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Sensitivity Analysis of ORION

D. B. Reister
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Engineering Physics and Mathematics Division

SENSITIVITY ANALYSIS OF ORION

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GLOSSARY

ANETPV	Net Present Value Subroutine
API	Crude Oil Gravity
AVDEP	Total Footage per Well
BFAC	Lease Bonus Rate
CODEL	Development Well Cost - Alaska
CODRY	Development Dry Hole Rate
COEXP	Exploratory Drilling Cost
COPRO	Producing Well Cost
DDHR	Development Dry Hole Rate
DELR	Development Wells
DEPLIF	Depreciation Life
DFOOT	Production Drilling Rate
DHCOS	Dry Hole Cost
DHOST	Delineation Hostility Factor
DISCRT	Discount Rate
DRILCO	Drilling Cost for a Well
DRILDP	Total Drilled Depth
DRILL	Total Footage(Successful & Dry Hole)
DS	Successful Development Wells
EFOOT	Exploratory Drilling Rate
EHOST	Exploratory Hostility Factor
EQICO	Production Equipment Cost
EQUICO	Equipment Cost for a Well
ESUCR	Exploratory Success Rate
FR(1)	Successful Finding Rate
FTAX	Federal Income Tax Rate
GARATE	General & Administrative Rate
GNGRAT	Geological & Geophysical Rate
GRESS	Automated Sensitivity Analysis Code
IFLD	Field Production Tables
INCTC	Income Tax Credit Rate
INFOP	Waterflood Operating Cost for a Well
INJEQ	Injection Equipment Cost for a Well
INTANG	Expensed (Intangible) Investment
IPTIM	Time to Build a Platform
IWUL	Well Production Tables
KTFAC	Kalter-Tyner Factor
LOMULT	Small Field Production Profile
MPROD	Natural Gas Production
OPCO(1)	Fuel & Power Operating Cost
OPCO(2)	Labor & Materials Operating Cost
OPCO(3)	Water Cost
OPCOS	Operating Cost for a Well
OPOVHD	Operations Overhead Rate
OPRAT	Operating Cost Ratios
ORION	ORNL Version of REPCO
PGOR	Production Gas-Oil Ratio
PIPCO	Pipeline Cost
PLATCO	Platform Cost
PMULT	Large Field Production Profile
POPN	Platform Operating Cost

GLOSSARY (Cont'd)

PRCHG	Inflation Factor in ANETPV
RECOIL	Field Size
REGTRA	Transportation Cost
REPCO	Replacement Cost of Oil Code
RESV	New Field & New Pool Reserve Discoveries
ROYL	Royalty Rate
SALEYR	Year When Sales Begin
SEV	Severance Tax Rate
SGOR	Total Gas-Oil Ratio
STAX	State Income Tax Rate
TANG	Capitalized (Tangible) Investment
TD	Total Development Wells
WATCO	Cost per Barrel of Water
WATRDP	Water Depth
WELLS	Successful Exploratory Oil Wells
WFDCO	Waterflood Cost
WOPN	Platform Operating Cost per Well
WPR	Windfall Profits Tax Rate
WULT	Well Ultimate Recovery
XOPCO(1)	Fuel & Power Operating Cost
XOPCO(2)	Labor & Materials Operating Cost
XOPCO(3)	Water Cost
YPROD	Crude Oil Production
169000	Secondary Recovery Fixed Cost

ABSTRACT

The replacement cost of oil is the constant selling price that will recover the full expenses of exploration, development, and production of domestic crude oil with a reasonable return on capital. The computer code ORION calculates the replacement cost of oil for 20 regions of the United States: 6 onshore regions and 14 offshore regions. The replacement cost depends on parameters like the finding rate for oil, capital costs, operating costs, tax rates, and the discount rate.

This report presents the results of a sensitivity analysis of ORION. In the analysis, sensitivity coefficients were calculated for all of the parameters in ORION; the coefficients are defined to be the ratio of the percentage change in the replacement cost to the percentage change of a parameter. The sensitivity analysis of ORION was performed using an automated procedure based on the GRESS precompiler.

For both the offshore and onshore regions, the parameter with the largest sensitivity coefficient was the discount rate. The sensitivity coefficient for the discount rate is approximately equal to the lead-time. Since the lead-times are 3 years for the onshore regions and 5 to 15 years for the offshore regions, the discount rate coefficients can be significantly larger than 1.0.

For the onshore regions, parameters related to oil production (like the reserve discoveries and the number of exploratory wells) had large sensitivity coefficients. For the offshore regions, a weather parameter had large sensitivity coefficients.

1. INTRODUCTION

The objective of the Department of Energy's Fossil Energy (DOE-FE) program is to manage a program of long-term, high-risk R&D to develop advanced energy technologies that produce or consume fossil energy. The management of the program continually faces the question: when will an advanced technology be competitive with any alternative technologies? The standard method for comparing a set of alternative technologies is to perform a discounted cash flow analysis. There are many types of discounted cash analysis; one of the standard methods is to calculate a life-cycle cost for each alternative technology. The life-cycle cost is the constant or levelized cost that will recover all of the costs necessary to produce the product over the life-cycle of the project. The technology with the lowest life-cycle cost will be the market choice. DOE-FE supports research to produce liquid and gaseous fuels. The conventional technology to produce these fuels is to drill wells to extract liquid or gaseous fuels. Since the advanced technologies must compete with the conventional technology, the life-cycle cost of conventional oil and natural gas is of interest to the management of the Fossil Energy program.

Conventional oil and gas are finite resources. As the resources are consumed, the life-cycle cost of the next barrel, the replacement cost, will increase. As the replacement cost increases and R&D lowers the cost of advanced energy technologies, eventually the advanced technologies will penetrate the market.

The Fossil Energy program has sponsored research by the Oak Ridge National Laboratory (ORNL) and its subcontractor Lewin and Associates, Inc. (L&A) to develop a set of computer models to forecast the replacement cost of domestic crude oil and natural gas. The I&A versions of the models are called REPCO while the ORNL versions are called ORION. Both REPCO and ORION calculate the same values for the replacement costs for 16 of the 20 regions. The replacement cost methodology used in the models is described in detail in reference one. The differences between REPCO and ORION will be discussed following a brief discussion of the replacement cost methodology.

The replacement cost of domestic crude oil is the constant or levelized selling price that will recover the full expenses of exploration, development, and production with a reasonable return on capital. In ORION, the replacement cost contains the full cost of adding new reserves, including:

Initial investment costs for geological work, lease costs, dry holes, and the discovery well;

The subsequent investment costs for developing the oil field;

Normal operating costs, plus any special costs for conducting secondary and enhanced oil recovery;

Price adjustments for crude oil gravity and transportation;

Royalties, severance taxes, Windfall Profits Taxes, and federal and state income taxes; and

Return on capital, based on a discount rate that reflects the long term return on invested capital within the petroleum industry.

The heart of ORION is the calculation of net present value in the subroutine ANETPV. Consider a project with a lifetime of M years. For the first few years, the operators of the project will be drilling wells and making other investments; and the after-tax cash flow will be negative. When the project begins to produce oil and gas, the after-tax cash flow will depend on the selling price for the gas and oil; the higher the selling price, the higher the after-tax cash flow. A project recovers the full expenses of exploration, development, and production with a reasonable return on capital when the discounted sum of the after-tax cash flow over the lifetime of the project is zero. The replacement cost of domestic crude oil is the price of oil (constant over the lifetime of the project) that will yield a zero net present value; that is, a zero value for the discounted sum of the after-tax cash flow over the lifetime of the project.

Given time histories of capital investment, operating costs, and production rates; and parameters like the discount rate and tax rates, the subroutine ANETPV will calculate the net present value for any given price of oil. One of the major differences between REPCO and ORION is that REPCO uses the method of bisection to calculate the replacement cost, while ORION uses Newton's method. The method of bisection consists of choosing the next guess at the replacement cost as the average of the two previous guesses that were the best upper and lower bounds. Newton's method consists of connecting the two previous best guesses with a line and using the line to estimate the price that will yield a zero net present value. Although the two methods converge to the same result, Newton's method is generally much faster than the method of bisection.

For the four offshore Atlantic Coast regions, REPCO and ORION calculate different values for the replacement cost. In both models, the time required to build a platform (IPTIM) is one year for each 300 feet of water depth. However, when the water depth is exactly 300 feet (or 1500 feet), REPCO calculates a building time of 2 years (or 6 years); while ORION calculates a building time of 1 year (or 5 years).

Since the water depth is 300 feet for the two Atlantic Coast shelf regions and 1500 feet for the two Atlantic Coast slope regions, ORION calculates a lower value for the replacement cost for the four Atlantic Coast regions than REPCO.

This report presents the results of a sensitivity analysis of the ORION model for the replacement cost of domestic crude oil. In the model, the replacement cost depends on parameters like historical data on the finding rate, capital costs, operating costs, tax rates, and the discount rate. In the analysis, sensitivity coefficients were calculated; the coefficients are defined to be the ratio of the percentage change in the replacement cost to the percentage change of a parameter.

Conventional sensitivity analysis normally is performed using a perturbation procedure. In a perturbation analysis, a parameter is varied by a small amount (for example, one percent) and the sensitivity coefficient is estimated by comparing the perturbed replacement cost to the base case cost. The perturbation approach becomes impractical for large models with many parameters.

The sensitivity analysis of the ORION model was performed using an automated procedure based on the GRESS precompiler (GRESS is an acronym for GRadient-Enhanced Software System). In the automated procedure, GRESS is used to process the FORTRAN code for the model. For every equation in the model, GRESS automatically enhances the code with new FORTRAN code to analytically calculate the derivative of the replacement cost with respect to each parameter selected for analysis. When the gradient enhanced version of the model is run, both the replacement costs and the sensitivity coefficients are calculated by a single run. The GRESS procedure is described in more detail in references two and three.

ORION calculates a supply curve; a schedule of replacement cost versus increments of undiscovered petroleum. Sensitivity analysis could be performed for both the replacement cost and the increments of undiscovered oil. Since the magnitude of the increments of undiscovered petroleum is directly related to the input data, no additional insights about the model structure could be gained by performing a sensitivity analysis for these variables. Since the path from input data to replacement cost is long and tortuous, we focused our study on the sensitivity analysis of the replacement cost.

ORION uses two different methods to calculate replacement costs: one method for onshore oil and another method for offshore oil. The sensitivity analysis of the onshore model is presented in section two while the analysis of the offshore model is in section three. To validate the results of the automated analysis using GRESS, a perturbation analysis was performed for selected parameters. The validation of the GRESS analysis will be discussed in section four.

To improve our understanding of the results of the sensitivity analysis, we will develop an approximate analytical expression for the replacement cost in section five. Using the analytical expression for the replacement cost, we will derive analytical expressions for several of the sensitivity coefficients. The analytical expressions for the sensitivity coefficients will help us understand the magnitudes of the coefficients and the relationships between the coefficients.

The conclusions of the sensitivity analysis are presented in section six. The detailed results of the analysis for the onshore and offshore models are presented in two appendixes. A third appendix presents arguments in favor of decreasing the magnitude of one of the most significant parameters (PRCHG).

2. GRESS RESULTS FOR THE ONSHORE MODEL

To calculate the replacement cost for domestic crude oil, ORION uses two different methods; one for onshore and the other for offshore. This section will discuss the GRESS results for the onshore model. The onshore module calculates the replacement cost for six regions:

1.	West Coast	2.	Rocky Mountains
3.	Midcontinent	4.	West Texas
5.	Gulf Coast	6.	Appalachia.

For each region, the onshore module divides the estimate of undiscovered resource into eight equal increments or intervals and calculates the replacement cost for each interval. For example, the undiscovered oil in the West Coast region is estimated to be 4,256 million barrels. Each interval is allocated one eighth of the total; that is, 532 million barrels. The base case replacement costs are displayed in the following table. For the West Coast region, the replacement cost for the first 532 million barrels is $18.34 per barrel; for the sixth increment of 532 million barrels, the replacement cost is $69.93 per barrel.

As the resources are discovered, the replacement cost for the next resource interval increases. Thus, for each region, the replacement cost increases steadily as the amount of undiscovered resource decreases. For the first region (West Coast), the replacement cost increases from $18 to $70 as the resource is consumed. For the fourth region (West Texas), the replacement cost increases from $54 to $133 as the resource is consumed. The replacement cost is higher for West Texas because the region has been thoroughly explored and more of the resource has been found.

If the replacement cost is greater than $200, ORION stops the calculation and reports a replacement cost of $199.99 (for example, the base case replacement costs for the eighth resource interval are all more than $200 and are not shown in Table 1). When the replacement cost is greater than $200, the reported replacement cost ($199.99) is not sensitive to small changes in parameter values. Thus, we cannot perform a sensitivity analysis when the replacement cost is greater than $200.

We have calculated sensitivity coefficients for 42 parameters; 31 of the parameters are input data; 10 of the parameters are intermediate results; and one of the parameters is related to the structure of the model. All of the input data is represented by the 31 parameters; some of the parameters are single numbers (for example, the discount rate), while other parameters are related to arrays.

An example is the parameter for the array PMULT, the large field production profile. PMULT is an array of 20 numbers that are the fraction of production that occurs in each year. We could call each of the 20 numbers a parameter and calculate 20 separate sensitivity

Table 1. Replacement Cost of Domestic Crude Oil
by Region and Resource Interval

Units - $1983 per Barrel

Resource Interval	Region 1	2	3	4	5	6
1	18.34	21.73	21.80	54.41	16.58	18.83
2	20.85	24.49	24.30	73.11	18.74	21.07
3	24.68	27.75	27.30	77.32	21.16	23.96
4	31.73	35.35	32.98	132.70	25.16	26.15
5	46.32	54.92	38.84	199.99	31.51	36.17
6	69.93	89.15	62.00	199.99	40.12	58.90
7	199.99	199.99	141.93	199.99	72.14	119.58

coefficients. Since each of the elements of PMULT has a similar role in the calculation, we introduce a single parameter (equal to unity) that multiplies each element in PMULT. By introducing this parameter, we can analyze the sensitivity of the replacement costs to a uniform change in all of the elements of the array.

For a large field, the annual oil production is the product of the total production over the 20 year life of the well and PMULT. Increasing each element of PMULT by 1% is equivalent to increasing the total production from a well by 1%. Thus, the sensitivity coefficient for the PMULT parameter is a measure of the change in replacement cost due to a change in oil production.

The intermediate parameters were included to allow comparisons between the onshore and offshore models; most of the intermediate parameters are inputs to the subroutine ANETPV, which is used by both models. The structural parameter (PRCHG) causes the model to have higher sensitivities when the replacement cost is greater than $30.

For each of the 42 parameters, sensitivity coefficients were calculated using GRESS; the coefficients are defined to be the ratio of the percentage change in the replacement cost to the percentage change in the parameter. For the onshore model, there are 42 replacement costs displayed in Table 1; 5 of the replacement costs are greater than $200. Thus, sensitivity coefficients can be calculated for 37 replacement costs and 42 parameters; for a total of 1554 coefficients.

The detailed results are displayed in Appendix A. The first table in Appendix A is a summary of the results; for each of the 42 parameters, the summary table displays the maximum value, the minimum value, and the mean value of the 37 sensitivity coefficients. Since the sensitivity coefficients are higher when the replacement cost is greater than $30, the summary table displays separate maximum, minimum, and mean values for the low replacement costs (the 17 replacement costs that are less than $30) and for the high replacement costs (the 20 costs that are greater than $30).

Tables A-2 to A-34 in Appendix A present detailed sensitivity coefficients for 33 of the 42 parameters. The criteria for choosing the 33 parameters was that the mean value for the sensitivity coefficients for replacement costs that are greater than $30 should be larger in magnitude than 0.10.

ORION is a bimodal model; the two modes are: less than $30 and more than $30. The bimodal behavior begins at a replacement cost of $30 when the inflation factor PRCHG is activated in the subroutine ANETPV. The bimodal behavior of ORION is clear in Table A-2 of Appendix A. For the 17 replacement costs that are less than $30, the sensitivity coefficient for the discount rate ranges from 2.90 to 4.35. For the 20 replacement costs that are greater than $30, the coefficient ranges from 6.03 to 15.59. Furthermore, the values in Table 2 of Appendix A generally increase down the column. As the replacement cost increases, the sensitivity coefficient increases.

In Tables A-3 and A-4 of Appendix A, the sensitivity coefficients are larger when the replacement cost is more than $30, but the magnitudes of the values do not increase down the column. The Tables in Appendix A illustrate that ORION is a bimodal model but they do not explain why ORION is bimodal. In Appendix C, we discuss the inflation factor PRCHG and explain how PRCHG causes ORION to be bimodal.

In this section, we will confine our attention to 20 of the 31 input parameters. The criterion for choosing the 20 parameters was that they had the largest mean values for the sensitivity coefficients when the replacement costs were less than $30. The 20 parameters and the mean values for sensitivity coefficients for high and low replacement costs are displayed in Table 2. The bimodal behavior of ORION is clear in Table 2; in most cases, the mean values for the sensitivity coefficients increase by at least a factor of two when the replacement cost is high.

Table 2. The Onshore Model Input Parameters with the Largest Sensitivity Coefficients

	Cost < $30	Cost > $30	
k	Mean	Mean	Parameter
1	3.82	9.51	DISCRT - Discount Rate
2	1.16	2.84	WELLS - Exploratory Oil Wells
3	-1.16	-2.84	RESV - New Reserve Discoveries
4	-0.98	-2.46	LOMULT - Small Field Profile
5	-0.96	-1.87	PMULT - Large Field Profile
6	0.36	0.76	DRILCO - Drilling Cost
7	0.31	1.02	IWUL - Well Production Tables
8	0.28	0.38	TD - Total Development Wells
9	-0.28	-0.38	DS - Successful Develop Wells
10	0.26	0.51	OPRAT - Operating Cost Ratios
11	0.17	0.37	DEPLIF - Depreciation Life
12	0.14	0.52	DHCOS - Dry Hole Cost
13	0.14	0.27	OPCOS - Operating Cost
14	0.14	0.33	ROYL - Royalty Rate
15	-0.13	-0.31	API - Crude Oil Gravity
16	0.12	0.26	EQUICO - Equipment Cost
17	0.12	0.24	INFOP - Waterflood Cost
18	0.10	0.19	FTAX - Federal Income Tax Rate
19	-0.09	-0.40	IFLD - Field Production Tables
20	-0.08	-0.17	INCTC - Income Tax Credit Rate

The parameter with the largest sensitivity is the discount rate (DISCRT). The mean values for the sensitivity coefficients for the discount rate are 3.82 when the replacement cost is less than $30 and 9.51 when the replacement cost is greater than $30. In Table 6 of the next section, we will show that when the replacement cost is less than $30 the sensitivity coefficient for the discount rate is approximately equal to the lead-time between the start of drilling and the start of production. For the onshore regions, the lead time is three years and the sensitivity coefficients range from 2.90 to 4.35 with an average of 3.82. Thus, the sensitivity coefficients are approximately equal to 3.0, the lead time, when the replacement cost is less than $30.

In addition to having a large sensitivity coefficient, the discount rate is a controversial parameter. Economists can have heated arguments about whether the discount rate should be 3% or 10%, which is the value used in ORION. The discount rate is used to compare a future dollar to a current dollar. For the public sector, the discount rate could be the real interest rate on government bonds; the interest rate minus the inflation rate. For the period from 1961 to 1984, the average real interest rate was 1.4%. In the last few years, the real interest rate has been higher; the average rate for the period from 1980 to 1984 was 4.4%. For the private sector, the average value for the prime rate was 3.3% from 1961 to 1984 and 7.9% for the period from 1980 to 1984. The appropriate discount rate for ORION should be the real interest rate for the oil and gas industry, which has been somewhat higher than the prime rate.

The next four parameters in Table 2 (WELLS, RESV, LOMULT, and PMULT) are related to the crude oil production from an average well.

To aid in the understanding of the sensitivity coefficients for the production parameters, we will summarize the calculation in ORION. The units of the replacement cost are dollars per barrel. An increase in production will cause a decrease in replacement cost. If a 1% increase in production increases revenue by 1% without any increase in expenses, the replacement cost would decrease by 1% and the sensitivity coefficient would be -1.0. Thus, the magnitude of the sensitivity coefficients for the production parameters should be approximately equal to 1.0, when the replacement cost is less than $30. As expected, the mean values of the sensitivity coefficients for the production parameters (WELLS, RESV, LOMULT, and PMULT) are in the neighborhood of 1.0, when the replacement cost is less than $30 (see Table 2).

In addition to the four production parameters in Table 2, sensitivity coefficients were calculated for five other production related parameters (YPROD, DELR, FR(1), AVDEP, and DRILL). Since the production parameters have large sensitivity coefficients, we will discuss the role of each of the nine parameters in the calculation of replacement cost. In ORION, the production from a field (YPROD) is a convolution of production from a well (PROD) and the number of development wells (DELR); that is, total production from a field is the sum of production from individual wells. The production schedule for a well is the product of the total oil ultimately recovered from a well (WULT) and the production profile. Two production profiles are used: PMULT and LOMULT. PMULT is the production profile for large fields while LOMULT is the profile for small fields.

The total oil ultimately recovered from a well (WULT) is the product of the finding rate (FR(1)) and the average depth of a well (AVDEP). The finding rate (measured in barrels per foot) is the quotient of historical data on the discovery rate of reserves (RESV measured in barrels) and historical data on total feet of drilling (DRILL measured in feet). The average depth is the quotient of the total feet of drilling (DRILL) and historical data on the total number of wells that were drilled (WELLS measured in numbers of wells). Since the finding rate is the quotient of RESV and DRILL and the average depth is the quotient of DRILL and WELLS, the total oil ultimately recovered from a well does not depend on DRILL, that is

$$\text{WULT} = \frac{\text{RESV}}{\text{DRILL}} \; \frac{\text{DRILL}}{\text{WELLS}} = \frac{\text{RESV}}{\text{WELLS}}$$

Thus, an increase in RESV will decrease the replacement cost; an increase in WELLS will increase the cost; while an increase in DRILL will have no effect.

In Table 2, the average sensitivity coefficients for WELLS and RESV have equal magnitudes and the expected signs. In Table 1 and the detailed tables of Appendix A, we find that the sensitivity coefficient for DRILL is zero and that the coefficients for AVDEP have exactly the same magnitude as the coefficients for WELLS and RESV and the expected sign.

We expected that the sensitivity coefficients for the other production parameters (LOMULT, PMULT,FR(1), and YPROD) would have about the same magnitudes as WELLS, RESV, and AVDEP. While the magnitudes are not identical, they are all in the neighborhood of 1.0 (when the replacement cost is less than $30) and have the correct signs. The final production parameter (DELR) increases both the production and the cost of production. Since it increases both the numerator (dollars) and the denominator (barrels), DELR has a small sensitivity coefficient.

The finding rate [FR(1)] is the quotient of historical data on the discovery rate of reserves and total feet of drilling and has a large sensitivity coefficient. Differences in the finding rate are a partial explanation of why the replacement cost is much higher in region 4 than in the other regions (see Table 1). For the first increment of undiscovered resource, the finding rate is 8 barrels/foot in region 4; the equivalent finding rates in the other regions range from 15 to 39 barrels/foot.

The remaining 15 parameters in Table 2 are cost parameters or elements in tables. The sensitivity coefficient for a cost parameter is approximately equal to the share of the total expenses associated with the parameter. Thus, the sensitivity coefficients for cost parameters are generally positive and much less than 1.0 (when the replacement cost is less than $30). The cost parameter with the highest sensitivity coefficient is the drilling cost (DRILCO). In general, the meaning and signs of the cost parameters are clear. For example, an increase in the income tax rate increases the replacement cost while an increase in the income tax credit rate decreases the replacement cost. The parameter API is related to a gravity penalty for heavy oils and is discussed on page 124 of Ref. 1.

The table IWUL is the expected ultimate recovery from a well by region and field size. The table IWUL for the West Coast region is Table A-5 in Ref. 1. To perform the sensitivity analysis for IWUL, we multiplied each element in the table by a parameter (equal to unity) and computed sensitivity coefficients with respect to the parameter. IWUL is used to put a upper bound on WULT. Since IWUL does not influence the replacement cost if WULT is less than IWUL, IWUL has a lower sensitivity coefficient than the other production parameters. The fact that IWUL sometimes enters the calculation may be the explanation of why some production parameters (YPROD, LOMULT, PMULT, and FR(1)) have a lower sensitivity coefficient than the other production parameters (WELLS, RESV, and AVDEP).

The tables DS and TD are the successful development wells and the total development wells. The ratio of DS and TD is the fraction of all development wells that are successful. Thus, the fraction of all development wells that are dry (DDHR) is unity minus the ratio; that is

$$DDHR = 1 - (DS/TD)$$

DDHR has an impact on the cost of production. Thus, the sensitivity coefficients for DS and TD are similar in magnitude to the other cost parameters and have equal magnitudes and opposite signs.

In conclusion, the sensitivity coefficients for the cost parameters tend to be less than for the production parameters. The parameter with the largest sensitivity coefficient is the discount rate. The model is bimodal with the mode separation occurring at a replacement cost of $30.

3. GRESS RESULTS FOR THE OFFSHORE MODEL

This section will discuss the GRESS results for the offshore section of ORION. Detailed results are presented in Appendix B. The offshore module calculates the replacement cost for 14 regions:

1. Alaska Shelf - Low Risk
2. Alaska Shelf - High Risk
3. Alaska Slope - Low Risk
4. Alaska Slope - High Risk
5. West Coast South - Shelf
6. West Coast North - Shelf
7. West Coast South - Slope
8. West Coast North - Slope
9. Gulf of Mexico - Shelf
10. Gulf of Mexico - Slope
11. Atlantic Coast North - Shelf
12. Atlantic Coast North - Slope
13. Atlantic Coast South - Shelf
14. Atlantic Coast South - Slope

In the onshore module, the undiscovered resource in each region is divided into equal increments and a replacement cost is calculated for each increment. For the offshore module, the replacement cost is calculated for each of the 20 field classes defined by the United States Geological Survey (USGS) [see Table 3]. The base case replacement costs are displayed in Table 4 (the replacement costs are greater than $200 for the first nine field classes and are not included in Table 4).

Field class 20 has the largest amount of crude oil in a field (see Table 3). The upper and lower boundaries decrease by a factor of two for each of the 20 field classes; that is, the upper boundary for field class 20 is 3109 million barrels of oil equivalent, the upper boundary for class 19 is 1554, and the upper boundary for class 18 is 777. As the field class (and available oil) decreases, the replacement cost increases. Thus, for each region, the

Table 3. USGS Field Size Classes

Units - Million Barrels of Oil Equivalent

Field Class	Class Limits Lower	Upper
1	0.0	0.006
2	0.006	0.012
3	0.012	0.024
4	0.024	0.047
5	0.047	0.095
6	0.095	0.19
7	0.19	0.38
8	0.38	0.76
9	0.76	1.52
10	1.52	3.04
11	3.04	6.07
12	6.07	12.14
13	12.14	24.3
14	24.3	48.6
15	48.6	97.2
16	97.2	194.3
17	194.3	388.6
18	388.6	777.2
19	777.2	1554.4
20	1554.4	3109.0

Source: Ref. 4.

replacement cost increases steadily down the columns of Table 4. If the replacement cost is greater than $200, ORION stops the calculation and reports a replacement cost of $199.99. Since we cannot perform a sensitivity analysis when the replacement cost does not depend on the parameter values, we will restrict our sensitivity analysis to replacement costs that are less than $200.

The replacement cost is much higher in Alaska than for the lower 48 states. For Alaska, the cost starts above $35 per barrel and rapidly escalates to $199.99. For the lower 48, the replacement cost

Table 4. Replacement Cost of Crude Oil by Region and Field Class

Units - $1983 per Barrel

Field Class	Region 1	2	3	4	5	6	7
20	38.08	43.03	64.78	89.28	9.80	11.00	15.56
19	41.86	48.28	78.62	117.52	10.51	11.97	17.08
18	51.28	62.01	123.67	199.99	11.48	13.30	19.24
17	70.27	92.62	199.99	199.99	12.82	15.14	23.36
16	84.72	135.78	199.99	199.99	15.69	19.10	25.21
15	168.74	199.99	199.99	199.99	17.47	21.74	29.54
14	199.99	199.99	199.99	199.99	22.01	28.26	56.28
13	199.99	199.99	199.99	199.99	23.64	31.40	145.09
12	199.99	199.99	199.99	199.99	32.06	55.33	199.99
11	199.99	199.99	199.99	199.99	53.30	105.65	199.99
10	199.99	199.99	199.99	199.99	146.05	199.99	199.99

Field Class	Region 8	9	10	11	12	13	14
20	18.82	11.57	19.07	10.54	21.57	7.89	19.45
19	21.38	12.40	21.16	11.38	21.00	7.50	20.93
18	25.03	12.97	24.22	12.69	25.22	8.56	25.37
17	33.74	15.47	31.41	14.28	35.52	8.63	30.22
16	37.28	18.52	39.40	19.75	54.45	10.20	41.22
15	54.98	23.18	49.25	22.91	199.99	10.76	81.81
14	166.12	28.47	91.11	25.86	199.99	12.29	199.99
13	199.99	39.21	199.99	29.93	199.99	15.08	199.99
12	199.99	51.30	199.99	46.58	199.99	21.98	199.99
11	199.99	108.81	199.99	102.93	199.99	31.74	199.99
10	199.99	199.99	199.99	199.99	199.99	81.69	199.99

for the largest field size ranges from $8 to $22 and the cost escalates less rapidly to $199.99. For all regions, the replacement cost is higher in the slope region than in the shelf region; the reason is that the water depth is greater in the slope region.

We have performed a sensitivity analysis for 47 parameters; 28 of the parameters are input data; 7 of the parameters are intermediate results; 11 of the parameters are related to costs; and one of the parameters is related to the structure of the model. All of the input data is represented by the 28 parameters; as before, some of the parameters are single numbers, while other parameters are related to arrays.

The intermediate parameters were included to allow comparisons between the onshore and offshore models; most of the intermediate parameters are inputs to the subroutine ANETPV, which is used by both models. For the onshore model, the cost parameters were input data; for the offshore model, the cost parameters are calculated in the subroutine DEVSKD and can depend on the input data. As before, the structural parameter (PRCHG) causes the model to have higher sensitivities when the replacement cost is greater than $30.

For each of the 47 parameters, sensitivity coefficients were calculated using GRESS; the coefficients are the ratio of the percentage change in the replacement cost to the percentage change in the parameter. For the offshore model with 14 regions and 11 field classes intervals, there are 154 replacement costs displayed in Table 4. For the base case costs displayed in Table 4, 53 of the replacement costs are greater than $200. Thus, sensitivity coefficients were calculated for 101 replacement costs with respect to 47 parameters; for a total of 4747 coefficients.

The sensitivity coefficients for many of the parameters are small or zero. Detailed results are displayed in Appendix B for 19 of the 47 parameters. The criterion for choosing the 19 parameters was that the mean values for their sensitivity coefficients was greater than

0.10, when the replacement costs that were less than $30. The first table in Appendix B is a summary of the results; for each of the 19 parameters, the summary table displays the maximum value, the minimum value, and the mean value of the 101 sensitivity coefficients. Since the model has higher sensitivity coefficients when the replacement cost is greater than $30, the summary table calculates separate maximum, minimum, and mean values for the low replacement costs (the 57 replacement costs that are less than $30) and for the high replacement costs (the 44 costs that are greater than $30).

In this section, we will confine our attention to 14 of the 19 parameters displayed in Appendix B. The 14 parameters are input parameters or cost parameters. The 14 parameters and the mean values of the sensitivity coefficients for high and low replacement costs are displayed in Table 5.

Table 5. The Offshore Model Parameters with the Largest Sensitivity Coefficients

k	Cost < $30 Mean	Cost > $30 Mean	Parameter
1	9.35	13.38	DISCRT - Discount Rate
2	0.53	1.58	KTFAC - Kalter-Tyner Factor
3	0.38	0.39	FTAX - Federal Income Tax Rate
4	0.22	0.19	BFAC - Lease Bonus Rate
5	-0.22	-0.75	WULT - Well Ultimate Recovery
6	-0.21	-0.66	RECOIL - Field Size
7	-0.21	-0.69	PMULT - Oil Production Profile
8	0.20	0.36	ROYL - Royalty Rate
9	0.17	0.87	WATRDP - Water Depth
10	0.16	0.45	DRILDP - Total Drilled Depth
11	-0.15	-0.38	API - Crude Oil Gravity
12	0.15	0.36	COPRO - Producing Well Cost
13	0.13	0.52	PLATCO - Platform Cost
14	0.12	0.37	DEPLIF - Depreciation Life

Comparing the significant parameters for the onshore model (see Table 2) with the offshore parameters, we note that some parameters are significant for both models (DISCRT, FTAX, and PMULT), while other parameters are unique to the offshore model (KTFAC and WATRDP). The total oil ultimately recovered from a well (WULT) is an important parameter in both models; in the onshore model, WULT was determined by RESV, DRILL, and WELLS; for the offshore model, WULT is an input.

For both the onshore and offshore models, ORION is bimodal. In most cases, the mean values of the sensitivity coefficients increase by at least a factor of two when the replacement cost is greater than $30.

When the replacement costs were less than $30 for the onshore model (see Table 2), the mean value for the discount rate sensitivity coefficients was about 4.0, the mean values for the production parameter coefficients were about 1.0, and the mean values for the cost parameter coefficients were less than 0.4. In Table 5, the corresponding mean value for the discount rate coefficients is much larger and the corresponding mean values for the production parameter coefficients are much smaller than in Table 2.

For both the onshore and offshore calculations, the parameter with the largest sensitivity coefficients is the discount rate. The sensitivity coefficients for the discount rate are significantly larger for the offshore model than for the onshore model. When the replacement cost is less than $30, the sensitivity coefficients range from 2.9 to 4.4 for the onshore model and from 5.8 to 16.6 for the offshore model; the mean values are 3.8 for onshore and 9.4 for offshore. Thus, the sensitivity coefficients for the offshore model have twice the magnitude of the coefficients for the onshore model and have a greater variance.

The reason for the large sensitivity coefficients for the discount rate is that the offshore model has long lead-times, where the lead-time is the investment period before the start of crude oil production. For the onshore model, the lead-time is always three years. For the offshore model, the lead-time is much longer; the values range from 5 years to 15 years. The offshore lead-times are longer because all of the construction (platform, wells, and pipeline) must be completed before production can start. With a 10% discount rate, one dollar today is equivalent to $1.61 in five years and to $4.18 in 15 years. Thus, longer lead-times can have a major impact on the replacement cost.

Sensitivity coefficients for the discount rate are compared to lead-times for selected regions of the offshore model in Table 6. The correlations between coefficients and lead-times are striking; the smallest value in the table (6.37) has the shortest lead-time while the largest value (16.59) has the longest lead-time. For regions 7 and 13, as the lead-times increase and decrease, the coefficients increase and decrease.

The Kalter-Tyner factor (KTFAC) is an index that depends on water depth and climatic conditions. In Table 36 of Ref. 1, the values of KTFAC range from 0.8 for mild weather and shallow water to 4.3 for deep water and severe weather conditions. In the model, the values of KTFAC range from 1.0 to 2.0. In the model, the Kalter-Tyner factor multiplies all of the capital and operating costs. Thus, we would expect the sensitivity coefficient for KTFAC to be in the neighborhood of 1.0. In Table B-1 of Appendix B, the sensitivity coefficients for KTFAC range from 0.86 to 0.20 with a mean value of 0.53, when the replacement costs are less than $30. When the sensitivity coefficient

Table 6. Discount Rate Sensitivity Coefficients Compared to Lead-time for the Offshore Model

Region	Field Class	Sensitivity Coefficient	Lead Time
5	20	8.17	6
	19	8.01	6
	16	7.41	6
	13	6.37	6
7	20	11.97	10
	18	11.35	10
	17	9.89	9
	16	10.76	10
	15	9.37	9
12	20	16.59	15
	19	14.13	13
	18	12.58	12
13	20	10.34	7
	19	9.22	6
	18	10.10	7
	17	8.88	6
14	20	16.20	14
	19	14.65	13
	18	12.96	12

is 0.20, 20% of the replacement cost depends on the capital and operating costs and 80% depends on something else. In section five, we will derive an analytical expression for the sensitivity coefficients for KTFAC and we shall find that the lease bonus can be responsible for 80% of the replacement cost.

The financial parameters (FTAX, BFAC, and ROYL) have much larger sensitivity coefficients for the offshore model than for the onshore model. In section five, we will derive an analytical expression for the replacement cost and use it to analyze the sensitivity coefficients for the financial parameters.

For the onshore model, the production parameters had sensitivity coefficients with average magnitudes of about 1.0 when the replacement costs were less than $30. For the offshore model, the production parameters (WULT, RECOIL, and PMULT) have coefficients with average magnitudes of about 0.2, when the replacement costs are less than $30. The sensitivity coefficients for the production parameters are much smaller for the offshore model because the costs of production are not inputs but are calculated in the subroutine DEVSKD where the costs of production depend on the production parameters. Since a change in a production parameter for the offshore model has an impact on both the numerator and denominator of the expression for the replacement costs, the production parameters have small sensitivity coefficients.

The depth of the field is an important factor; both the water depth (WATRDP) and the drilled depth (DRILLDP) are significant parameters. The water depth and the drilled depth influence both the capital costs and the operating costs. Of the 11 cost parameters, seven depend on the water depth and three depend on the drilled depth.

Since the water depth and drilled depth do not influence all of the cost parameters, while the Kalter-Tyner factor multiplies all of the capital and operating costs, we expect the sensitivity coefficients for DRILDP and WATRDP to be smaller than the coefficients for KTFAC. When the replacement costs are less than $30, the sensitivity coefficients for WATRDP range from 0.63 to 0.02, the coefficients for DRILDP range from 0.53 to 0.04, and the coefficients for KTFAC range from 0.86 to 0.20. As expected, the sensitivity coefficients for DRILDP and WATRDP are smaller than the coefficients for KTFAC.

The crude oil gravity (API) has similar coefficients for both the onshore and offshore model. Of the 11 cost parameters calculated in DEVSKD, only two (COPRO and PLATCO) have mean values for their sensitivity coefficients that are larger than 0.10.

In conclusion, the parameter with the largest sensitivity coefficient for both the onshore and offshore models is the discount rate. The discount rate coefficients for the offshore model are larger than for the onshore model because the lead-times are longer; 3 years for the onshore model and 5 to 15 years for the offshore model. The Kalter-Tyner factor amplifies all costs and has a large coefficient. In contrast to the onshore model, the financial parameters have larger coefficients than the production parameters. The production parameters have lower coefficients than in the onshore model because they influence the cost parameters.

4. VALIDATION OF THE GRESS RESULTS

The sensitivity coefficients calculated by GRESS can be validated by a perturbation calculation; a selected parameter is increased by one percent and ORION is used to calculate a new set of replacement costs; the sensitivity coefficients are approximated by comparing the perturbed results to the base case. When the onshore GRESS results are compared to a perturbation calculation, there is close agreement between the two sets of results. When the offshore GRESS results are compared to a perturbation calculation, there can be close agreement or significant differences between the two sets of results. Exploration of the reasons for the significant differences yields insights into the design of the offshore model.

The approximate sensitivity coefficients calculated by a one percent perturbation cannot be expected to exactly equal the coefficients calculated by GRESS. If the coefficients calculated by a one percent perturbation were within a few percent of the GRESS results, we said there was close agreement between the two sets of results.

Sensitivity coefficients calculated using GRESS are compared to a perturbation calculation for the parameter WELLS in Table 7. In Table 7, the largest difference is less than three percent and all of the other differences are less than two percent. Thus, there is good agreement between the two sets of results.

When the offshore GRESS results are compared to a perturbation calculation, there is good agreement for five parameters (PRCHG, FTAX, DISCRT, KTFAC, and DRILDP) and occasional significant differences for four parameters (WATRDP, WULT, RECOIL, and DDHR).

Table 7. Validation of the GRESS Results for the Parameter WELLS.

Resource Interval	Region 1 GRESS	Region 1 ORION	Region 3 GRESS	Region 3 ORION	Region 5 GRESS	Region 5 ORION
1	1.33	1.35	0.99	0.99	1.05	1.05
2	1.30	1.31	1.00	1.00	1.16	1.15
3	1.39	1.40	1.06	1.06	1.15	1.15
4	3.15	3.23	1.92	1.94	1.15	1.15
5	2.41	2.43	2.07	2.09	2.21	2.24
6	3.00	3.03	2.50	2.53	1.98	1.99

To illustrate a case of good agreement, sensitivity coefficients calculated using GRESS are compared to a perturbation calculation for the parameter DISCRT in Table 8. To perform the perturbation calculation, the parameter was both increased and decreased by 0.1 percent. There is good agreement between the three sets of results except for field class 12 (by reducing the positive perturbation to 0.002% and by reducing the negative perturbation to 0.005%, good agreement was obtained for field class 12).

To illustrate cases with occasional significant differences, sensitivity coefficients calculated using GRESS are compared to a perturbation calculation for the parameters WATRDP and WULT in Tables 9 and 10. For the parameter WATRDP, there is good agreement between the two sets of results for a 1% decrease in water depth. However, there is no agreement for a 1% increase in water depth. A large decrease in replacement cost as a result of a small increase in water depth is counterintuitive. For the parameter WULT, there is good agreement between the three sets of results in most cases. However, in two cases a small decrease in WULT results in a large decrease in replacement cost.

Table 8. Validation of the GRESS Results for the Offshore Model for the Parameter DISCRT in Region Nine

Units - Percent Change in Replacement Cost in Response to a 1% Change in the Parameter

Field Class	Perturbation Up by 0.1%	GRESS	Perturbation Down by 0.1%
20	9.41	9.42	9.42
19	9.24	9.24	9.25
18	7.95	7.95	7.95
17	7.63	7.63	7.64
16	7.43	7.43	7.44
15	7.14	7.14	7.15
14	6.80	6.80	6.81
13	13.17	13.12	13.08
12	11.43	13.55	14.03
11	16.97	16.88	16.81

Table 9. Validation of the GRESS Results for the Offshore Model for the Parameter WATRDP in Region Nine

Units - Percent Change in Replacement Cost in Response to a 1% Change in the Parameter.

Field Class	Perturbation Up by 1%	GRESS	Perturbation Down by 1%
20	-2.56	0.04	0.04
19	-2.84	0.05	0.05
18	-2.55	0.06	0.06
17	-4.39	0.08	0.08
16	-1.60	0.07	0.07
15	-5.76	0.08	0.08
14	0.34	0.10	0.10
13	-22.55	0.22	0.21
12	-11.61	0.20	0.21

Table 10. Validation of the GRESS Results for the Offshore Model for the Parameter WULT in Region Nine

Units - Percent Change in Replacement Cost in Response to a 1% Change in the Parameter.

Field Class	Perturbation Up by 1%	GRESS	Perturbation Down by 1%
20	-0.76	-0.22	-0.22
19	-0.24	-0.24	-0.25
18	-0.31	-0.31	-9.01
17	-0.35	-0.35	-0.35
16	-0.37	-0.37	-8.37
15	-0.39	-0.40	-0.40
14	-0.42	-0.42	-0.42
13	-0.87	-0.87	-0.87
12	-1.28	-1.24	-1.05

The large values for the sensitivity coefficients in Tables 9 and 10 deserve further investigation. For the parameter WATRDP, a detailed investigation was performed for field classes 17 to 20. As the water depth increases by 1%, from 200 feet to 202 feet, the number of platforms decreases by a factor of two and the number of drilling slots increases by a factor of two. These large changes in the number of platforms and slots has a substantial impact on the capital costs. For the parameter WULT, a detailed investigation was performed for field class 18. As the oil per well decreases by 1%, the number of development wells increases by 1% and causes the development time to increase from six years to seven years. The increase in development time stretches out the investment period and delays the start of production by one year.

In both cases, the large differences between the GRESS results and the perturbation calculations are caused by step-functions in ORION. A step-function has a constant value for a range of parameter values and jumps to a new constant value for the next range of parameter values. In ORION, all of the step-functions are related to integer values in the model. The model requires that the number of platforms or slots or the development time be an integer. As a parameter varies smoothly, the integer will step from one value to the next. The derivative of a step-function is zero everywhere but at the jumps. For GRESS, the derivative of the step-function is zero everywhere. However, the perturbation calculation will detect the jumps and find a different result than GRESS.

5. ANALYTICAL RESULTS

In sections two and three, we observed the magnitudes of the sensitivity coefficients for the onshore and offshore models. In this section, we will develop an approximate analytical expression for the replacement cost and develop analytical expressions for the sensitivity coefficients. Using the analytical expressions, we will be able to develop a deeper understanding of the magnitudes of the sensitivity coefficients and the relationships between the coefficients.

The replacement cost of domestic crude oil is the constant or levelized selling price that will recover the full expenses of exploration, development, and production with a reasonable return on capital. The replacement cost (C) is the constant selling price such that the discounted present value of the revenues from selling oil will be equal to the discounted present value of the capital and operating costs required to produce the oil. For a typical project, investment occurs during the lead-time (LT) and production starts in year LT+1, continues for 20 years, and follows a production profile [X(J)] (the production profile is determined by either the array PMULT or the array LOMULT). The royalty payment is a fixed fraction (r) of all revenues after the transportation cost per barrel (TR) has been deducted. The discounted present value of the revenues after royalty payment from selling oil will be given by:

$$\text{Rev} = \sum_{I=1}^{N} R(I)/D^{I} = (1-r)*(C-TR)*D^{-LT} \sum_{J=1}^{20} X(J)/D^{J}, \qquad (1)$$

where N is the total life time of the project, D is the discount rate, and R(I) is revenue in year I. The revenue is zero during the construction period (R(I) =0 for I=1 to LT). The revenues depend on the replacement cost, the royalty rate, and the production rate;

$$R(LT+J) = (1-r)*(C-TR)*X(J), \text{ for } J= 1 \text{ to } 20 \text{ years.}$$

The revenue calculation in ORION is more complex; with different prices for oil and gas, and a gravity penalty. However, since both the gas price and the gravity penalty are proportional to the replacement cost, our simplifying assumptions will not cause an error when we calculate sensitivity coefficients.

The operating cost has three components: fuel and power cost, labor and materials cost, and water cost. We will combine the three components into a single operating cost per barrel (y). The total operating cost [O(I)] depends on the Kalter-Tyner factor (g) and the production rate; that is,

$$O(LT+J) = y*g*X(J), \text{ for } J = 1 \text{ to } 20.$$

The discounted present value of the operating cost may be written:

$$\text{Oper} = \sum_{I=1}^{N} O(I)/D^{I} = y*g*D^{-LT} \sum_{J=1}^{20} X(J)/D^{J}, \qquad (2)$$

The capital cost has three components: the capitalized (tangible) investment, the expensed (intangible) investment, and the lease bonus.

We shall define the capital investment [K(I)] to be the sum of the tangible and intangible investment. The lease bonus (B) is paid in the second year of the project life. The investment is multiplied by the Kalter-Tyner factor but the lease bonus is not. A dollar of income cannot be used to pay back the capital investment until after the payment of taxes. Thus, the capital investment term must be multiplied by a tax factor [f(t)], where t is the tax rate. To a first approximation, $f(t) = 1/(1-t)$. However, the tax laws allow interest to be deducted and allow accelerated depreciation. Hence, we will assume that $f(t) = (1-a*t)/(1-t)$, where a is a positive constant that is less than 1.0. The discounted present value of the investment and lease bonus is given by:

$$\mathrm{Cap} = f(t)*g \sum_{I=1}^{LT} K(I)/D^{I} + f(t)\ B/D^{2} \quad , \tag{3}$$

The discounted present value of the revenues (Rev) is equal to the sum of the present value of the operating costs (Oper) plus the present value of the capital costs (Cap). Using Eqs. (1), (2), and (3), the replacement cost is given by the following expression:

$$C = TR + [1/(1-r)]*[y*g + f(t)*D^{LT}*(g*k + b)] \quad , \tag{4}$$

where k and b are given by:

$$k = \sum_{I} K(I)*D^{-I} / \sum_{J} X(J)*D^{-J} \quad , \text{ and} \tag{5}$$

$$b = B*D^{-2} / \sum_{J} X(J)*D^{-J} \quad . \tag{6}$$

Although k and b depend on the discount rate, we will assume that they are constants. Our assumption will not cause a significant error except when we calculate the sensitivity coefficient for the discount rate.

Equation (4) is an approximate analytical expression for the replacement cost that can be used to derive expressions for sensitivity coefficients. The replacement cost has four components: transportation cost, operating cost, investment cost, and lease bonus. We can define the share of the replacement cost that is due to each of the four components; that is, we define the transportation share (S_t), the operating share (S_y), the investment share (S_k), and the lease bonus share (S_b) by:

$$S_t = TR/C \quad , \tag{7}$$

$$S_y = y*g \;/\; (1-r)*C \quad , \tag{8}$$

$$S_k = f(t)*D^{LT}*g*k \;/\; (1-r)*C, \text{ and} \tag{9}$$

$$S_b = f(t)*D^{LT}*b \;/\; (1-r)*C \quad . \tag{10}$$

The three shares will be positive and their sum will equal 1.0.

Define ϵ_p to be the sensitivity coefficient of the replacement cost with respect to the parameter p; that is,

$$\epsilon_p = \frac{p}{C}\frac{\partial C}{\partial p} \quad . \tag{11}$$

Using Eq. (4), we can show that the sensitivity coefficients with respect to the parameters TR, y, k, and b are equal to the shares; that is, $\epsilon_{TR} = S_t$, $\epsilon_y = S_y$, $\epsilon_k = S_k$, and $\epsilon_b = S_b$.

For both the onshore and offshore models, we can calculate the sensitivity coefficients with respect to transportation cost, capital investment, lease bonus, and operating cost. If Eq. (4) is correct, the sum of the four sensitivity coefficients should equal 1.0 For the onshore model, the operating cost is the sum of three components: OPCO(1), OPCO(2), and OPCO(3) [for the offshore model, the operating cost array is XOPCO]. The sensitivity coefficient for the operating cost is the sum of the sensitivity coefficients for each of its three components. Similarly, the sensitivity coefficient for the capital cost is equal to the sum of the coefficients for TANG and INTANG. The transportation costs are zero for the onshore model. For the offshore model, the transportation costs are high in Alaska, moderate on the West Coast, and low on the Gulf Coast and the Atlantic Coast. The sensitivity coefficient for the lease bonus rate (BFAC) was calculated for both models. However, the sensitivity coefficient for BFAC is zero in several field classes for the offshore model. (The calculation of the lease bonus has an upper bound of $1.00 per barrel. When BFAC would cause a lease bonus of more than $1.00 per barrel, the lease bonus is determined by the upper bound, and BFAC has a sensitivity coefficient of 0.0.)

The sensitivity coefficients with respect to capital investment, lease bonus, and operating cost for the onshore model are displayed in Table 11 for the 17 values of the replacement cost that are less than $30. In Table 11, the sum of the three shares ranges from 0.97 to 1.00. Thus, Eq. (4) appears to be valid for the offshore model. In Table 11, the capital cost has the largest share, the operating cost has the second largest share, and the lease bonus has the smallest share.

Table 11. Replacement Cost Shares for Capital Investment, Lease Bonus, and Operating Cost for the Onshore Model

Region	Resource	Replacement Cost Shares			
	Interval	Capital[a]	Bonus[b]	Operating[c]	Sum
1	1	0.71	0.04	0.25	1.00
1	2	0.72	0.03	0.22	0.97
1	3	0.75	0.03	0.22	1.00
2	1	0.76	0.03	0.19	0.98
2	2	0.77	0.03	0.19	0.99
2	3	0.79	0.02	0.19	1.00
3	1	0.63	0.04	0.31	0.98
3	2	0.64	0.03	0.31	0.98
3	3	0.65	0.03	0.31	0.99
5	1	0.69	0.04	0.24	0.97
5	2	0.71	0.04	0.24	0.99
5	3	0.73	0.03	0.23	0.99
5	4	0.74	0.03	0.23	1.00
6	1	0.56	0.04	0.39	0.99
6	2	0.58	0.04	0.37	0.99
6	3	0.60	0.03	0.37	1.00
6	4	0.64	0.02	0.33	0.99

a. Sum of the sensitivity coefficients for TANG and INTANG.
b. The sensitivity coefficient for BFAC.
c. Sum of the sensitivity coefficients for OPCO(1), OPCO(2), and OPCO(3).

For the offshore model, the Kalter-Tyner factor (g) multiplies the operating costs and the investment cost, but does not multiply the lease bonus. Using Eq. (4), the sensitivity coefficient for the Kalter-Tyner factor is the sum of the shares for operating and investment. Thus, the coefficient is equal to 1.0 minus the sum of the lease bonus share and the transportation share. If Eq. (4) is correct, the sensitivity coefficients for KTFAC and REGTRA provide an independent estimate of the lease bonus share and of the sensitivity coefficient for BFAC. Table 12 displays the sensitivity coefficients for BFAC, REGTRA, and KTFAC for all regions and field classes where the replacement cost is less than \$30 and the coefficient for BFAC is not zero. In Table 12, the sums of sensitivity coefficients for BFAC, REGTRA, and KTFAC are all within one percent of 1.00. Thus, Table 12 demonstrates that the sensitivity coefficients for KTFAC and REGTRA can be used to estimate the lease bonus share.

The minimum value for the sensitivity coefficient for KTFAC is 0.20 in region 13 for field class 20. For this case, the lease bonus appears to be responsible for 79% of the replacement cost. To verify that the lease bonus is responsible for 79% of the replacement cost, we will directly estimate the capital and operating shares; the results are displayed in Table 13. As explained in the footnotes for Table 13, the replacement cost shares for capital investment, lease bonus, transportation costs, and operating costs were obtained from the sensitivity coefficients for TANG, INTANG, REGTRA, KTFAC, and XOPCO. Since the sums of the four cost shares are all within one percent of 1.00, Table 13 demonstrates that Eq. (4) can be used to calculate replacement cost shares.

Table 12. Sensitivity Coefficients for BFAC, REGTRA, and KTFAC

Region	Field Class	Sensitivity Coefficients BFAC	KTFAC	REGTRA	Sum
5	15	0.31	0.64	0.04	0.99
5	14	0.21	0.75	0.03	0.99
5	13	0.16	0.80	0.03	0.99
6	15	0.25	0.71	0.03	0.99
6	14	0.17	0.81	0.02	1.00
7	15	0.26	0.71	0.02	0.99
9	14	0.18	0.82	0.00	1.00
11	14	0.21	0.78	0.00	0.99
11	13	0.14	0.86	0.00	1.00
13	14	0.35	0.64	0.01	1.00
13	13	0.24	0.75	0.01	1.00

Table 13. Replacement Cost Shares for Capital Investment, Transportation Cost, Lease Bonus, and Operating Cost for Region Thirteen

Field Class	Replacement Cost Shares Capital[a]	Bonus[b]	Operating[c]	Transport[d]	Sum
20	0.09	0.79	0.11	0.01	1.00
19	0.13	0.74	0.12	0.01	1.00
18	0.15	0.72	0.11	0.01	0.99
17	0.23	0.64	0.12	0.01	1.00
16	0.34	0.54	0.11	0.01	1.00
15	0.40	0.46	0.13	0.01	1.00
14	0.49	0.35	0.14	0.01	0.99
13	0.57	0.24	0.17	0.01	0.99
12	0.66	0.14	0.19	0.00	0.99

a. Sum of the sensitivity coefficients for TANG and INTANG.
b. Determined by the sensitivity coefficients for KTFAC and REGTRA.
c. Sum of the sensitivity coefficients for XOPCO(1), XOPCO(2), and XOPCO(3).
d. Sensitivity coefficient for REGTRA.

In Table 13, the lease bonus share decreases from 79% for field class 20 to 14 % for field class 12. Why does the lease bonus have such a large cost share for field class 20? For field class 20 of region 13, the replacement cost is $7.89 per barrel of oil, the lease bonus is $1.00 per barrel of oil equivalent, and the lead-time is 7 years. The lease bonus is paid in the second year and has a present value of $0.83 (the discount rate is 10% per year). Oil production begins in the eighth year and continues until the twenty-eighth year. For this case, the discounted present value of a barrel of oil sold in the eighth year is $3.68, while the present value of a barrel of oil sold in the twenty-eighth year is $0.55. Thus, the large replacement cost share for the lease bonus is caused by a low replacement cost, a long lead-time and a high discount rate. In Table 13, the lease bonus share decreases as the field class number decreases. The decrease in lease bonus share is caused by both increases in replacement cost and decreases in the lease bonus.

Using Eq. (4), the sensitivity coefficient for the discount factor (ϵ_D) is given by:

$$\epsilon_D = LT*(S_k + S_b) \quad ,$$

where LT is the lead-time and S_y is the operating cost share. From the discussion of Table 5, we expected that the sensitivity coefficient for the discount rate should be related to the lead-time. However, in our expression, ϵ_D is less than the lead-time, while in Table 5, ϵ_D is consistently greater than the lead-time. When we derived Eq. (4), we assumed that k and b were constants. Our approximation has resulted in an underestimate of ϵ_D.

Using Eq. (4), the sensitivity coefficient for the royalty rate (r) is given by:

$$\epsilon_r = r*(1 - S_t) / (1-r) .$$

For the onshore model, the royalty rate is r = 0.125 and the transportation cost share is zero. Thus, we expect the sensitivity coefficient to be $\epsilon_r = 0.14$. In Table A-1 of Appendix A, all of the sensitivity coefficients for ROYL are equal to 0.14. For the offshore model, the royalty rate is r = 0.167 and we expect the sensitivity coefficient to be $\epsilon_r = 0.20*(1 - S_t)$. In Table B-1 of Appendix B, the range for the sensitivity coefficients for ROYL (when the replacement cost is less than $30) is from 0.18 to 0.20, with a mean value of 0.20. In Table B-9 of Appendix B, the sensitivity coefficients for ROYL are equal to 0.18 for field classes 19 and 20 of region 5. In Table B-16 of Appendix B, the sensitivity coefficients for REGTRA are equal to 0.08 for field classes 19 and 20 of region 5. Using our analytical expression for the sensitivity coefficient for ROYL, we expect the coefficient to equal 0.18. Thus, Eq. (4) can be used to derive an analytical expression for the sensitivity coefficient for the royalty rate.

When the replacement cost is less than $30, the sensitivity coefficients for the federal income tax rate (FTAX) range from 0.09 to 0.11 for the onshore model and from 0.19 to 0.58 for the offshore model. Thus, the sensitivity coefficients are larger and have a larger variance for the offshore model. To understand why the two models have such different values for the sensitivity coefficients, we will use Eq. (4) to derive the following analytical expression for the sensitivity coefficient for FTAX (ϵ_t):

$$\epsilon_t = \sigma_t * (S_k + S_b) ,$$

where $$\sigma_t = \frac{t}{f}\frac{\partial f}{\partial t} = [t/(1-t)] * [(1-a)/(1-a*t)] .$$

The parameter a simulates reductions in income tax due to interest deduction, accelerated depreciation, and income tax credits. When the parameter a is 0.0, σ_t = t/(1-t) = 0.85 (the income tax rate is t = 0.46). When a = 1.0, σ_t = 0.0. For the onshore model, the sum of the cost shares for capital and lease bonus ranges from 0.60 to 0.81 (see Table 11). For the offshore model in region 13, the sum of the cost shares for capital and lease bonus ranges from 0.80 to 0.88. If a = 0.0, the maximum value for the sensitivity coefficient for the onshore model would be 0.81 * 0.85 = 0.69, while the maximum value for the offshore model would be 0.88 * 0.85 = 0.75. Since the maximum values are 0.11 for the onshore model and 0.58 for the offshore model, the minimum value of the parameter a is greater than zero for both models.

For the onshore regions and resource intervals displayed in Table 11, the values for a range from 0.87 to 0.93. For the onshore model, the parameter a is large and has a small variance, and the sensitivity coefficients for FTAX are small. For offshore region 13 and the field classes displayed in Table 13, the values of a range from 0.40 for field class 20 to 0.83 for field class 12. Thus, the large values for the sensitivity coefficients for FTAX in the offshore model are caused by low values for a.

Why is the parameter a so variable in the offshore model? We conjecture that the reason is the income tax credit. The income tax credit is 10% of the tangible investment (TANG). For region 13, the sensitivity coefficients for TANG vary from 0.05 for field class 20 to 0.35 for field class 12. Thus, the income tax credit is much larger for field class 12 than for field class 20.

All of the results in this section have been for the case where the replacement cost is less than \$30. When the replacement cost is greater than \$30, the inflation factor PRCHG increases the capital costs, the operating costs, and the transportation costs (but not the lease bonus). We will conclude this section by deriving a analytical expression for the replacement cost when PRCHG is active.

We assume that the replacement cost can be subdivided into components (u_i) and that each component has an inflation factor (α_i). Then, the replacement cost (C) is given by:

$$C = \sum_i u_i * [1 + \lambda * \alpha_i * (C - 30)] ,$$

where λ is the parameter for PRCHG (λ=1.0). A typical list of components would be: TANG, INTANG, OPCO, REGTRA, and BFAC. Since the lease bonus is not inflated, the inflation factor (α_i) would be zero for the lease bonus.

The cost shares (S_i) are the fraction of the replacement cost that can be attributed to each component; that is,

$$S_i = u_i * [1 + \lambda * \alpha_i * (C - 30)] / C .$$

Define ϵ_i to be the sensitivity coefficient of the replacement cost with respect to the component u_i; that is,

$$\epsilon_i = \frac{u_i \partial C}{C \ \partial u_i} .$$

Then each sensitivity coefficient (ϵ_i) is given by:

$$\epsilon_i = S_i / (1 - \beta) ,$$

where $\beta = \sum_j u_j * \alpha_j$.

Thus, the sensitivity coefficients are equal to the cost shares divided by a common factor $(1 - \beta)$ that depends on the base cost components (u_i) and the inflation factors (α_i).

The sensitivity coefficient for PRCHG (ϵ_λ) is given by:

$$\epsilon_\lambda = [(C - 30)/C]*[\beta/(1 - \beta)] .$$

Thus, the sensitivity coefficient for PRCHG can be used to calculate β and β can be used to transform the sensitivity coefficients into cost shares.

The sensitivity coefficients for capital investment, lease bonus, and operating costs for the onshore model for region six are displayed in Table 14. For the first four resource intervals, the replacement cost is less than \$30 and the sum of the sensitivity coefficients is equal to 1.0. For the last three resource intervals the replacement cost is more than \$30 and the sum of the sensitivity coefficients increases steadily to 3.20 in resource interval seven.

If we divide the sensitivity coefficients by the sum of the coefficients, we can calculate the cost shares for capital investment, lease bonus, and operating costs. The cost shares are displayed in Table 15. The cost shares for replacement costs that are more than \$30 are consistent with the cost shares for the replacement costs that are less than \$30.

Replacement cost shares for TANG, INTANG, PLATCO, WATRDP, and KTFAC are displayed in Table 16 for offshore region ten. The sensitivity coefficient for PRCHG were used to calculate β and β was used to transform the sensitivity coefficients in Appendix B into cost shares. The sensitivity coefficient for the Kalter-Tyner factor is the sum of the cost shares for capital investment and operating cost. The coefficient for KTFAC increases from 0.47 for field class 20 to 0.90 for field class 14. The cost share for capital investment is the sum of the cost shares for TANG and INTANG and increases from 0.39 for field class 20 to 0.80 for field class 14. The cost share for the platform cost (PLATCO) increases from 0.22 to 0.51. The normalized sensitivity coefficient for the water depth (WATRDP) is 0.88 for field class 14. Thus, the water depth influences 88% of the replacement cost for field class 14.

Table 14. Sensitivity Coefficients for Capital Investment, Lease Bonus, and Operating Cost for the Onshore Model in Region Six

Region	Resource Interval	Sensitivity Coefficients Capital[a]	Bonus[b]	Operating[c]	Sum
6	1	0.56	0.04	0.39	0.99
6	2	0.58	0.04	0.37	0.99
6	3	0.60	0.03	0.37	1.00
6	4	0.64	0.02	0.33	0.99
6	5	1.13	0.03	0.52	1.68
6	6	1.44	0.04	0.60	2.08
6	7	2.23	0.06	0.91	3.20

a. Sum of the sensitivity coefficients for TANG and INTANG.
b. The sensitivity coefficient for BFAC.
c. Sum of the sensitivity coefficients for OPCO(1), OPCO(2), and OPCO(3).

Table 15. Replacement Cost Shares for Capital Investment, Lease Bonus, and Operating Cost for the Onshore Model in Region Six

Region	Resource Interval	Replacement Cost Shares Capital	Bonus	Operating	Sum
6	1	0.56	0.04	0.39	0.99
6	2	0.58	0.04	0.37	0.99
6	3	0.60	0.03	0.37	1.00
6	4	0.64	0.02	0.33	0.99
6	5	0.67	0.02	0.31	1.00
6	6	0.69	0.02	0.29	1.00
6	7	0.70	0.02	0.28	1.00

Table 16. Replacement Cost Shares for TANG, INTANG, PLATCO, WATRDP, and KTFAC for the Offshore Model in Region Ten

Field Class	Replacement Cost Shares TANG	INTANG	PLATCO	WATRDP	KTFAC
20	0.27	0.12	0.22	0.38	0.47
19	0.31	0.13	0.26	0.44	0.52
18	0.38	0.15	0.33	0.57	0.62
17	0.45	0.16	0.39	0.68	0.71
16	0.48	0.19	0.43	0.71	0.76
15	0.48	0.23	0.40	0.69	0.79
14	0.56	0.24	0.51	0.88	0.90

6. CONCLUSIONS

The DOE Fossil Energy program has sponsored research by ORNL and its subcontractor Lewin and Associates, Inc. to develop a set of computer models to forecast the replacement cost of domestic crude oil and natural gas. The Lewin versions of the models are called REPCO while the ORNL versions are called ORION.

This report has presented the results of a sensitivity analysis of the ORION model for the replacement cost of domestic crude oil. An automated sensitivity analysis was performed using a FORTRAN pre-compiler called GRESS. For every equation in the model, GRESS adds new FORTRAN code to analytically calculate the derivative of the replacement cost with respect to each parameter selected for analysis. When the gradient enhanced version of the model is run, it calculates both the replacement costs and the sensitivity coefficients at the same time.

By performing a sensitivity analysis, we can identify important parameters and uncover design flaws. One of the striking features of ORION is that it is a bimodal model; the sensitivity coefficients when the replacement cost is less than $30 are about a factor of two smaller than when the replacement cost is more than $30. The bimodal behavior begins at a replacement cost of $30 when the inflation factor PRCHG is activated in the subroutine ANETPV. When the replacement cost is more than $30, PRCHG is a linear function of price. PRCHG is used to increase the investment and operating costs in ORION. In section 5, we demonstrated that PRCHG increases all of the sensitivity coefficients for a region and resource interval (or field class) by a common factor. More discussion of the impact and magnitude of PRCHG is provided in Appendix C.

For both the onshore and offshore models, the parameter with the largest sensitivity coefficient was the discount rate. The discount rate coefficients for the offshore model are larger than for the onshore model because the lead-times are longer; 3 years for the onshore model and 5 to 15 years for the offshore model. Since the discount rate has both a large sensitivity coefficient and an uncertain value, it is the greatest source of uncertainty in the replacement costs calculated by ORION.

For the onshore regions when the replacement cost is less than $30, the sensitivity coefficients for the discount rate are about 4.0, the coefficients for the production parameters are about 1.0, and the coefficients for the cost parameters are less than 0.4 and are positive. For the offshore regions, the sensitivity coefficients for the discount rate average about 9.0, the coefficients for the production parameters are about 0.2, the coefficients for the cost parameters are less than 0.2, but the coefficients for the federal tax and lease bonus are larger than the coefficients for the onshore model. The Kalter-Tyner factor amplifies the costs of production in stormy regions and has a large sensitivity coefficient.

The sensitivity analysis indicates which input parameters are important and evaluates the structure of the model. For the offshore model, the sensitivity analysis revealed that the costs of production are not part of the input data but are determined by fixed formulas in the subroutine DEVSKD. To allow the model to be adjusted for inflation or new data, the cost parameters should be inputs or should be calculated by formulas that require input parameters.

The validation of the GRESS results for the onshore model found good agreement between the GRESS results and the results of a perturbation calculation. Validation of the GRESS results for the offshore model by comparison with a perturbation calculation found occasional significant differences between the two sets of results. Detailed analysis of a few of the large differences revealed that the cause was the widespread use of step-functions in the offshore model.

Can the use of step-functions be considered a design flaw? For a single project, discrete choices are inevitable and step-functions are appropriate. If a model is forecasting the average replacement costs for many projects in a region, the average behavior should vary smoothly and should not use step-functions. Unless there are compelling arguments in favor of step-functions, the model should be redesigned to give continuous results.

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APPENDIX A

ONSHORE RESULTS

This Appendix displays the detailed results for the sensitivity analysis of the onshore model. A summary of the sensitivity analysis is displayed in Table A-1. Using GRESS, sensitivity analysis was performed for 42 parameters; the first 31 parameters in Table A-1 are input data; the next 10 parameters are intermediate results; the final parameter is related to the structure of the model.

For each of the parameters, GRESS has calculated sensitivity coefficients; the coefficients are the ratio of the percentage change in the replacement cost to the percentage change in the parameter. For each parameter, Table A-1 displays two sets of maximum, minimum, and mean values. The two sets are the 17 replacement costs that are less than $30 and the 20 replacement costs that are greater than $30.

The principal results of the analysis for the onshore model were discussed in Section 2. Tables A-2 to A-34 of this appendix display the sensitivity coefficients by region and by resource interval for 33 of the 42 parameters. The criteria for choosing the 33 parameters was that the mean value for the sensitivity coefficients for the replacement costs that are greater than $30 should be larger in magnitude than 0.10. A dash in a table means that the replacement cost is greater than $199 and no sensitivity coefficients were calculated.

Table A-1. Summary of GRESS Results for the Onshore Model

	Cost < $30			Cost > $30			
k	Max	Min	Mean	Max	Min	Mean	Parameter
1	4.35	2.90	3.82	15.59	6.03	9.51	DISCRT
2	1.39	0.99	1.16	5.01	1.92	2.84	WELLS
3	−0.99	−1.39	−1.16	−1.92	−5.01	−2.84	RESV
4	0.00	−0.98	−0.98	0.00	−3.67	−2.46	LOMULT
5	0.00	−0.98	−0.96	0.00	−2.44	−1.87	PMULT
6	0.43	0.28	0.36	1.34	0.44	0.76	DRILCO
7	0.62	0.09	0.31	2.07	0.21	1.02	IWUL
8	0.42	0.20	0.28	0.88	0.00	0.38	TD
9	−0.20	−0.42	−0.28	0.00	−0.89	−0.38	DS
10	0.36	0.18	0.26	0.96	0.30	0.51	OPRAT
11	0.19	0.16	0.17	0.63	0.23	0.37	DEPLIF
12	0.22	0.06	0.14	0.93	0.19	0.52	DHCOS
13	0.23	0.09	0.14	0.56	0.15	0.27	OPCOS
14	0.14	0.14	0.14	0.54	0.23	0.33	ROYL
15	−0.10	−0.22	−0.13	−0.20	−0.51	−0.31	API
16	0.14	0.10	0.12	0.48	0.15	0.26	EQUICO
17	0.14	0.09	0.12	0.47	0.16	0.24	INFOP
18	0.11	0.09	0.10	0.33	0.13	0.19	FTAX
19	−0.04	−0.20	−0.09	−0.11	−0.80	−0.40	IFLD
20	−0.07	−0.08	−0.08	−0.11	−0.29	−0.17	INCTC
21	0.08	0.06	0.07	0.26	0.09	0.15	INJEQ
22	0.05	0.05	0.05	0.20	0.09	0.12	SEV
23	0.06	0.03	0.05	0.16	0.05	0.09	OPOVHD
24	0.05	0.02	0.04	0.15	0.05	0.10	GARATE
25	−0.02	−0.05	−0.04	−0.03	−0.13	−0.08	PGOR
26	0.04	0.02	0.03	0.08	0.03	0.05	BFAC
27	0.02	0.00	0.01	0.10	0.00	0.09	WPR
28	0.01	0.01	0.01	0.02	0.01	0.01	STAX
29	0.02	0.01	0.01	0.02	0.01	0.01	WATCO
30	0.01	0.00	0.00	0.07	0.00	0.02	GNGRAT
31	0.00	0.00	0.00	0.00	0.00	0.00	DRILL
32	−0.99	−1.39	−1.16	−1.92	−5.01	−2.84	AVDEP
33	−0.89	−1.17	−1.01	−1.27	−4.14	−2.16	FR(1)
34	−0.84	−0.91	−0.87	−1.43	−3.19	−1.98	YPROD
35	0.50	0.25	0.39	1.61	0.57	1.05	INTANG
36	0.32	0.27	0.30	1.10	0.41	0.64	TANG
37	0.29	0.13	0.19	0.53	0.21	0.32	OPCO(2)
38	−0.06	−0.11	−0.09	−0.12	−0.49	−0.25	MPROD
39	−0.04	−0.14	−0.07	0.00	−0.34	−0.16	DELR
40	0.08	0.05	0.06	0.45	0.08	0.19	OPCO(1)
41	0.02	0.01	0.01	0.02	0.01	0.01	OPCO(3)
42	0.00	0.00	0.00	2.11	0.03	0.66	PRCHG

Table A-2. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in DISCRT -Discount Rate

Resource Interval	Region 1	2	3	4	5	6
1	3.89	4.32	3.83	9.17	4.13	3.03
2	3.84	4.35	3.70	10.72	4.16	2.93
3	3.96	4.30	3.71	10.70	4.19	2.90
4	6.70	7.47	6.15	15.41	4.25	3.36
5	7.97	9.30	7.20	-	7.07	6.03
6	10.30	12.65	9.14	-	8.10	7.74
7	-	-	15.59	-	10.85	11.95

Table A-3. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in WELLS - Successful Exploratory Oil Wells

Resource Interval	Region 1	2	3	4	5	6
1	1.33	1.05	0.99	2.46	1.05	1.10
2	1.30	1.10	1.00	2.95	1.16	1.08
3	1.39	1.23	1.06	2.97	1.15	1.27
4	3.15	2.28	1.92	5.01	1.15	1.27
5	2.41	3.08	2.07	-	2.21	3.22
6	3.00	3.25	2.50	-	1.98	2.26
7	-	-	3.99	-	2.36	3.65

Table A-4. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in RESV - New Field & New Pool Reserve Discoveries

Resource Interval	Region 1	2	3	4	5	6
1	-1.33	-1.05	-0.99	-2.46	-1.05	-1.10
2	-1.30	-1.10	-1.00	-2.95	-1.16	-1.08
3	-1.39	-1.23	-1.06	-2.97	-1.15	-1.27
4	-3.15	-2.28	-1.92	-5.01	-1.15	-1.27
5	-2.41	-3.08	-2.07	-	-2.21	-3.22
6	-3.00	-3.25	-2.50	-	-1.98	-2.26
7	-	-	-3.99	-	-2.36	-3.65

Table A-5. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in LOMULT -Small Field Production Profile

Resource Interval	Region 1	2	3	4	5	6
1	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	-2.46	0.00	0.00
4	0.00	0.00	0.00	-3.49	0.00	-0.98
5	0.00	0.00	-1.73	-	0.00	-1.67
6	-2.30	-2.67	-2.17	-	-1.76	-2.08
7	-	-	-3.67	-	-2.37	-3.20

Table A-6. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in PMULT - Large Field Production Profile

Resource Interval	Region 1	2	3	4	5	6
1	-0.95	-0.95	-0.95	-2.14	-0.94	-0.95
2	-0.96	-0.96	-0.95	-2.44	-0.94	-0.95
3	-0.97	-0.98	-0.97	0.00	-0.97	-0.97
4	-1.59	-1.67	-1.63	0.00	-0.97	0.00
5	-1.86	-2.04	0.00	-	-1.61	0.00
6	0.00	0.00	0.00	-	0.00	0.00
7	-	-	0.00	-	0.00	0.00

Table A-7. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in DRILCO - Drilling Cost for a Well

Resource Interval	Region 1	2	3	4	5	6
1	0.39	0.43	0.33	0.88	0.38	0.28
2	0.39	0.43	0.33	0.97	0.37	0.28
3	0.37	0.43	0.33	0.99	0.38	0.28
4	0.55	0.71	0.55	1.34	0.36	0.28
5	0.61	0.80	0.59	-	0.58	0.44
6	0.71	0.97	0.70	-	0.63	0.52
7	-	-	1.12	-	0.80	0.77

Table A-8. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in IWUL - Well Production Tables

Resource Interval	Region 1	2	3	4	5	6
1	0.52	0.21	0.09	0.49	0.20	0.21
2	0.50	0.27	0.10	0.73	0.32	0.19
3	0.62	0.39	0.15	0.83	0.30	0.38
4	2.00	0.90	0.42	2.07	0.33	0.41
5	1.12	1.50	0.52	-	0.90	1.87
6	1.51	1.33	0.64	-	0.58	0.66
7	-	-	0.95	-	0.21	1.24

Table A-9. Percent Change in Oil Price by Regopm amd Resource Interval in Response to a 1% Increase in TD -Total Development Wells

Resource Interval	Region 1	2	3	4	5	6
1	0.25	0.42	0.26	0.81	0.34	0.26
2	0.24	0.40	0.26	0.86	0.30	0.26
3	0.20	0.38	0.25	0.77	0.27	0.23
4	0.22	0.56	0.38	0.88	0.20	0.20
5	0.20	0.48	0.34	-	0.20	0.17
6	0.15	0.36	0.29	-	0.12	0.08
7	-	-	0.23	-	0.00	0.03

Table A-10. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in DS - Successful Development Wells

Resource Interval	Region 1	2	3	4	5	6
1	−0.25	−0.42	−0.26	−0.81	−0.34	−0.26
2	−0.23	−0.40	−0.26	−0.86	−0.31	−0.26
3	−0.20	−0.38	−0.25	−0.77	−0.27	−0.24
4	−0.22	−0.56	−0.38	−0.89	−0.20	−0.20
5	−0.20	−0.48	−0.34	-	−0.20	−0.17
6	−0.15	−0.36	−0.29	-	−0.12	−0.08
7	-	-	−0.23	-	0.00	−0.03

Table A-11. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in OPRAT - Operating Cost Ratios

Resource Interval	Region 1	2	3	4	5	6
1	0.22	0.18	0.30	0.55	0.23	0.36
2	0.22	0.18	0.30	0.62	0.22	0.36
3	0.21	0.18	0.30	0.55	0.22	0.36
4	0.31	0.30	0.50	0.76	0.22	0.32
5	0.35	0.35	0.48	-	0.35	0.50
6	0.37	0.39	0.58	-	0.34	0.59
7	-	-	0.96	-	0.45	0.89

Table A-12. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in DEPLIF - Depreciation Life

Resource Interval	Region 1	2	3	4	5	6
1	0.17	0.17	0.19	0.43	0.17	0.19
2	0.16	0.16	0.18	0.49	0.16	0.18
3	0.16	0.16	0.19	0.47	0.16	0.18
4	0.23	0.27	0.31	0.63	0.16	0.18
5	0.26	0.30	0.33	-	0.25	0.28
6	0.30	0.37	0.39	-	0.27	0.32
7	-	-	0.62	-	0.35	0.48

Table A-13. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in DHCOS - Dry Hole Cost

Resource Interval	Region 1	2	3	4	5	6
1	0.15	0.16	0.09	0.24	0.14	0.06
2	0.17	0.18	0.09	0.32	0.16	0.07
3	0.22	0.20	0.10	0.39	0.18	0.09
4	0.47	0.39	0.19	0.67	0.21	0.13
5	0.62	0.58	0.25	-	0.40	0.34
6	0.88	0.93	0.39	-	0.49	0.51
7	-	-	0.79	-	0.72	0.85

Table A-14. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in OPCOS - Operating Cost for a Well

Resource Interval	Region 1	2	3	4	5	6
1	0.11	0.09	0.16	0.27	0.11	0.23
2	0.11	0.09	0.16	0.30	0.11	0.23
3	0.11	0.09	0.16	0.28	0.11	0.23
4	0.16	0.15	0.26	0.38	0.11	0.20
5	0.18	0.17	0.25	-	0.17	0.32
6	0.19	0.19	0.31	-	0.16	0.37
7	-	-	0.50	-	0.21	0.56

Table A-15. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in ROYL - Royalty Rate

Resource Interval	Region 1	2	3	4	5	6
1	0.14	0.14	0.14	0.31	0.14	0.14
2	0.14	0.14	0.14	0.36	0.14	0.14
3	0.14	0.14	0.14	0.36	0.14	0.14
4	0.23	0.24	0.24	0.51	0.14	0.14
5	0.27	0.30	0.25	-	0.23	0.24
6	0.33	0.39	0.32	-	0.26	0.30
7	-	-	0.54	-	0.35	0.47

Table A-16. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in API - Crude Oil Gravity

Resource Interval	Region 1	2	3	4	5	6
1	-0.19	-0.11	-0.12	-0.27	-0.10	-0.12
2	-0.19	-0.11	-0.11	-0.31	-0.11	-0.12
3	-0.22	-0.12	-0.13	-0.32	-0.12	-0.13
4	-0.36	-0.21	-0.21	-0.45	-0.12	-0.13
5	-0.42	-0.26	-0.22	-	-0.20	-0.23
6	-0.51	-0.33	-0.27	-	-0.22	-0.28
7	-	-	-0.47	-	-0.29	-0.43

Table A-17. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in EQUICO - Equipment Cost for a Well

Resource Interval	Region 1	2	3	4	5	6
1	0.11	0.10	0.14	0.28	0.10	0.14
2	0.11	0.10	0.14	0.31	0.10	0.14
3	0.10	0.10	0.14	0.32	0.10	0.14
4	0.15	0.16	0.24	0.43	0.10	0.14
5	0.17	0.18	0.25	-	0.16	0.22
6	0.20	0.22	0.30	-	0.17	0.26
7	-	-	0.48	-	0.22	0.38

Table A-18. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in INFOP - Waterflood Operating Cost for a Well

Resource Interval	Region 1	2	3	4	5	6
1	0.11	0.09	0.14	0.27	0.12	0.14
2	0.11	0.09	0.14	0.31	0.12	0.13
3	0.10	0.09	0.14	0.27	0.12	0.13
4	0.16	0.16	0.24	0.38	0.11	0.12
5	0.18	0.19	0.23	-	0.18	0.18
6	0.19	0.21	0.28	-	0.17	0.22
7	-	-	0.47	-	0.24	0.33

Table A-19. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in FTAX - Federal Income Tax Rate

Resource Interval	Region 1	2	3	4	5	6
1	0.10	0.10	0.11	0.23	0.10	0.11
2	0.09	0.09	0.10	0.26	0.10	0.10
3	0.09	0.09	0.10	0.24	0.10	0.10
4	0.13	0.15	0.16	0.33	0.09	0.09
5	0.14	0.17	0.17	-	0.14	0.14
6	0.16	0.20	0.20	-	0.15	0.17
7	-	-	0.33	-	0.19	0.25

Table A-20. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in IFLD - Field Production Tables

Resource Interval	Region 1	2	3	4	5	6
1	-0.12	-0.10	-0.04	-0.16	-0.07	-0.04
2	-0.15	-0.11	-0.04	-0.21	-0.09	-0.05
3	-0.20	-0.13	-0.05	-0.30	-0.11	-0.07
4	-0.43	-0.28	-0.11	-0.55	-0.14	-0.11
5	-0.56	-0.45	-0.17	-	-0.28	-0.30
6	-0.80	-0.74	-0.29	-	-0.35	-0.47
7	-	-	-0.62	-	-0.21	-0.77

Table A-21. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in INCTC - Income Tax Credit Rate

Resource Interval	Region 1	2	3	4	5	6
1	-0.08	-0.08	-0.08	-0.19	-0.08	-0.08
2	-0.07	-0.07	-0.08	-0.22	-0.07	-0.08
3	-0.07	-0.07	-0.08	-0.21	-0.08	-0.08
4	-0.11	-0.12	-0.14	-0.29	-0.07	-0.08
5	-0.12	-0.14	-0.15	-	-0.11	-0.13
6	-0.14	-0.17	-0.18	-	-0.13	-0.15
7	-	-	-0.28	-	-0.16	-0.22

Table A-22. Percent Change in Oil Price by Region and Resource Interval Response to a 1% Increase in INJEQ - Injection Equipment Cost for a Well

Resource Interval	Region 1	2	3	4	5	6
1	0.06	0.06	0.08	0.17	0.07	0.08
2	0.06	0.06	0.08	0.19	0.07	0.08
3	0.06	0.06	0.08	0.19	0.07	0.08
4	0.09	0.09	0.13	0.26	0.07	0.08
5	0.09	0.11	0.14	-	0.11	0.13
6	0.11	0.13	0.16	-	0.11	0.15
7	-	-	0.26	-	0.15	0.22

Table A-23. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in SEV - Severance Tax Rate

Resource Interval	Region 1	2	3	4	5	6
1	0.05	0.05	0.05	0.12	0.05	0.05
2	0.05	0.05	0.05	0.13	0.05	0.05
3	0.05	0.05	0.05	0.13	0.05	0.05
4	0.09	0.09	0.09	0.19	0.05	0.05
5	0.10	0.11	0.09	-	0.09	0.09
6	0.12	0.14	0.12	-	0.09	0.11
7	-	-	0.20	-	0.13	0.17

Table A-24. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in GARATE - General & Administrative Rate

Resource Interval	Region 1	2	3	4	5	6
1	0.04	0.04	0.03	0.08	0.04	0.02
2	0.04	0.04	0.03	0.09	0.04	0.02
3	0.04	0.05	0.03	0.10	0.04	0.03
4	0.08	0.08	0.05	0.15	0.04	0.03
5	0.10	0.10	0.06	-	0.07	0.06
6	0.13	0.15	0.08	-	0.08	0.08
7	-	-	0.15	-	0.12	0.13

Table A-25. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in AVDEP - Total Footage per well

Resource Interval	Region 1	2	3	4	5	6
1	-1.33	-1.05	-0.99	-2.46	-1.05	-1.10
2	-1.30	-1.10	-1.00	-2.95	-1.16	-1.08
3	-1.39	-1.23	-1.06	-2.97	-1.15	-1.27
4	-3.15	-2.28	-1.92	-5.01	-1.15	-1.27
5	-2.41	-3.08	-2.07	-	-2.21	-3.22
6	-3.00	-3.25	-2.50	-	-1.98	-2.26
7	-	-	-3.99	-	-2.36	-3.65

Table A-26. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in FR(1) - Successful Finding Rate

Resource	Region					
Interval	1	2	3	4	5	6
1	-1.17	-0.89	-0.92	-2.20	-0.92	-1.05
2	-1.11	-0.92	-0.93	-2.59	-0.99	-1.01
3	-1.13	-1.02	-0.97	-2.50	-0.94	-1.17
4	-2.59	-1.83	-1.73	-4.14	-0.89	-1.11
5	-1.67	-2.34	-1.78	-	-1.66	-2.76
6	-1.93	-2.02	-2.01	-	-1.27	-1.53
7	-	-	-2.90	-	-1.27	-2.43

Table A-27. Percent Change in Oil Price by Region and Resourcel Interval in Response to a 1% Increase in YPROD - Crude Oil Production

Resource	Region					
Interval	1	2	3	4	5	6
1	-0.86	-0.84	-0.84	-1.88	-0.86	-0.89
2	-0.86	-0.84	-0.84	-2.15	-0.87	-0.89
3	-0.88	-0.86	-0.86	-2.14	-0.89	-0.91
4	-1.43	-1.47	-1.44	-3.04	-0.89	-0.91
5	-1.68	-1.80	-1.50	-	-1.47	-1.55
6	-2.05	-2.33	-1.88	-	-1.58	-1.94
7	-	-	-3.19	-	-2.13	-2.97

Table A-28. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in INTANG - Expensed (Intangible) Investment

Resource	Region					
Interval	1	2	3	4	5	6
1	0.42	0.47	0.31	0.85	0.40	0.25
2	0.44	0.48	0.32	1.00	0.42	0.27
3	0.48	0.50	0.33	1.08	0.44	0.29
4	0.85	0.88	0.57	1.60	0.46	0.33
5	1.04	1.14	0.66	-	0.80	0.65
6	1.38	1.61	0.88	-	0.92	0.88
7	-	-	1.57	-	1.28	1.39

Table A-29. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in TANG - Capitalized (Tangible) Investment

Resource Interval	Region 1	2	3	4	5	6
1	0.29	0.29	0.32	0.72	0.29	0.31
2	0.28	0.29	0.32	0.80	0.29	0.31
3	0.27	0.29	0.32	0.81	0.29	0.31
4	0.41	0.47	0.53	1.10	0.28	0.31
5	0.45	0.53	0.57	-	0.44	0.48
6	0.52	0.65	0.68	-	0.48	0.56
7	-	-	1.08	-	0.61	0.84

Table A-30. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in OPCO(2) - Labor and Materials Operating Cost

Resource Interval	Region 1	2	3	4	5	6
1	0.17	0.13	0.23	0.36	0.16	0.29
2	0.16	0.13	0.23	0.38	0.16	0.28
3	0.16	0.13	0.23	0.33	0.16	0.28
4	0.23	0.21	0.37	0.40	0.16	0.25
5	0.24	0.22	0.34	-	0.25	0.38
6	0.23	0.22	0.38	-	0.23	0.41
7	-	-	0.51	-	0.26	0.53

Table A-31. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in MPROD - Natural Gas Production

Resource Interval	Region 1	2	3	4	5	6
1	-0.09	-0.11	-0.11	-0.26	-0.08	-0.06
2	-0.10	-0.11	-0.11	-0.29	-0.08	-0.06
3	-0.10	-0.11	-0.11	-0.32	-0.08	-0.06
4	-0.16	-0.20	-0.19	-0.46	-0.08	-0.07
5	-0.19	-0.24	-0.23	-	-0.14	-0.12
6	-0.25	-0.35	-0.29	-	-0.18	-0.15
7	-	-	-0.49	-	-0.24	-0.23

Table A-32. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in DELR - Development Wells

Resource Interval	Region 1	2	3	4	5	6
1	-0.10	-0.08	-0.04	-0.13	-0.05	-0.04
2	-0.12	-0.09	-0.04	-0.17	-0.06	-0.04
3	-0.14	-0.10	-0.04	-0.22	-0.07	-0.06
4	-0.23	-0.19	-0.08	-0.34	-0.07	-0.07
5	-0.24	-0.23	-0.11	-	-0.08	-0.12
6	-0.23	-0.24	-0.13	-	-0.06	-0.07
7	-	-	-0.14	-	0.00	-0.03

Table A-33. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in OPCO(1) -Fuel Power Operating Cost

Resource Interval	Region 1	2	3	4	5	6
1	0.06	0.05	0.07	0.19	0.06	0.08
2	0.05	0.05	0.07	0.24	0.06	0.08
3	0.05	0.05	0.07	0.22	0.06	0.08
4	0.08	0.09	0.13	0.36	0.06	0.07
5	0.11	0.13	0.13	-	0.10	0.12
6	0.14	0.18	0.21	-	0.11	0.18
7	-	-	0.45	-	0.19	0.36

Table A-34. Percent Change in Oil Price by Region and Resource Interval in Response to a 1% Increase in PRCHG - Inflation Factor in ANETPV

Resource Interval	Region 1	2	3	4	5	6
1	0.00	0.00	0.00	0.49	0.00	0.00
2	0.00	0.00	0.00	0.84	0.00	0.00
3	0.00	0.00	0.00	0.89	0.00	0.00
4	0.03	0.10	0.06	1.93	0.00	0.00
5	0.30	0.47	0.17	-	0.03	0.11
6	0.74	1.11	0.60	-	0.19	0.53
7	-	-	2.11	-	0.80	1.65

APPENDIX B

OFFSHORE RESULTS

This Appendix displays the detailed results for the sensitivity analysis of the offshore model. A summary of the sensitivity analysis is displayed in Table B-1. Using GRESS, sensitivity analysis was performed for 47 parameters; the first 28 parameters in Table B-1 are input data; the next 11 parameters are related to costs; the next 7 parameters are intermediate results; the final parameter is related to the structure of the model.

For each of the parameters, GRESS has calculated sensitivity coefficients; the coefficients are the ratio of the percentage change in the replacement cost to the percentage change in the parameter. For each parameter, Table B-1 displays two sets of maximum, minimum, and mean values. The two sets are the 57 replacement costs that are less than $30 and the 44 replacement costs that are greater than $30.

The principal results of the analysis for the onshore model were discussed in Section 3. Tables B-2 to B-20 of this appendix display the sensitivity coefficients by region and by resource interval for 19 of the 47 parameters. The criteria for choosing the 19 parameters was that the mean value for the sensitivity coefficients for the replacement costs that are less than $30 should be larger in magnitude than 0.10. A dash in a table means that the replacement cost is greater than $199 and no sensitivity coefficients were calculated.

Table B-1. Summary of the GRESS Results for the Offshore Model

	Cost < $30			Cost > $30			
k	Max	Min	Mean	Max	Min	Mean	Parameter
1	16.59	5.77	9.35	28.60	5.65	13.38	DISCRT
2	0.86	0.20	0.53	3.23	0.51	1.58	KTFAC
3	0.58	0.19	0.38	0.74	0.23	0.39	FTAX
4	0.35	0.00	0.22	0.27	0.00	0.19	BFAC
5	−0.06	−0.52	−0.22	−0.12	−1.97	−0.75	WULT
6	−0.04	−0.43	−0.21	−0.04	−2.30	−0.66	RECOIL
7	−0.05	−0.50	−0.21	−0.11	−1.77	−0.69	PMULT
8	0.20	0.18	0.20	0.68	0.15	0.36	ROYL
9	0.63	0.02	0.17	3.35	0.00	0.87	WATRDP
10	0.53	0.04	0.16	1.40	0.00	0.45	DRILDP
11	−0.08	−0.20	−0.15	−0.16	−0.81	−0.38	API
12	0.21	0.03	0.12	1.01	0.11	0.37	DEPLIF
13	−0.01	−0.07	−0.04	−0.04	−0.33	−0.12	INCTC
14	−0.02	−0.06	−0.04	0.00	−0.14	−0.07	PGOR
15	0.08	−0.02	0.03	0.02	−0.15	−0.06	SGOR
16	0.08	0.00	0.02	0.95	0.00	0.29	REGTRA
17	0.07	0.00	0.02	0.08	0.00	0.04	DHOST
18	0.07	0.00	0.02	0.08	0.00	0.04	DFOOT
19	0.03	0.00	0.01	0.10	0.01	0.05	GARATE
20	0.03	0.00	0.01	0.16	0.01	0.05	DDHR
21	−0.00	−0.10	−0.01	−0.00	−0.44	−0.09	ESUCR
22	0.00	0.00	0.00	0.00	0.00	0.00	SEV
23	0.00	0.00	0.00	0.00	0.00	0.00	WPR
24	0.00	0.00	0.00	0.00	0.00	0.00	STAX
25	0.00	0.00	0.00	0.00	0.00	0.00	SALEYR
26	0.00	0.00	0.00	0.00	0.00	0.00	EHOST
27	0.00	0.00	0.00	0.00	0.00	0.00	OPOVHD
28	0.00	0.00	0.00	0.00	0.00	0.00	EFOOT
29	0.34	0.04	0.15	0.97	0.09	0.36	COPRO
30	0.36	0.02	0.13	1.97	0.10	0.52	PLATCO
31	0.08	0.02	0.05	0.18	0.00	0.10	EQICO
32	0.10	0.02	0.05	0.06	0.03	0.04	WFDCO
33	0.12	0.01	0.05	0.37	0.05	0.15	PIPCO
34	0.12	0.00	0.03	0.47	0.00	0.11	COEXP
35	0.12	0.00	0.03	0.63	0.00	0.18	POPN
36	0.12	0.00	0.03	0.63	0.02	0.21	WOPN
37	0.06	0.00	0.02	0.15	0.01	0.05	169000
38	0.02	0.00	0.01	0.08	0.01	0.03	CODRY
39	0.00	0.00	0.00	0.30	0.00	0.12	CODEL
40	−0.25	−0.81	−0.52	−0.51	−3.07	−1.49	YPROD
41	0.44	0.05	0.25	2.09	0.23	0.77	TANG
42	0.35	0.04	0.15	1.08	0.14	0.49	INTANG
43	0.12	0.02	0.06	0.47	0.03	0.18	XOPCO(2)
44	0.10	0.02	0.05	0.06	0.03	0.04	XOPCO(3)
45	0.03	0.00	0.01	0.32	0.01	0.09	XOPCO(1)
46	0.05	−0.07	−0.01	0.00	−0.29	−0.13	MPROD
47	0.00	0.00	0.00	2.18	0.00	0.62	PRCHG

Table B-2. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in DISCRT - Discount Rate

Field Class	Region 1	2	3	4	5	6	7
20	5.65	5.96	9.00	11.94	8.17	7.76	11.97
19	6.01	6.42	10.23	14.58	8.01	7.61	11.68
18	6.84	7.56	14.07	-	7.83	7.44	11.35
17	8.46	10.03	-	-	7.64	7.27	9.89
16	8.43	13.24	-	-	7.41	7.10	10.76
15	14.13	-	-	-	7.06	6.79	9.37
14	-	-	-	-	6.64	6.46	15.69
13	-	-	-	-	6.37	11.23	24.39
12	-	-	-	-	10.80	13.92	-
11	-	-	-	-	10.66	13.29	-
10	-	-	-	-	15.95	-	-

Field Class	Region 8	9	10	11	12	13	14
20	10.80	9.42	12.79	10.55	16.59	10.34	16.20
19	10.54	9.24	12.52	10.34	14.13	9.22	14.65
18	10.25	7.95	11.05	10.05	12.58	10.10	12.96
17	12.44	7.63	14.25	8.77	15.31	8.88	17.21
16	13.81	7.43	15.11	10.24	16.70	8.60	17.72
15	14.67	7.14	17.47	9.13	-	7.43	22.29
14	28.60	6.80	21.99	7.97	-	6.90	-
13	-	13.12	-	6.80	-	6.31	-
12	-	13.55	-	11.79	-	5.77	-
11	-	16.88	-	14.34	-	9.16	-
10	-	-	-	-	-	13.66	-

Table B-3. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in KTFAC - Kalter-Tyner Factor

Field Class	Region 1	2	3	4	5	6	7
20	0.51	0.62	0.96	1.30	0.31	0.38	0.33
19	0.60	0.73	1.18	1.70	0.35	0.43	0.39
18	0.79	0.98	1.83	-	0.41	0.48	0.46
17	1.12	1.47	-	-	0.47	0.55	0.60
16	1.38	2.08	-	-	0.57	0.64	0.59
15	2.58	-	-	-	0.64	0.71	0.71
14	-	-	-	-	0.75	0.81	1.44
13	-	-	-	-	0.80	1.51	2.95
12	-	-	-	-	1.53	1.94	-
11	-	-	-	-	1.91	2.46	-
10	-	-	-	-	3.15	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.46	0.44	0.47	0.32	0.32	0.20	0.32
19	0.53	0.47	0.52	0.37	0.43	0.25	0.43
18	0.60	0.55	0.62	0.44	0.57	0.27	0.57
17	1.01	0.62	0.95	0.55	1.01	0.35	0.76
16	1.03	0.69	1.12	0.60	1.43	0.45	1.07
15	1.43	0.75	1.26	0.69	-	0.53	1.85
14	3.23	0.82	2.03	0.78	-	0.64	-
13	-	1.69	-	0.86	-	0.75	-
12	-	1.83	-	1.82	-	0.86	-
11	-	2.51	-	2.48	-	1.57	-
10	-	-	-	-	-	2.49	-

Table B-4. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in FTAX - Federal Income Tax Rate

Field Class	Region 1	2	3	4	5	6	7
20	0.23	0.23	0.29	0.33	0.43	0.40	0.51
19	0.23	0.24	0.31	0.37	0.41	0.38	0.48
18	0.24	0.25	0.37	-	0.39	0.36	0.45
17	0.27	0.30	-	-	0.37	0.33	0.38
16	0.26	0.34	-	-	0.33	0.30	0.38
15	0.35	-	-	-	0.29	0.27	0.32
14	-	-	-	-	0.24	0.22	0.47
13	-	-	-	-	0.21	0.35	0.70
12	-	-	-	-	0.31	0.39	-
11	-	-	-	-	0.32	0.37	-
10	-	-	-	-	0.43	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.43	0.43	0.47	0.50	0.58	0.55	0.58
19	0.41	0.41	0.45	0.47	0.50	0.51	0.51
18	0.38	0.36	0.39	0.44	0.43	0.52	0.43
17	0.44	0.32	0.46	0.37	0.49	0.46	0.53
16	0.44	0.30	0.46	0.37	0.50	0.42	0.49
15	0.45	0.26	0.47	0.31	-	0.37	0.55
14	0.74	0.22	0.54	0.25	-	0.31	-
13	-	0.39	-	0.20	-	0.25	-
12	-	0.36	-	0.34	-	0.19	-
11	-	0.37	-	0.36	-	0.26	-
10	-	-	-	-	-	0.37	-

Table B-5. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in BFAC - Lease Bonus Rate

Field Class	Region 1	2	3	4	5	6	7
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	-	0.00	0.00	0.00
17	0.00	0.00	-	-	0.00	0.00	0.00
16	0.00	0.00	-	-	0.00	0.00	0.00
15	0.00	-	-	-	0.31	0.25	0.26
14	-	-	-	-	0.21	0.17	0.00
13	-	-	-	-	0.16	0.23	0.00
12	-	-	-	-	0.18	0.23	-
11	-	-	-	-	0.15	0.00	-
10	-	-	-	-	0.00	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	-	0.00	0.00
14	0.00	0.18	0.00	0.21	-	0.35	-
13	-	0.27	-	0.14	-	0.24	-
12	-	0.19	-	0.20	-	0.13	-
11	-	0.00	-	0.00	-	0.12	-
10	-	-	-	-	-	0.13	-

Table B-6. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in WULT - Well Ultimate Recovery

Field Class	Region 1	2	3	4	5	6	7
20	-0.34	-0.42	-0.68	-0.92	-0.13	-0.16	-0.09
19	-0.40	-0.50	-0.83	-1.20	-0.16	-0.19	-0.11
18	-0.54	-0.68	-1.30	-	-0.19	-0.23	-0.13
17	-0.76	-1.00	-	-	-0.23	-0.26	-0.14
16	-1.02	-1.52	-	-	-0.25	-0.28	-0.32
15	-1.97	-	-	-	-0.30	-0.33	-0.20
14	-	-	-	-	-0.32	-0.34	-0.31
13	-	-	-	-	-0.49	-0.92	-0.52
12	-	-	-	-	-0.85	-1.08	-
11	-	-	-	-	-1.00	-1.27	-
10	-	-	-	-	-1.40	-	-

Field Class	Region 8	9	10	11	12	13	14
20	-0.12	-0.22	-0.14	-0.13	-0.06	-0.06	-0.07
19	-0.14	-0.24	-0.15	-0.16	-0.07	-0.08	-0.09
18	-0.16	-0.31	-0.17	-0.21	-0.08	-0.11	-0.11
17	-0.23	-0.35	-0.24	-0.27	-0.12	-0.16	-0.17
16	-0.57	-0.37	-0.29	-0.33	-0.16	-0.17	-0.22
15	-0.39	-0.40	-0.75	-0.41	-	-0.24	-0.33
14	-0.70	-0.42	-0.52	-0.47	-	-0.29	-
13	-	-0.87	-	-0.52	-	-0.33	-
12	-	-1.24	-	-1.07	-	-0.39	-
11	-	-1.53	-	-1.26	-	-0.46	-
10	-	-	-	-	-	-0.58	-

Table B-7. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in RECOIL - Field Size

Field Class	Region 1	2	3	4	5	6	7
20	-0.04	-0.05	-0.08	-0.12	-0.07	-0.09	-0.18
19	-0.07	-0.08	-0.14	-0.22	-0.10	-0.12	-0.22
18	-0.13	-0.15	-0.30	-	-0.12	-0.14	-0.28
17	-0.24	-0.31	-	-	-0.16	-0.18	-0.41
16	-0.11	-0.20	-	-	-0.15	-0.18	-0.17
15	-0.28	-	-	-	-0.19	-0.21	-0.43
14	-	-	-	-	-0.31	-0.33	-1.02
13	-	-	-	-	-0.19	-0.37	-2.30
12	-	-	-	-	-0.51	-0.65	-
11	-	-	-	-	-0.77	-0.99	-
10	-	-	-	-	-1.58	-	-

Field Class	Region 8	9	10	11	12	13	14
20	-0.25	-0.13	-0.28	-0.08	-0.18	-0.04	-0.19
19	-0.30	-0.15	-0.32	-0.10	-0.28	-0.06	-0.29
18	-0.36	-0.16	-0.41	-0.13	-0.42	-0.05	-0.43
17	-0.70	-0.20	-0.66	-0.19	-0.82	-0.09	-0.55
16	-0.29	-0.19	-0.74	-0.11	-1.11	-0.06	-0.75
15	-0.86	-0.25	-0.41	-0.14	-	-0.10	-1.42
14	-2.30	-0.31	-1.40	-0.18	-	-0.17	-
13	-	-0.67	-	-0.23	-	-0.27	-
12	-	-0.45	-	-0.58	-	-0.37	-
11	-	-0.84	-	-1.06	-	-0.98	-
10	-	-	-	-	-	-1.78	-

Table B-8. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in PMULT - Oil Production Profile

Field Class	Region 1	2	3	4	5	6	7
20	-0.30	-0.37	-0.59	-0.79	-0.12	-0.15	-0.08
19	-0.36	-0.44	-0.73	-1.04	-0.15	-0.18	-0.10
18	-0.48	-0.60	-1.13	-	-0.18	-0.22	-0.11
17	-0.67	-0.89	-	-	-0.22	-0.25	-0.12
16	-0.91	-1.35	-	-	-0.24	-0.27	-0.31
15	-1.77	-	-	-	-0.29	-0.32	-0.18
14	-	-	-	-	-0.31	-0.33	-0.29
13	-	-	-	-	-0.47	-0.88	-0.47
12	-	-	-	-	-0.82	-1.04	-
11	-	-	-	-	-0.96	-1.22	-
10	-	-	-	-	-1.34	-	-

Field Class	Region 8	9	10	11	12	13	14
20	-0.11	-0.21	-0.12	-0.12	-0.05	-0.06	-0.06
19	-0.13	-0.23	-0.13	-0.15	-0.06	-0.07	-0.08
18	-0.15	-0.29	-0.15	-0.19	-0.07	-0.11	-0.09
17	-0.21	-0.33	-0.22	-0.25	-0.11	-0.15	-0.14
16	-0.54	-0.35	-0.26	-0.31	-0.14	-0.17	-0.19
15	-0.36	-0.38	-0.71	-0.39	-	-0.23	-0.28
14	-0.64	-0.40	-0.47	-0.45	-	-0.28	-
13	-	-0.83	-	-0.50	-	-0.32	-
12	-	-1.19	-	-1.02	-	-0.37	-
11	-	-1.47	-	-1.21	-	-0.44	-
10	-	-	-	-	-	-0.56	-

Table B-9. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in ROYL - Royalty Rate

Field Class	Region 1	2	3	4	5	6	7
20	0.15	0.17	0.24	0.30	0.18	0.19	0.19
19	0.17	0.19	0.28	0.38	0.18	0.19	0.19
18	0.20	0.23	0.40	-	0.19	0.19	0.19
17	0.26	0.32	-	-	0.19	0.19	0.19
16	0.31	0.44	-	-	0.19	0.19	0.19
15	0.54	-	-	-	0.19	0.19	0.19
14	-	-	-	-	0.19	0.19	0.34
13	-	-	-	-	0.19	0.35	0.62
12	-	-	-	-	0.34	0.44	-
11	-	-	-	-	0.41	0.52	-
10	-	-	-	-	0.65	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.19	0.20	0.20	0.20	0.20	0.20	0.20
19	0.19	0.20	0.20	0.20	0.20	0.20	0.20
18	0.19	0.20	0.20	0.20	0.20	0.20	0.20
17	0.27	0.20	0.27	0.20	0.28	0.20	0.25
16	0.28	0.20	0.29	0.20	0.34	0.20	0.29
15	0.34	0.20	0.32	0.20	-	0.20	0.42
14	0.68	0.20	0.45	0.20	-	0.20	-
13	-	0.39	-	0.20	-	0.20	-
12	-	0.41	-	0.41	-	0.20	-
11	-	0.53	-	0.52	-	0.34	-
10	-	-	-	-	-	0.52	-

Table B-10. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in WATRDP - Water Depth

Field	Region						
Class	1	2	3	4	5	6	7
20	0.00	0.00	0.00	0.00	0.03	0.04	0.24
19	0.00	0.00	0.00	0.00	0.04	0.05	0.30
18	0.00	0.00	0.00	-	0.05	0.06	0.36
17	0.00	0.00	-	-	0.07	0.08	0.54
16	0.00	0.00	-	-	0.05	0.06	0.44
15	0.00	-	-	-	0.06	0.07	0.63
14	-	-	-	-	0.10	0.11	1.47
13	-	-	-	-	0.09	0.17	3.35
12	-	-	-	-	0.19	0.24	-
11	-	-	-	-	0.26	0.34	-
10	-	-	-	-	0.48	-	-

Field	Region						
Class	8	9	10	11	12	13	14
20	0.33	0.04	0.38	0.04	0.15	0.02	0.16
19	0.40	0.05	0.44	0.05	0.22	0.04	0.23
18	0.47	0.06	0.57	0.07	0.34	0.04	0.35
17	0.92	0.08	0.91	0.11	0.65	0.08	0.45
16	0.78	0.07	1.04	0.07	0.85	0.04	0.60
15	1.26	0.08	1.09	0.09	-	0.07	1.12
14	3.32	0.10	2.00	0.11	-	0.10	-
13	-	0.22	-	0.15	-	0.15	-
12	-	0.20	-	0.36	-	0.20	-
11	-	0.31	-	0.58	-	0.44	-
10	-	-	-	-	-	0.79	-

Table B-11. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in DRILDP - Total Drilled Depth

Field Class	Region 1	2	3	4	5	6	7
20	0.00	0.00	0.00	0.00	0.04	0.05	0.04
19	0.00	0.00	0.00	0.00	0.06	0.07	0.04
18	0.00	0.00	0.00	-	0.07	0.08	0.05
17	0.00	0.00	-	-	0.08	0.10	0.06
16	0.00	0.00	-	-	0.09	0.11	0.08
15	0.00	-	-	-	0.12	0.13	0.09
14	-	-	-	-	0.13	0.14	0.16
13	-	-	-	-	0.17	0.31	0.26
12	-	-	-	-	0.31	0.40	-
11	-	-	-	-	0.36	0.47	-
10	-	-	-	-	0.55	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.05	0.16	0.08	0.14	0.08	0.06	0.09
19	0.06	0.18	0.08	0.18	0.09	0.08	0.12
18	0.07	0.21	0.09	0.23	0.11	0.10	0.13
17	0.10	0.24	0.14	0.29	0.17	0.14	0.23
16	0.14	0.25	0.17	0.34	0.21	0.17	0.30
15	0.18	0.28	0.24	0.43	-	0.22	0.44
14	0.36	0.31	0.34	0.49	-	0.29	-
13	-	0.66	-	0.53	-	0.36	-
12	-	0.81	-	1.09	-	0.44	-
11	-	1.09	-	1.40	-	0.71	-
10	-	-	-	-	-	1.04	-

Table B-12. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in API - Crude Oil Gravity

Field Class	Region 1	2	3	4	5	6	7
20	-0.33	-0.35	-0.42	-0.50	-0.20	-0.20	-0.19
19	-0.35	-0.37	-0.47	-0.59	-0.20	-0.20	-0.19
18	-0.38	-0.42	-0.62	-	-0.20	-0.20	-0.19
17	-0.45	-0.53	-	-	-0.20	-0.20	-0.19
16	-0.50	-0.68	-	-	-0.20	-0.20	-0.19
15	-0.81	-	-	-	-0.13	-0.14	-0.13
14	-	-	-	-	-0.15	-0.16	-0.34
13	-	-	-	-	-0.16	-0.30	-0.61
12	-	-	-	-	-0.31	-0.39	-
11	-	-	-	-	-0.39	-0.52	-
10	-	-	-	-	-0.67	-	-

Field Class	Region 8	9	10	11	12	13	14
20	-0.20	-0.12	-0.12	-0.13	-0.13	-0.13	-0.13
19	-0.20	-0.12	-0.12	-0.13	-0.13	-0.13	-0.13
18	-0.20	-0.12	-0.12	-0.13	-0.13	-0.13	-0.13
17	-0.28	-0.12	-0.16	-0.13	-0.18	-0.13	-0.16
16	-0.29	-0.12	-0.17	-0.13	-0.22	-0.13	-0.19
15	-0.35	-0.12	-0.19	-0.13	-	-0.13	-0.27
14	-0.70	-0.10	-0.26	-0.10	-	-0.08	-
13	-	-0.20	-	-0.11	-	-0.10	-
12	-	-0.22	-	-0.23	-	-0.11	-
11	-	-0.32	-	-0.33	-	-0.20	-
10	-	-	-	-	-	-0.32	-

Table B-13. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in COPRO - Producing Well Cost

Field Class	Region 1	2	3	4	5	6	7
20	0.10	0.12	0.19	0.26	0.08	0.09	0.06
19	0.12	0.15	0.24	0.35	0.10	0.12	0.07
18	0.16	0.20	0.37	-	0.12	0.14	0.08
17	0.23	0.29	-	-	0.14	0.17	0.09
16	0.29	0.44	-	-	0.16	0.18	0.12
15	0.57	-	-	-	0.20	0.22	0.13
14	-	-	-	-	0.22	0.24	0.22
13	-	-	-	-	0.27	0.51	0.33
12	-	-	-	-	0.49	0.62	-
11	-	-	-	-	0.53	0.69	-
10	-	-	-	-	0.76	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.08	0.16	0.10	0.10	0.04	0.04	0.06
19	0.09	0.18	0.11	0.13	0.05	0.05	0.07
18	0.11	0.21	0.12	0.16	0.06	0.07	0.08
17	0.15	0.24	0.17	0.20	0.09	0.09	0.13
16	0.21	0.26	0.21	0.24	0.11	0.11	0.17
15	0.26	0.28	0.28	0.29	-	0.14	0.25
14	0.48	0.31	0.38	0.33	-	0.17	-
13	-	0.64	-	0.34	-	0.20	-
12	-	0.75	-	0.66	-	0.24	-
11	-	0.97	-	0.79	-	0.33	-
10	-	-	-	-	-	0.42	-

Table B-14. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in PLATCO - Platform Cost

Field Class	Region 1	2	3	4	5	6	7
20	0.10	0.12	0.20	0.29	0.04	0.05	0.14
19	0.11	0.14	0.25	0.37	0.05	0.06	0.17
18	0.15	0.19	0.39	-	0.06	0.07	0.20
17	0.21	0.28	-	-	0.07	0.09	0.31
16	0.27	0.43	-	-	0.09	0.10	0.26
15	0.52	-	-	-	0.11	0.12	0.36
14	-	-	-	-	0.17	0.18	0.86
13	-	-	-	-	0.14	0.26	1.97
12	-	-	-	-	0.30	0.38	-
11	-	-	-	-	0.41	0.53	-
10	-	-	-	-	0.74	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.20	0.07	0.22	0.04	0.13	0.02	0.14
19	0.23	0.07	0.26	0.05	0.20	0.03	0.22
18	0.26	0.09	0.33	0.06	0.30	0.02	0.33
17	0.52	0.11	0.52	0.09	0.57	0.03	0.39
16	0.46	0.11	0.63	0.07	0.97	0.04	0.64
15	0.73	0.14	0.64	0.09	-	0.06	1.23
14	1.94	0.17	1.16	0.12	-	0.10	-
13	-	0.35	-	0.14	-	0.14	-
12	-	0.30	-	0.35	-	0.18	-
11	-	0.45	-	0.55	-	0.41	-
10	-	-	-	-	-	0.74	-

Table B-15. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in DEPLIF - Depreciation Life

Field Class	Region 1	2	3	4	5	6	7
20	0.11	0.13	0.21	0.29	0.05	0.06	0.09
19	0.13	0.16	0.26	0.37	0.06	0.08	0.11
18	0.17	0.21	0.40	-	0.08	0.09	0.13
17	0.24	0.32	-	-	0.10	0.11	0.19
16	0.26	0.39	-	-	0.14	0.15	0.17
15	0.44	-	-	-	0.15	0.16	0.21
14	-	-	-	-	0.17	0.18	0.45
13	-	-	-	-	0.17	0.32	0.95
12	-	-	-	-	0.31	0.39	-
11	-	-	-	-	0.36	0.47	-
10	-	-	-	-	0.58	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.12	0.08	0.13	0.05	0.08	0.03	0.09
19	0.15	0.09	0.15	0.06	0.12	0.04	0.12
18	0.17	0.11	0.19	0.08	0.18	0.04	0.18
17	0.32	0.12	0.29	0.11	0.34	0.07	0.24
16	0.30	0.15	0.34	0.13	0.49	0.11	0.34
15	0.43	0.16	0.37	0.15	-	0.12	0.60
14	1.01	0.17	0.61	0.16	-	0.14	-
13	-	0.34	-	0.17	-	0.16	-
12	-	0.34	-	0.35	-	0.17	-
11	-	0.45	-	0.46	-	0.30	-
10	-	-	-	-	-	0.47	-

Table B-16. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in REGTRA - Transportation Cost

Field Class	Region 1	2	3	4	5	6	7
20	0.74	0.72	0.70	0.72	0.08	0.07	0.05
19	0.73	0.72	0.71	0.78	0.08	0.06	0.04
18	0.71	0.71	0.80	-	0.07	0.06	0.04
17	0.72	0.75	-	-	0.06	0.05	0.03
16	0.75	0.85	-	-	0.05	0.04	0.03
15	0.95	-	-	-	0.04	0.03	0.02
14	-	-	-	-	0.03	0.02	0.03
13	-	-	-	-	0.03	0.04	0.04
12	-	-	-	-	0.04	0.04	-
11	-	-	-	-	0.04	0.04	-
10	-	-	-	-	0.04	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.04	0.01	0.01	0.01	0.01	0.01	0.01
19	0.04	0.01	0.01	0.01	0.01	0.01	0.01
18	0.03	0.01	0.00	0.01	0.00	0.01	0.00
17	0.03	0.01	0.00	0.01	0.00	0.01	0.00
16	0.03	0.01	0.00	0.01	0.00	0.01	0.00
15	0.03	0.00	0.00	0.00	-	0.01	0.00
14	0.04	0.00	0.00	0.00	-	0.01	-
13	-	0.01	-	0.00	-	0.01	-
12	-	0.00	-	0.01	-	0.00	-
11	-	0.00	-	0.01	-	0.01	-
10	-	-	-	-	-	0.01	-

Table B-17. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in YPROD - Crude Oil Production

Field Class	Region 1	2	3	4	5	6	7
20	-0.51	-0.62	-0.96	-1.30	-0.32	-0.38	-0.35
19	-0.60	-0.73	-1.18	-1.70	-0.36	-0.43	-0.40
18	-0.79	-0.98	-1.83	-	-0.41	-0.47	-0.45
17	-1.12	-1.47	-	-	-0.47	-0.53	-0.57
16	-1.38	-2.08	-	-	-0.55	-0.61	-0.56
15	-2.58	-	-	-	-0.62	-0.67	-0.66
14	-	-	-	-	-0.72	-0.75	-1.31
13	-	-	-	-	-0.76	-1.40	-2.67
12	-	-	-	-	-1.44	-1.80	-
11	-	-	-	-	-1.80	-2.27	-
10	-	-	-	-	-2.95	-	-

Field Class	Region 8	9	10	11	12	13	14
20	-0.47	-0.45	-0.47	-0.36	-0.35	-0.25	-0.35
19	-0.52	-0.48	-0.51	-0.40	-0.44	-0.29	-0.44
18	-0.59	-0.54	-0.59	-0.45	-0.56	-0.30	-0.57
17	-0.98	-0.60	-0.88	-0.54	-0.96	-0.37	-0.75
16	-1.00	-0.64	-1.02	-0.58	-1.33	-0.46	-1.02
15	-1.37	-0.69	-1.14	-0.65	-	-0.53	-1.73
14	-3.07	-0.75	-1.81	-0.73	-	-0.62	-
13	-	-1.54	-	-0.79	-	-0.72	-
12	-	-1.66	-	-1.68	-	-0.81	-
11	-	-2.26	-	-2.27	-	-1.46	-
10	-	-	-	-	-	-2.31	-

Table B-18. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in TANG - Capitalized (Tangible) Investment

Field Class	Region 1	2	3	4	5	6	7
20	0.23	0.28	0.44	0.60	0.11	0.13	0.18
19	0.26	0.32	0.54	0.78	0.13	0.16	0.22
18	0.35	0.43	0.82	-	0.16	0.19	0.27
17	0.50	0.65	-	-	0.20	0.23	0.38
16	0.54	0.82	-	-	0.28	0.32	0.36
15	0.90	-	-	-	0.31	0.34	0.44
14	-	-	-	-	0.36	0.38	0.93
13	-	-	-	-	0.35	0.66	1.97
12	-	-	-	-	0.64	0.81	-
11	-	-	-	-	0.75	0.97	-
10	-	-	-	-	1.19	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.25	0.17	0.27	0.11	0.17	0.05	0.18
19	0.30	0.19	0.31	0.13	0.25	0.08	0.26
18	0.35	0.22	0.38	0.17	0.37	0.09	0.37
17	0.65	0.26	0.61	0.24	0.71	0.14	0.50
16	0.63	0.31	0.71	0.28	1.00	0.23	0.70
15	0.88	0.33	0.76	0.30	-	0.25	1.24
14	2.09	0.36	1.26	0.33	-	0.29	-
13	-	0.71	-	0.35	-	0.32	-
12	-	0.70	-	0.72	-	0.35	-
11	-	0.93	-	0.95	-	0.62	-
10	-	-	-	-	-	0.97	-

Table B-19. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in INTANG - Expensed (Intangible) Investment

Field Class	Region 1	2	3	4	5	6	7
20	0.14	0.17	0.27	0.38	0.07	0.09	0.07
19	0.17	0.20	0.35	0.52	0.09	0.11	0.09
18	0.23	0.28	0.57	-	0.11	0.13	0.10
17	0.34	0.43	-	-	0.13	0.15	0.12
16	0.45	0.70	-	-	0.15	0.17	0.15
15	0.94	-	-	-	0.19	0.21	0.18
14	-	-	-	-	0.23	0.24	0.34
13	-	-	-	-	0.28	0.52	0.64
12	-	-	-	-	0.54	0.69	-
11	-	-	-	-	0.66	0.85	-
10	-	-	-	-	1.06	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.10	0.14	0.12	0.09	0.06	0.04	0.08
19	0.12	0.16	0.13	0.11	0.08	0.05	0.10
18	0.13	0.19	0.15	0.15	0.11	0.06	0.13
17	0.21	0.22	0.22	0.19	0.18	0.09	0.19
16	0.26	0.24	0.28	0.22	0.26	0.11	0.27
15	0.35	0.27	0.36	0.27	-	0.15	0.44
14	0.76	0.30	0.55	0.32	-	0.20	-
13	-	0.64	-	0.35	-	0.25	-
12	-	0.78	-	0.74	-	0.31	-
11	-	1.08	-	0.98	-	0.54	-
10	-	-	-	-	-	0.83	-

Table B-20. Percent Change in Oil Price by Region and Field Class in Response to a 1% Increase in PRCHG - Inflation Factor in ANETPV

Field Class	Region 1	2	3	4	5	6	7
20	0.11	0.17	0.47	0.82	0.00	0.00	0.00
19	0.16	0.25	0.68	1.25	0.00	0.00	0.00
18	0.29	0.46	1.37	-	0.00	0.00	0.00
17	0.58	0.93	-	-	0.00	0.00	0.00
16	0.82	1.62	-	-	0.00	0.00	0.00
15	2.18	-	-	-	0.00	0.00	0.00
14	-	-	-	-	0.00	0.00	0.34
13	-	-	-	-	0.00	0.02	1.71
12	-	-	-	-	0.04	0.45	-
11	-	-	-	-	0.42	1.17	-
10	-	-	-	-	1.84	-	-

Field Class	Region 8	9	10	11	12	13	14
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.04	0.00	0.02	0.00	0.06	0.00	0.00
16	0.08	0.00	0.11	0.00	0.32	0.00	0.12
15	0.33	0.00	0.23	0.00	-	0.00	0.70
14	2.01	0.00	0.85	0.00	-	0.00	-
13	-	0.16	-	0.00	-	0.00	-
12	-	0.36	-	0.30	-	0.00	-
11	-	1.20	-	1.14	-	0.03	-
10	-	-	-	-	-	0.95	-

APPENDIX C

INFLATION FACTOR - PRCHG

A potentially important issue is the energy required to produce energy - the net energy issue. As the finite resource of petroleum is extracted from the ground, the oil consumed to extract a barrel of oil could increase to the point where more oil was consumed than produced. If there are no subsidies, the economical limit to oil extraction should be reached before the net energy limit is reached. To insure that there are no oil production subsidies, the replacement cost calculation should have a net energy correction; the oil consumed should have the same price as the oil produced. Although ORION has a net energy correction, in this appendix we will argue that the correction is too large.

In ORION, the present value calculation is performed in the subroutine ANETPV. In ANETPV, all investment and operating costs are inflated by the net energy factor - PRCHG. PRCHG is zero if the replacement cost is less than \$30 and is the price change relative to \$30 otherwise, that is,

$$PRCHG = MAX\ [(PRICE - \$30)/\$30\ ,\ 0],$$

where PRICE is the replacement cost.

The source of the inflation factors is documented in the recent National Petroleum Council report on Enhanced Oil Recovery (see Appendix C of the EOR report). In their report, the NPC plotted historical data on the costs for drilling, equipment and general operation against the oil price and determined the following inflation factors: 0.4 for drilling, 0.3 for equipment, 0.2 for general operation, and 1.0 for fuel. Inspired by the NPC report, the inflation factors in ORION are: 0.35 for investment, 0.2 for labor and materials, 0.3 for water, 1.0 for fuel and power, and 0.5 for oil transportation.

Unfortunately, the NPC study neglected a fundamental economic principle: correlation is not causation. In the last decade, the price of oil increased but at the same time the cost of labor and all goods and services produced by the economy increased. Estimating the inflationary impact of oil price increases cannot be done by corelation. The proper way is to estimate how much crude oil is required (directly or indirectly) to produce the goods and services required to produce oil.

Consider the factor 1.0 for fuel and power. To simplify the analysis, we will assume that fuel and power is leaded gasoline. The price of gasoline is not the same as the price of crude oil at the wellhead. From the wellhead, crude oil is shipped to a refinery. From the refinery, gasoline is shiped to a gas station. The difference between the price of gasoline and the wellhead price of crude oil includes the value added at the refinery, the transportation and trade margins, and the taxes. In 1984, the average wellhead price was $25.87 per barrel and the average gasoline price was $1.13 per gallon or $47.41 per barrel. Thus, the wellhead price of crude oil was 55% of the delivered price of gasoline. We have neglected the indirect consumption of crude oil; some crude oil was required to transport the oil from the wellhead to the gas station. Since the crude oil embodied in power (electricity) is probably much less than 55% of the cost, we have probably overestimated the inflation factor for fuel and power.

We will use input-output analysis to estimate the inflation factors for investment and operating costs. Every five years, the Bureau of Economic Analysis (BEA) of the Department of Commerce prepares a benchmark input-output table for the United States. The two most recent tables are for 1972 and 1977; the 1977 table was published in 1984. To prepare the table, the goods and services produced by the economy are assigned to 537 sectors and the BEA estimates a 537 by 537 matrix of interindustry transactions.

To estimate inflation factors for crude oil production, the relevent sectors are:

8.0000 Crude Oil and Natural Gas.

11.0601 New Oil and Gas Well Drilling.

12.0215 Maintenance of Oil and Gas Wells.

31.0101 Petroleum Refining.

45.0300 Oil Field Machinery.

65.0400 Water Transportation.

65.0600 Pipeline Transportation.

68.0301 Water Supply Systems.

The crude oil sector (8.0000) produces crude oil and includes the costs of fuel, power, labor, materials, water, and returns to capital. The new well drilling (11.0601) and maintenance (12.0215) sectors are the investment costs. The petroleum refining sector produces gasoline and other refined products. Oil field machinery is used to drill wells. Although most domestic oil transportation is by pipeline, oil from Alaska requires ships for part of the trip. Water supply is a major component of the operating costs.

One of the byproducts of an input-output table is the total requirements table, which displays the detailed inputs of goods and services required directly or indirectly to produce each of the 537 commodities. Thus, the total requirements table displays the total amount of crude oil required directly or indirectly to produce any good or service. Hence, the inflation factors for investment and operating costs to produce crude oil can be found in the total requirements table.

The input-output tables were prepared in 1972 and 1977 when the crude oil prices were substantially lower than now (although the difference is rapidly becoming smaller). In 1972 dollars, the wellhead price of crude oil was $3.39 in 1972, $6.12 in 1977, and $12.16 in 1983. To adjust the inflation factors for the change in oil price, we will multiply the 1972 factors by 4.0 and multiply the 1977 factors by 2.0; the results are displayed in Table C-1.

In Table C-1, the inflation factors derived from the I-O tables are compared to the factors used in ORION. For investment, the

Table C-1. Inflation Factors Derived from the Input-Output Tables Compared to the Factors used in ORION.

Units - Dimensionless

Category	1972 I-O Table	1977 I-O Table	ORION
Investment			
New	0.082	0.069	0.35
Maintenance	0.066	0.056	0.35
Operations			
Average	0.035	0.024	0.20
Machinery	0.032	0.038	-
Water	0.070	0.120	0.30
Transportation			
Water	0.132	0.128	0.50
Pipeline	0.152	0.125	0.50

inflation factor used in ORION appears to be high by a factor of five; that is, 0.35 versus 0.07. For labor and materials, the inflation factor used in ORION appears to be high by a factor of eight; that is, 0.20 versus 0.024. For water, the agreement is within a factor of three (0.30 versus 0.12). For transportation, ORION appears high by a factor of four (0.50 versus 0.13). In general, the inflation factors used in ORION appear to be much too large.

To illustrate the impact of PRCHG, we will calculate the replacement costs for the onshore and offshore components of ORION without using PRCHG. The recalculated values for the onshore model are displayed in Table C-2. Since PRCHG has no impact when the replacement cost is less than $30, the values in Table C-2 that are less than $30 are identical to the replacement costs in Table 1 of the main report. The most striking feature of Table C-2 is that none of the values are equal to $199.99; the highest replacement cost is $127. For the West Coast, the cost for the seventh resource interval drops from $199.99 to the more marketable value of $68.

Table C-2. Replacement Cost of Onshore Crude Oil by Region and Resource Interval Without Using PRCHG

Units - $1983 per Barrel

Resource Interval	Region 1	2	3	4	5	6
1	18.34	21.73	21.80	41.68	16.58	18.83
2	20.85	24.49	24.30	47.71	18.74	21.07
3	24.68	27.75	27.30	49.26	21.16	23.96
4	31.09	33.20	31.83	59.38	25.16	26.15
5	38.75	42.22	35.10	75.60	30.94	33.70
6	47.39	52.14	44.75	97.38	35.74	43.87
7	68.03	72.43	60.49	126.95	47.77	58.00

The impact of PRCHG on the offshore replacement cost is displayed in Table C-3. The impact of PRCHG for the offshore calculation is not as dramatic as for the onshore case. However, the replacement costs are significantly lower in Table C-3. In Table 3 of the main report, only two of the 14 replacement costs for field class 10 are less than $199.99. In Table C-3, five of the 14 are less than $199.99. For region 5 and field class 10, the replacement cost drops from $146 to $63; a significant decrease.

Table C-3. Replacement Cost of Offshore Crude Oil by Region and Field Class without using PRCHG

Units - $1983 per Barrel

Field Class	Region 1	2	3	4	5	6	7
20	35.13	38.27	48.47	56.50	9.80	11.00	15.56
19	37.60	41.01	53.14	62.70	10.51	11.97	17.08
18	42.45	47.00	63.30	72.50	11.48	13.30	19.24
17	49.97	56.34	78.96	91.96	12.82	15.14	23.36
16	54.03	64.39	88.47	104.23	15.69	19.10	25.21
15	67.97	79.03	123.98	147.77	17.47	21.74	29.54
14	87.11	108.70	158.88	199.99	22.01	28.26	45.15
13	115.85	138.50	199.99	199.99	23.64	30.90	66.41
12	161.41	199.99	199.99	199.99	31.31	42.80	113.73
11	199.99	199.99	199.99	199.99	41.95	57.41	199.99
10	199.99	199.99	199.99	199.99	62.62	85.84	199.99

Field Class	Region 8	9	10	11	12	13	14
20	18.82	11.57	19.07	10.54	21.57	7.89	19.45
19	21.38	12.40	21.16	11.38	21.00	7.50	20.93
18	25.03	12.97	24.22	12.69	25.22	8.56	25.37
17	32.69	15.47	31.05	14.28	33.96	8.63	30.18
16	35.11	18.52	36.41	19.75	44.29	10.20	37.70
15	44.53	23.18	42.10	22.91	74.26	10.76	54.63
14	69.48	28.47	57.04	25.86	121.57	12.29	83.94
13	106.03	35.44	85.17	29.93	199.99	15.08	147.53
12	185.92	41.19	135.60	39.06	199.99	21.98	199.99
11	199.99	58.84	199.99	57.10	199.99	31.11	199.99
10	199.99	76.07	199.99	85.72	199.99	50.72	199.99

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