi invasion of Kuwait (see Table 2 of the main text). Third, it was assumed that the point of inflexion was reached on all logistic curves in 1989-90, so that the starting value for cumulative drilling effort was

$$\text{(B.8)} \quad CE_{i0} = \ln(\gamma_{0i}) / \gamma_{1i} \ .$$

The values of U_i were obtained by solving so that U_i satisfies (B.6) to (B.8). The starting values were the $U_i{}^e$ estimates.

For regions 1 and 3 there was no need to modify the U_i estimates, as the $U_i{}^e$ forecasts led to cumulative additions of 229.0 and 62.4 mbbl respectively. For region 2, U_i was modified to 223 mbbl, which resulted in cumulative additions of 112.4 mbbl.

The starting values for cumulative discoveries (mbbl) and cumulative drilling effort ('000m) used in the programming model were therefore $CY_{10} = 230$, $CY_{20} = 111.5$, $CY_{30} = 62.5$; $CE_{10} = 110.7$, $CE_{20} = 733.8$ and $CE_{30} = 1557.1$.

TABLE B.1

Data for Pertroleum Model Demand-side Regressions for Crude Oil and Condensate

Year	Demand quantity(a) QD	Gross domestic product(b) GDP	Population (c) POP	Domestic crude oil price index(d) OILP	Consumer price index (e) CPI
	PJ	$ million	'000		
1964-65	649.80	102510.00	11341.00	6.81	21.79
1965-66	708.50	105331.00	11599.00	8.03	22.59
1966-67	764.50	111867.00	11799.00	8.43	23.18
1967-68	837.70	116970.00	12009.00	8.69	23.98
1968-69	928.50	126200.00	12263.00	8.69	24.58
1969-70	999.80	131301.00	12507.00	8.15	25.36
1970-71	1034.10	140951.00	13067.00	5.79	26.59
1971-72	1084.30	146652.00	13304.00	5.53	28.39
1972-73	1112.00	153172.00	13505.00	5.53	30.10
1973-74	1218.50	160286.00	13723.00	5.53	34.00
1974-75	1215.60	162197.00	13893.00	5.53	39.70
1975-76	1221.30	165937.00	14033.00	10.57	44.83
1976-77	1286.60	170594.00	14192.00	11.62	51.06
1977-78	1310.70	172351.00	14359.00	16.84	55.92
1978-79	1325.70	181374.00	14516.00	32.46	60.50
1979-80	1308.20	185977.00	14695.00	57.06	66.62
1980-81	1261.80	192176.00	14923.00	76.81	72.90
1981-82	1246.80	195677.00	15184.00	84.27	80.48
1982-83	1175.70	192932.00	15394.00	97.68	89.74
1983-84	1215.20	203149.00	15579.00	95.65	95.88
1984-85	1217.00	214288.00	15788.00	100.00	100.00
1985-86	1221.40	223426.00	16018.00	99.06	108.38
1986-87	1227.90	229585.00	16263.00	67.96	118.51
1987-88	1269.70	239588.00	16538.00	67.30	127.17
1988-89	1331.00	247849.00	16807.00	52.17	136.52

(a) Quantity of petroleum products available for consumption by end-use sectors and non-refinery conversion sectors; ABARE (1989). (b) Real gross domestic product in constant 1984-85 prices; Australian Bureau of Statistics, *Timeseries tape*, Cat. no. 1311.0 for series NGDPZ, Canberra. (c) Australian Bureau of Statistics, *Australian Demographic Statistics*, Cat. no. 3101.0, Canberra. (d) Price index of domestic crude oil; Australian Bureau of Statistics, *NIF-10 tape*, Cat. no. 1313.0 for series PGCO, Canberra. (e) Consumer price index for eight state capital cities, and for six state capital cities prior to 1980-81; Australian Bureau of Statistics, *Timeseries tape*, Cat no. 1311.0 for series PC8 and PC, Canberra.

TABLE B.2

Data Used for Petroleum Model Supply-side Regressions

Year	Offshore metres drilled(a)	Onshoree metres drilled(a)	Domestic crude oil price index(b)	Consumer price index	Gross domestic price deflator(c)	Onshore expenditure (d)	Offshore expenditure (d)	Cumulative onshore reserves(e)	Cumulative offshore reserves(e)	Crude oil and condensate production (f)
	OFM	ONM	OILP	CPI	GDPDE	INVON	INVOF	CUONRES	CUOFRES	PROD
	000m	000m				$ million	$ million	mbbl	mbbl	mbbl
1972	141.07	154.37	5.89	29.90	28.55	50.80	111.30	14.19	77.74	119.50
1973	90.26	61.65	5.89	32.72	32.18	30.10	100.90	14.31	114.44	142.30
1974	81.08	52.74	5.89	37.68	38.12	27.90	92.70	15.87	120.39	140.90
1975	35.66	22.93	8.01	43.35	44.37	27.50	107.50	15.87	159.32	150.60
1976	15.12	57.26	12.37	49.21	50.64	45.60	97.20	15.94	164.29	155.90
1977	43.25	68.18	14.40	55.28	55.20	56.20	139.80	19.28	161.29	160.60
1978	99.39	109.04	24.89	59.66	58.08	112.50	214.90	22.07	170.89	168.00
1979	112.74	103.75	45.44	65.07	65.29	99.80	358.90	22.88	237.56	175.50
1980	89.15	178.63	73.59	71.70	71.71	197.70	450.30	23.20	237.56	145.70
1981	79.60	354.86	86.68	78.60	79.52	359.20	1043.30	64.50	254.04	150.90
1982	156.59	478.32	96.06	87.38	89.02	733.90	1476.90	69.56	286.95	142.90
1983	223.84	355.59	105.87	96.20	92.31	690.10	1055.70	82.68	448.87	159.20
1984	251.13	550.62	100.00	100.00	100.00	584.90	889.60	98.84	524.15	190.80
1885	165.26	532.16	117.70	106.74	106.93	727.70	1110.70	115.97	575.50	221.70
1986	127.30	232.03	75.78	116.44	113.57	345.50	1014.10	122.23	584.77	206.20
1987	93.12	466.56	80.31	126.32	122.10	301.20	2112.70	125.04	589.95	201.10
1988	137.98	454.96	55.98	135.46	133.43	539.00	1344.20	125.54	589.95	189.10

(a) Drilled in exploration and development; Australian Petroleum Exploration Association Limited, *Exploration and Development Statistics* (various issues), Sydney. (b) Australian Bureau of Statistics, *NIF-10 tape*, Cat. no. 1313.0 series for PGCO, Canberra. (c) Derived from value and constant price series NGDP and NGDPZ; Australian Bureau of Statistics, *Timeseries tape*, Cat. no. 1311.0, Canberra. (d) Spent on exploration, development and production; source as (a). (e) Cumulative commercial and non-commercial reserves by year of discovery; mimeograph notes from the Bureau of Mineral Resources, Geology and Geophysics. (f) Source as (a).

TABLE B.3

Econometric Results

Demand for petroleum products

(B.9) $\ln QD = 1.1458 - 0.0311 \ln (OILP/CPI) + 0.1907 \ln (GDP/POP)$
(5.72) (–3.50) (2.22)

$+ 0.7692 \ln QD_{-1}$
(15.19)

$R^2 = 0.984$ $\bar{R}^2 = 0.982$; D-H = –0.653

Serial correlation: $\chi^2(1) = 0.562$ Functional form: $\chi^2(1) = 0.817$
Normality: $\chi^2(2) = 0.858$ Heteroscedasticity $\chi^2(1) = 0.006$
Predictive failure: $\chi^2(4) = 1.859$

Drilling effort onshore

(B.10) $\ln ONM = 3.2042 + 0.4401 \ln (OILP/CPI)$
(8.61) (4.03)

$-0.6271 \ln (INVON/(ONM.GDPDE))$
(–3.57)

$-0.7920 \ln (PROD/(ONM + OFM))$
(–6.59)

$R^2 = 0.964$; $\bar{R}^2 = 0.955$; DW =1.207

Serial correlation: $\chi^2(1) = 2.101$ Functional form: $\chi^2(1) = 1.329$
Normality: $\chi^2(2) = 0.335$ Heteroscedasticity: $\chi^2(1) = 0.299$
Predictive failure: $\chi^2(4) = 7.285$

Drilling effort offshore (D = 1 if 1972 to 1980)

(B.11) $\ln OFM = 4.6390 + 0.5471 \ln (OILP/CPI)$
(16.05) (6.48)

$-0.2009\, D \ln (OILP/CPI) - 1.4379 \ln (INVOF/(OFM.GDPDE)$
(–2.79) (–12.24)

$+ 0.8625\, D \ln (INVOF/(OFM.GDPDE))$
(5.78)

$R^2 = 0.961$; $\bar{R}^2 = 0.948$; DW = 2.172

Serial correlation: $\chi^2(1) = 0.493$ Functional form: $\chi^2(1) = 0.009$
Normality: $\chi^2(2) = 1.577$ Heteroscedasticity: $\chi^2(1) = 0.102$

TABLE B.3 (continued)

Cumulative onshore reserves (CU denotes cumulative series)

(B.12) $$\underset{(27.35)}{\text{CUONRES} = 127.0540}/(1 + \underset{(7.05)}{10.3369} \exp(\underset{(10.38)}{-0.0015}\ \text{CUONM}))$$

$R^2 = 0.995$; $\bar{R}^2 = 0.994$; $DW = 2.404$

Cumulative offshore reserves (CU denotes cumulative series)

(B.13) $$\underset{(20.08)}{\text{CUOFRES} = 683.3520}/(1 + \underset{(9.18)}{9.0378} \exp(\underset{(11.28)}{-0.0023}\ \text{CUOFM}))$$

$R^2 = 0.996$; $\bar{R}^2 = 0.996$; $DW = 1.479$

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