BLM Safety Net Royalty Relief Analysis of Natural Gas and Oil Production and Public Sector Revenues for United States Onshore Federal Lands

Prepared for the Bureau of Land Management Incentives Team
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1. Executive Summary

This document presents the methodology and results of a study completed by the National Energy Technology Laboratory on behalf of the Bureau of Land Management Incentives Team. The purpose of the study was to evaluate the costs and benefits of several proposed royalty relief scenarios on Federal oil and gas leases. Over the course of two years this study group has modeled several potential incentives. This report presents the results of the final set of runs requested by the team.

The study was conducted by running a decline curve model along with an economic evaluation model on a total of 16,515 Federal oil and gas properties. The algorithms used by these models are presented in detail in this report. The data used in the evaluation consisted of monthly oil, gas, and water production for more than 62 thousand producing wells over a thirteen year period. The data used in the study was provided by the Minerals Management Service (MMS) and was incorporated into a database system designed to provide information required by the models.

The Incentives Team, the incentives evaluated, preparation of data, model descriptions, and actual study results are presented here. A series of conclusions and recommendations were discussed and are summarized here.

Conclusions

- Existing royalty relief is not cost effective at current prices.
- Proposed safety net royalty relief proposals will not be revenue generators under any price scenarios evaluated.
- Incremental production due to safety net royalty relief proposals is relatively small as a percent of total production on Federal lands.
- Gas production is not nearly as sensitive as oil production to lower prices in the study range
- It may be effective to include injection days on line when evaluating property for incentive as a means of stimulating additional production
- Proposed energy bill incentives are more cost effective at the lower prices considered, at higher prices they are more expensive than the current royalty structure

Recommendations

- Do not offer royalty relief at high product prices
- Consider inclusion of injection wells in formulating incentive
- Consider more effective trigger prices for product qualification

2. Introduction

This report summarizes the work that the National Energy Technology Laboratory has completed on behalf of the Bureau of Land Management (BLM) Incentives Team. The analyses objectives were to evaluate the benefits and trade-offs of various incentives on Federal oil and gas leases for the next twenty years. The cost and benefits of the incentives are reported in terms of changes in oil and natural gas production, direct Federal revenues, and direct state revenues. A decline curve analysis and economic evaluation has been completed on 16,515 Federal properties containing more than 62 thousand producing wells managed by BLM and is based on monthly historical production from 1990 to 2003.

BLM is responsible for the management and administration of all United States onshore oil and natural gas production. A significant part of this responsibility is the development, evaluation, and proposal of new or modified incentives that might be applied to oil and gas production on Federal Lands that would have a positive impact on U.S. domestic production. In 2002 BLM formed the BLM Incentives Team to conduct a review of existing incentives for oil and natural gas production and to recommend changes or new incentives that would promote domestic production on Federal lands at a reasonable cost. The BLM Incentives Team membership included: Bureau of Land Management Representation from Headquarters and field Offices, The Minerals Management Service (MMS), The Department of Energy Office of Fossil Energy, the National Energy Technology Laboratory (NETL), the State of New Mexico, the State of Wyoming, the State of California, and the State of Oklahoma.
Through a sequence of meetings and conference calls, the Incentives Team defined and developed a series of incentive scenarios. Two of these evaluated are reported in this document.

In July, 2002 BLM began discussions with the Department of Energy's (DOE) National Energy Technology Laboratory (NETL) to determine if NETL models could be applied to detailed BLM data to help quantify possible incentives developed by the BLM Incentives Team. The NETL Strategic Center for Natural Gas and Oil presently maintains, operates, and utilizes two analytical systems for evaluation of programmatic and policy decisions in support of its oil and gas program. These systems are routinely used to set R&D priorities, evaluate technology feasibility, justify program elements, and estimate benefits of various policies, environmental, and other regulatory initiatives for DOE and other agencies. Model components were extracted and modified to create a customized modeling system to accommodate detailed Federal lands data and to represent the nature of the incentives.

3. BLM Incentives Team

The BLM Incentives Team was designed to have representatives from important Federal and State parties to allow for thoughtful consideration of multiple incentive strategies. It was considered important to have representation from State agencies that perform audit on Federal royalties as the States share in the Federal royalty collections from oil and natural gas operations. MMS was a key participant because they maintain royalty collection data. The BLM Incentives Team membership and primary functions are described in Table 1.

ORGANIZATION	FUNCTION
BLM – HQ (Washington)	Team Lead. Provided depth and well type data.
BLM – California	Represented California BLM – Provided data specific to heavy oil cost.
MMS – Mineral Revenue Division	Coordinated data collection, provided monthly production data, injection data, mineral interest, and royalty data.
State of New Mexico	Incentive definition & structure/review.
State of Wyoming	Incentive definition & structure/review. Provided state tax data.
State of Oklahoma	Incentive definition & structure/review
DOE Fossil Energy – HQ	DOE Liaison. Coordinated FE work
DOE/NETL – Morgantown and Tulsa	Conducted model evaluation work

Table 1. BLM Incentives Team Membership and Function.

Through a series of meetings and conference calls the Incentives Team defined and developed a series of incentives which were evaluated at multiple flat prices for this study. The team was chaired by Mr. Rudi Baier with BLM.

Three face-to-face meetings were held and are summarized in Table 1.

Meeting Date/Location	Purpose
July 2002 / Tulsa, OK	BLM presented Analytical Needs/ NETL presented Overview of modeling Tools and Methods.
November 2003 / Tulsa, OK	NETL presented initial results. New Incentives defined.
May, 2004 / Denver, CO	NETL presented series of 37 sensitivity runs. Final run parameters defined.

During the period between face to face meetings conference calls were held to discuss results, progress, and steer the direction of the analyses. A summary of major events is listed in Appendix A.

4. Incentives Evaluated

The Incentives Team initially considered more than 20 different stimuli. They then broke the analysis into two phases. Phase One incentives deal with existing production and extending the life of current production. Phase Two incentives deal with new development and reactivation of abandoned wells. Phase One incentives are the focus of this report. No work has been initiated on analysis of Phase Two incentives.

PHASE ONE

- Safety Net - Marginal Properties (Incentive Team Reference - 1A)
- Safety Net - All Production Reduced Royalty Rate (Incentive Team Reference – 1B)

PHASE TWO

- New Discovery Incentives (Incentive Team Reference – 2)
- New Development Deep Gas (Incentive Team Reference – 3A)
- New Development Tight Gas (Incentive Team Reference – 3B)
- Reactivation Stripper Oil Well Incentive (Incentive Team Reference – 4E)
- Sour Gas Well Incentive (Incentive Team Reference – 4G)

This report covers or relates results for Item 1A the Safety Net – Marginal Properties only. After reviewing preliminary Phase One results at the November 2003 meeting it was determined providing a Safety Net incentive for all production (not just marginal production) would result in a large loss in Federal and State revenue with only minor incremental oil and natural gas production. Therefore the Incentives Team determined that any safety net incentive would have both a production requirement and a price requirement.

4.1. Incentive Design Considerations

Several considerations were given to the Safety Net Incentive design. The primary focus was to balance two often competing goals:

- That the incentive be targeted so that it is only provided to producing properties that absolutely need it to remain economic and on production. This requires tailoring the incentive so that it is frequently evaluated rather than granted to a property and then continuously available despite improved prices or improved production on a property.

- That the incentive be reasonable for BLM, MMS, and industry to administer. This requires that triggering price threshold be clearly defined and based on publicly available information. There was also significant discussion about how burdensome potential incentive production criteria would be to administer, audit, and validate.

Both low prices and low production rates are required to trigger the incentive for a particular property. This avoids granting the incentive for a property in a low production rate period and then having the properties production rate increase. If either the production rate or price trigger is exceeded the incentive is not available for the property.

4.2. Incentive Initiation Criteria

Defines the product prices at which the incentives become effective. Ease of administration is the key to these incentives so published prices of the West Texas Intermediate crude for the oil price and Henry Hub for the natural gas price were recommended by the Incentives Team. There is also a time requirement to make the incentive effective. The incentive will become effective when the average monthly WTI price of oil falls below a threshold for a period of three consecutive months (four consecutive months in the Energy Bill Case) or when the average monthly Henry Hub price for natural gas falls below a threshold price for the same period.

Either price condition can be met for this incentive to be effective. So it is possible to have the incentive effective for oil products alone or natural gas products alone, or for both oil and natural gas products. There is also a rate qualification for each property. The rate qualification is based on a barrel of oil equivalent (BOE) evaluation that considers the sum of oil and gas production. This is just as important as the price qualification and follows a similar qualification period.

4.3. Incentive Abandonment Criteria

Once the incentive has been granted for a property there are clearly defined price, production, and time parameters required to remove the incentive. These match the starting criteria of price and rate qualification. The incentive will be removed when the average monthly WTI price of oil is greater than the threshold price for a period of three consecutive months or when the average monthly Henry Hub price for natural gas is above the threshold price for a period of three consecutive months. The BOE rate qualification will follow the same pattern and three months of high rate will remove the property from the incentive. Again, if the incentive is the energy bill, the time period is four months instead of three. When the incentive is removed for a property (due either to rate or prices) the incentive starting criteria must again be met to reinstate the incentive. In our analyses these threshold prices are not adjusted for inflation.

4.4. Royalty Relief Calculation

The royalty of any property will be defined by the either a flat royalty rate (as in the Energy Bill Case) or by a scale dependent on the properties average rate or prices (as in the State Auditor's Case).

4.5. Run Definition

Two base runs were defined to help analyze the incentives. A Current Royalty Case which was defined to model the current royalty status of each property. The MMS Minerals Revenue Division provided this information. A royalty rate for each property was provided which included existing incentives received by the property (Stripper Well Incentive and/or Heavy Oil Incentive).

The second base case assumed that no existing royalty incentives were available for each property. This is the Constant 12.5% Royalty Case for all properties. For comparison the Constant 12.5% Royalty Case was assumed as a base case in the runs and compared to the Current Royalty Case and all defined Incentive Cases. In this final report there are two defined incentives cases, the energy bill and the energy bill with injection wells.

5. Data Provided

Data for this study was derived from a variety of sources including, MMS-Mineral Revenues Division, the BLM Washington Office, and the State of Wyoming. The primary data source is the MMS Oil and Gas Operations Report (OGOR) data system. The MMS Mineral Revenue Division provided monthly detailed OGOR data on a well by well basis for all onshore U.S. data for the dates from January 1990 to December 2003.

5.1. OGOR Data

Information in this database is collected from Form MMS-4054 which is a three-part form that identifies all oil and gas lease production and dispositions. The form is used for all production reporting on the OCS and for onshore Federal and Native American lands.

Monthly production information is compared with monthly sales and royalty data submitted on Form MMS-2014, Report of Sales and Royalty Remittance (OMB Control Number 1010-0140) to ensure proper royalties are paid on the oil and gas production reported to MMS. MMS uses the information from parts A, B, and C of the OGOR form to track all oil and gas from the point of production to the point of first sale or other disposition.

OGOR, Part A, Well Production: All operators submit part A, Well Production, for each lease or agreement with active wells until such wells are abandoned and inventories are disposed. Each line identifies a well/producing interval combination showing well status; days on production; volumes of oil, gas, and water produced; and any volumes injected during the report month. An example form is given below.

COLUMN HEADER	DESCRIPTION	COMMENTS
Z_CON_NBR	10 digit MMS lease/agreement #	Used as a key to relate data in OGORA,B, and C
Z_PRODN_DT	Production date	Date of reported monthly production.
Z_API_WELL_NBR	API Well Number	12 digit API well number (State, county, sequence, and side track #)
Z_TUB_STR_CD	Tubing String Code	Exp. ‘X’, ‘C’, D’, or ‘T’
Z_WELL_COMPL_CD	Well Completion Interval	Exp. ‘01’ or ‘02’
DESCR	Completion Description	Exp. ‘Prod Gas Completion’, Non Prod Oil Completion’, ‘Water Disposal Well’
CUST_ID		
Z_ACTN_CD	Action Code	Will always be “A” for Add
Z_STATUS	Production Status	Seems to always be ‘ACTV’
Z_DAYS_PRODN	Days on Production	
Z_OIL_PRODN	Monthly Oil Production	Bbls
Z_WTR_PRODN	Monthly Water Production	Bbls
Z_GAS_PRODN	Monthly Gas Production	Mcf

Z_INJC_VOL	Injection Volume	BBls
Z_INJC_PROD_CD	Injection Code	Exp '30'
Z_RSN_CD	Reason Code for Shut in Wells	
Z_MMS_STATUS	MMS Status Code	
Z_OPR_L_A_NAME	Lease / Agreement Name	
NAME1	Primary Operator	
Z_OPR_WELL_NBR	Operator Well Designation	

Table 3. OGOR, Part A. Data elements in Red were used in Analysis

OGOR, Part B, Product Disposition: For any month with production volumes, operators submit part B, Product Disposition, to identify the sales, transfers, and lease use of production reported on part A. A separate line for each disposition shows: (1) The volume of oil, gas, or water; (2) the sales meter or other meter identifier; (3) the gas plant for instances where gas was processed prior to royalty determination; and (4) the quality of production sold.

COLUMN HEADER	DESCRIPTION	COMMENTS
Z_CON_NBR	10 digit MMS lease/agreement #	Used as a key to relate data in OGORA,B, and C
CUST_ID		
Z_PRODN_DT	Production date	Date of reported monthly production.
NAME1	Primary Operator	
Z_API_GRAVITY	API Gravity	Looks very sparse
Z_BTU	BTU content of Gas	
Z_ACTN_CD	Action Code	Will always be "A" for Add
Z_DISPTN_CD	Disposition Code	
Z_GAS_DISPTN_VOL	Gas Disposition Volume	Mcf
Z_FMP_NBR2	Metering Point Code	
Z_STATUS	Production Status	Seems to always be 'ACTV'
Z_FMP_NBR3	Metering Point Code	
Z_OIL_DISPTN_VOL	Oil Disposition Volume	BBL
Z_WTR_DISPTN_VOL	Water Disposition Volume	BBL

Table 4. OGOR, Part B. Data elements in Red were used in Analysis

OGOR, Part C, Product Sales from Facility: The lease operators who store their production before selling it must submit part C, Product Sales from Facility. Separate lines for each product identify the storage facility, sales meter if applicable, quality of production sold, beginning and ending storage inventory, volume of sales, and volumes of other gains and losses to inventory.

COLUMN HEADER	DESCRIPTION	COMMENTS
Z_CON_NBR	10 digit MMS lease/agreement #	Used as a key to relate data in OGORA,B, and C
CUST_ID		
Z_PRODN_DT	Production date	Date of reported monthly production.
NAME1	Primary Operator	
Z_API_GRAVITY	API Gravity	
Z_ACTN_CD	Action Code	Will always be “A” for Add
Z_ADJ_VOL	Adjusted volume	
Z_BGN_INV_VOL	Inventory at beginning of period	BBl
Z_DISPTN_CD	Disposition Code	
Z_END_INV_VOL	Inventory at end of period	BBl
Z_FMP_NBR	Metering point code	
Z_STATUS	Production Status	Seems to always be ‘ACTV’
Z_FMP_NBR3	Metering point code	
Z_PROD_CD		Seems to always be ‘01’
Z_PRODN_VOL	Produced Volume	BBl
Z_SALE_VOL	Sale Volume	BBL

Table 5. OGOR, Part C. Data elements in Red were used in Analysis

In addition to the OGOR data MMS also provided a specialized table containing royalty rate information, current incentive status, and mineral ownership information.

COLUMN HEADER	DESCRIPTION	COMMENTS
PROPERTY	10 digit MMS lease/agreement #	Used as a key to relate data in OGORA,B, and C
ROYRATE	Royalty Rate	Data given as fraction. Beware there are some which seem to be percent.
FEDALLOCATION	Federal Allocation (fraction)	Fraction of property allocated as “Fed”
INDALLOCATION	Indian Lands Allocation (fraction)	Fraction of property allocated as “Indian”
FIB	Federal, Indian, or Both	“F” for Federal only, “I” for Indian only, “B” for both
MULTIRATEPROP	Multirate Property	Logical (True or False)
STRIPPER	Stripper well Provision	Logical (True or False)
HEAVYOIL	Heavy Oil Provision	Logical (True or False)
STARTDATE	Start date of Production	
ENDDATE	End date of Production	
PROVISIONTYPE	Type of Provision	Always “Royalty”
ROYCALCMETHOD	Royalty calculation Method	Either “01”,”02”,”03”,”05”,”11”,”B”,”C”, or”D”
LOWRATE	Low Royalty Rate	
HIGHRATE	High Royalty Rate	
PROVISIONSTARTDATE	Starting date of Provision	Usually same as Start date from above
PROVISIONENDDATE	Ending date of Provision	Always 12/31/9999

Table 6. Royalty Rate, Incentive, and Mineral Interest Information. Data used in Analysis is highlighted in red.

In addition to the above data, the BLM Washington Office provided depth information for each active well API on Federal Lands and the State of Wyoming collected an average State tax rate for each state which was used in the models.

5.2. Data Processing

All BLM and MMS data was consolidated in a series of Microsoft Access Database Files. A Microsoft Visual Basic (VB 6.0) program was written to manipulate the data files and produce the flat text files necessary for the models. The data processing occurred in eight steps.

Step 1

- Step Through OGORA Database
- Copy each Lease/Agreement Number that has any oil and gas production during 2003
- Results in 16,515 unique lease agreements

Step 2

- Take Production Data from BLM- Bob Fields, use TD per Well for 62 thousand wells.
- Link by API well number to OGORA and assign a depth to each lease.
- Of 16,515 leases, missing 805 depths which are defaulted later.

Step 3

- Get Primary Product (for Decline Purposes)
- State & County
- Well Counts
- Days on Line (Producing, Water Injection, Steam Injection)
- API Gravity, BTU content (from OGORB & OGORC)
- %Federal, %Indian, Effective Royalty
- Tag for current Stripper, Heavy Oil, Multi-rate

Steps 4 and 5

- Build depth default data and default depth were necessary.

Step 6

- Default Values
- Record all changes in database
- Checks Federal + Indian <= 100 else change proportionally
- Check Federal + Indian > 0 else set Fed to 100%

- Check Depth > 0 else use County avg. else use State avg.
- Check Effective Royalty > 0 else set to 12.5%
- Check if Oil properties API > 0 else set to 35 degree
- Check if Gas properties BTU > 0 else set to 1000

Steps7 & 8

- Accumulate OGORA production data to leases level.
- Link to Lease properties database
- Write out flat file for the Decline program.

6. BLM Safety Net Royalty Relief Modeling System

6.1. Overview

The system used to model proposed safety net royalty relief scenarios consists of two independent FORTRAN models designed specifically for this application. The first model performs a hyperbolic decline on historical production data in order to predict possible future recovery. The second model performs a cash flow analysis from the prediction made by the first model in order to determine the economic limit of production under various price and cost structures. This model has built into the cash flow a series of different royalty relief scenarios proposed by the BLM Incentives Team.

The system is designed to model all the Federal lands located onshore lower 48 and Alaska. The decline and cash flow analysis is performed at the individual leases/agreements level. Reporting consists of oil, gas, and water production for 20 years into the future along with Federal and state royalties and severance tax collected. Production and royalty collection is broken up into its Federal, Indian, and private components. The results are provided at the lease, state, and total U.S levels of aggregation and are presented as monthly volumes as well as 20 year summary totals.

The effectiveness of any proposed royalty incentive can be evaluated by running a royalty relief scenario at a given 20 year price track as well as running a constant 12.5% royalty and/or a current royalty structure case using the same monthly price track. Results can then be compared using Excel spreadsheet analysis to compare the change in oil and gas produced with the change in royalty collected In effect calculating the "cost" to the state and Federal treasuries of incremental oil produced as a direct result of the proposed incentive.

The next section of this report documents the flow of data through the modeling system previously described. The remaining two sections of this chapter will describe the two models in much greater detail.

6.2. Flow Diagram

Figure 6-1 presents a general flow diagram of the modeling system used in this safety net royalty relief study. The input to the hyperbolic decline model consists of 37 records of data for each lease/agreement. These records contain descriptive data for the lease as well as monthly oil, gas, and water production from January 1990 through June 2003. This file is the end product of the data processing steps described earlier in this document. This file is the only input required by the hyperbolic decline model.

The hyperbolic decline model declines the historical production of the major product (oil or gas) of the lease/agreement being evaluated and produces a 20 year

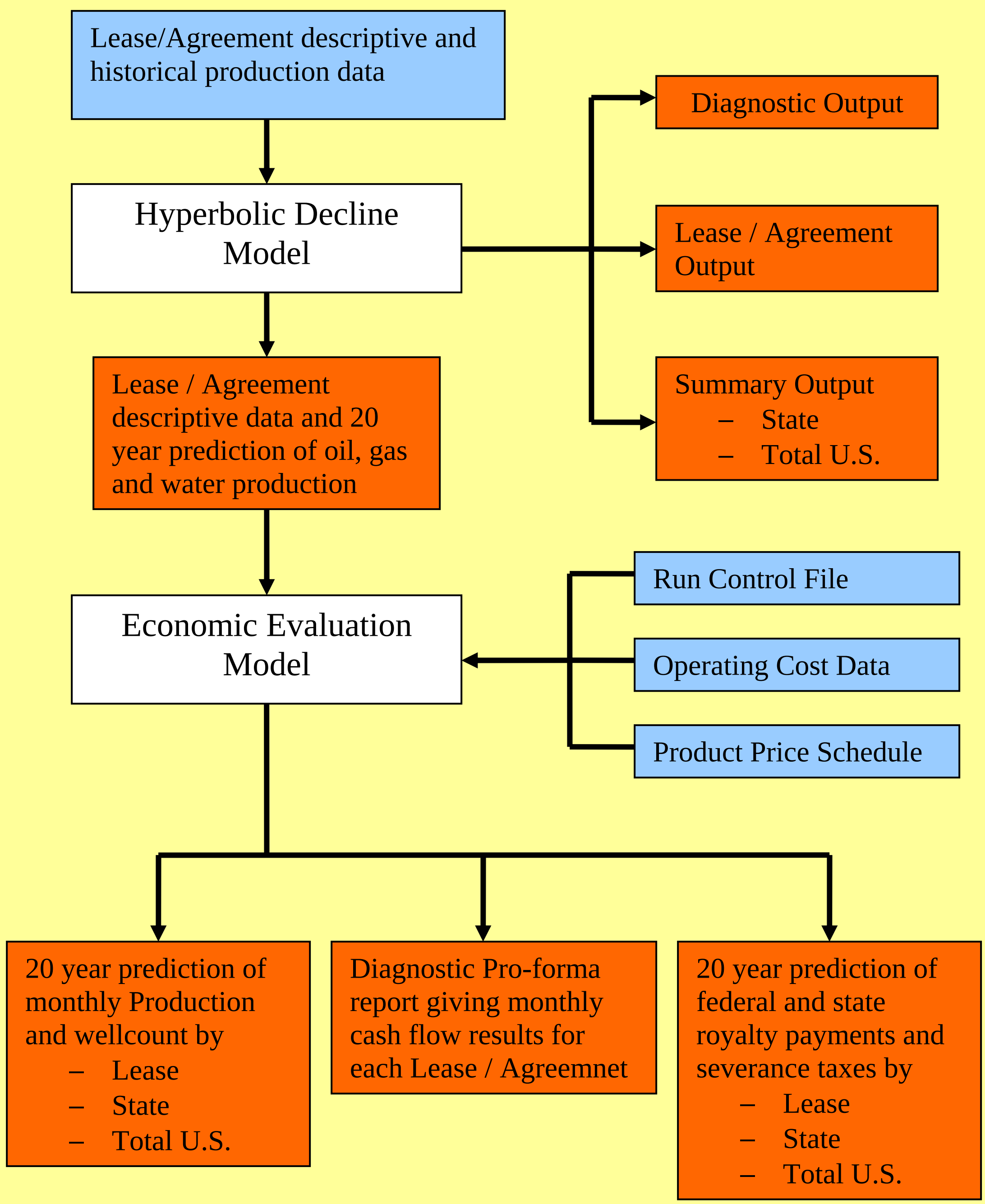

Figure 6-1 – Modeling system flowchart

prediction of monthly production. The 20 year prediction of the secondary product is made by multiplying the major product prediction by either the GOR or Yield of the secondary product. The GOR or Yield is based on historical production. The 20 year prediction of monthly water production is based on applying an estimate of WOR or

WGR to the monthly production of the major product recovered by the lease. The WOR and WGR estimates are base on historical water production.

The primary output consists of a file very similar to the input file. All the same descriptive lease data is passed to the file. The only difference is that instead of historical oil, gas, and water production, the file contains a 20 year monthly prediction of oil, gas, and water production. This file is the primary input required by the economic evaluation model. One file created by the decline model provides diagnostics addressing decisions made by the model in fitting a decline to the historical data. Other files provide monthly production for both historical and predicted data in a form suitable for plotting. This data is provided for individual leases as well as in aggregated form both by individual state and for the entire U.S. The decline model is only run a single time as the output is simply a fit of historical data and does not consider any economics.

Aside from the input file produced by the hyperbolic decline model, the economic evaluation model requires three additional input files. One file contains control information for the run. Important control information consists of things like which royalty relief scenario to run, how long a property is allowed to produce below the economic limit before being shut in, and how long a property is allowed to be shut in before permanently being abandoned. A second file contains a monthly product price track for both oil and gas. The third input file contains information required to calculate operating costs for gas wells and both primary and secondary gas wells.

For each lease/agreement the economic evaluation model does a monthly cash flow analysis which consists of calculating gross revenue, calculating royalty payments based on the desired royalty structure, calculating state production taxes based on individual state rates, calculation of net revenue, and calculation of monthly operating cost based on the product, number and depth of wells, fluid production, and region in which the lease exists. Operating costs are subtracted from net revenue to calculate operating income which determines whether or not the economic limit of the lease has been reached.

Finally, these results are output into a series of files which contain monthly production (oil and gas), well count, and royalty and production tax projections. These results are provided by individual lease, state totals, and U.S. totals. Another output file provides a monthly complete cash flow pro-forma at the individual lease/agreement level.

6.3. Hyperbolic Decline Model

6.3.1. Methodology

The purpose of the hyperbolic decline model is to derive a monthly prediction of oil, gas, and water recovery possible for each lease/agreement over the next 20 years. The model relies on a best fit approach to fit the decline portion of historical production rate data to a hyperbolic production equation. An algorithm is used in order to generate the necessary parameters for the hyperbolic production equation. Once the missing parameters are determined, it is a simple matter to estimate future production by extending the production equation into future years.

The model has a few limitations which are inherent in this type of decline model. First, the predictions are based solely on a decline fit. There is no means of accounting for future stimulation or curtailment of production. Second, the model only fits the decline of the major product (oil or gas) for the lease. Predictions for associated gas and condensate are based on applying fixed values of GOR and Yield determined by analyzing historical production data. The method used is to compare the average GOR or Yield calculated over the decline portion of the history and comparing it to the latest GOR or Yield. The greater of the two is selected. Water production is accounted for in much the same way using a historical WOR for oil leases and a WGR for gas leases. In the case of oil leases, the WOR is increased by 1.14 each year based on the observation of rapidly increasing WOR ratios in the later years of the historical production for oil leases. Another major limitation in this type of model is that a history of declining production is required in order to fit a decline curve equation. In cases in which lease production has not yet begun to decline, a constant percentage decline is assumed for the prediction. The exponential decline rate used in these cases is based on average decline rates observed for the total U.S. Federal lands production over the last few years.

The hyperbolic production equation used in this model is derived as

$$q = \frac{qi}{(1 + n * a_i * t)^{1/n}} \qquad \text{(eq.1)}$$

Where:

q = production rate at time = t
q_i = production rate at time = 0
n = hyperbolic decline exponent
a_i = initial nominal decline rate
t = time

In fitting this equation to historical data there are two decline parameters which are to be determined (a_i and n). The model will attempt three independent algorithms in order to determine the best value for these parameters. Figure 6-2 is a flow diagram of the procedure used by the hyperbolic decline model in order to predict future production for a specific lease/agreement.

Procedure	Step
Define declining portion of historical data which can be fit to hyperbolic decline curve	**STEP 1**
↓	
Use reflective triangle method to determine decline parameters a_i and n	**STEP 2**
↓	
Use linear fit to discretized hyperbolic equation method to determine decline parameters a_i and n	**STEP 3**
↓	
Use iterative substitution method to determine decline parameters a_i and n	**STEP 4**
↓	
Select best set of parameters from steps 2,3, and 4 using method of least squares	**STEP 5**
↓	
Predict future production using hyperbolic production equation	**STEP 1**

Figure 6-2 – Decline Model Logic Flow

6.3.1.1. Step 1 – Define declining portion of historical data

Since only the declining portion of historical data is used to fit the production decline curve, an algorithm is necessary to define the declining data starting point. This is implemented by searching backwards in time for a maximum oil rate. The algorithm used is very simple. The most recent historical production rate is initially set as the maximum. The previous month's production rate is checked. If it is greater than the current max, then it is set to be the current max. If not, a step backwards is taken and the next rate is checked. If after 60 consecutive months are checked and a greater rate is not found, the search is concluded and the current maximum rate is set to be the starting month for the decline data. This month will be defined as time 0 in the three algorithms used to fit decline parameters to the production equation.

6.3.1.2. Step 2 – Reflective Triangle Method

Having defined the historical data to fit to the decline equation, the next step is to estimate the two missing decline parameters. The reflective triangle method was used to determine these parameters. This method can best be explained by pictorially presenting a set of definitions (Figure 6-3) required for following the algorithm. The algorithm is

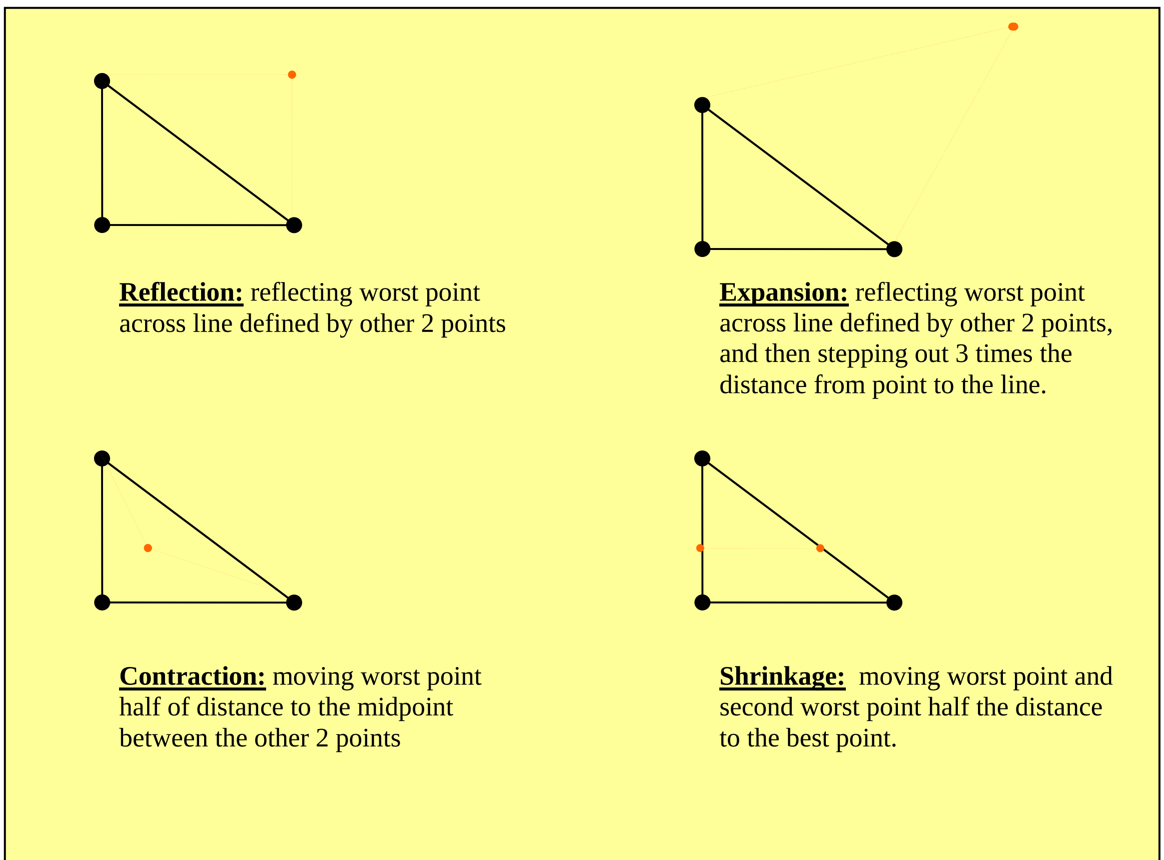

Figure 6-3 – Reflective Triangle Method

then briefly presented in the form of a pseudo code.

1.) Make 3 initial guesses for a_i and n (these form 3 points of a triangle when plotting a_i vs. n on Cartesian paper.
2.) Rank guesses from best to worst fit using minimum residual as selection criteria. A residual is the sum of the squares of the difference between the historical production rates and the production rates calculated using the assumed values of *ai* and *n.*

<u>Perform steps 3 -5 below 100 times or until residual of best and worst fit are within a tolerance of 0.001 %</u>

3.) Calculate reflected vertex and its residual
4.) If reflected vertex is better than worst vertex, then
    i. Calculate expansion vertex and its residual
    ii. If expansion vertex better than worst vertex and reflected vertex, then replace worst vertex with expansion vertex
    iii. ELSE, replace worst vertex with reflection vertex

5.) ELSE,
    i. Calculate contraction vertex and its residual
    ii. If contraction vertex better than worst vertex, then replace worst vertex with contraction vertex.
    iii. ELSE, calculate shrinkage vertex and replace worst vertex with it

6.3.1.3. Step 3 – Discretized linear fit method

1.) Start with differential decline rate equation, rearrange to form a linear equation

$$\frac{a_i q^n}{q_i^n} = -\frac{dq/dt}{q}$$

$$-dq/dt = \frac{a_i q^{n+1}}{q_i^n}$$

$$\ln(-dq/dt) = (n+1)\ln(q) + \ln(a_i / q_i^n)$$

2.) Now have a linear equation of the form
    Y = mX + b
    Where,
    Y = ln(-dq/dt)
    X = ln(q)
    m = n+1
    $b = \ln(a_i / q_i^n)$
3.) Use historical production rates for X values
4.) Discretize (dq/dt) at each production point using central difference approximation to determine a value for Y

5.) Use least squares linear curve fit approach to determine slope(m) and intercept(b) of the line
6.) Directly calculate a_i and n from the calculated slope and intercept

6.3.1.4. Step 4 – Iterative Substitution Method

The third method used to calculate a value for a_i and n can best be described as an iterative substitution method. Once again a pseudo code will be used to describe the algorithm.

<u>DO for I = 1 to NMONTHS where NMONTHS = number of months of historical production</u>

1.) Approximate $a_i = - dq/dt / q$
2.) DO for J = I to NMONTHS
    i. Estimate a value for n
    ii. Using *ai* and *n*, calculate q_j and compare to actual production for month j
    iii. Adjust n up or down depending on whether difference is high or low
    iv. Recalculate q_j and compare to actual production
    v. Iterate steps iii and iv until tolerance achieved or iteration count > 15
3.) Average all of the n values calculated in step 2 to determine n_{avg} for month I
4.) At this point a value of a_i and n for each month of historical production has been identified
5.) Using sum of squares residual error analysis determine best set of decline parameters

6.3.1.5. Step 5 – Select best set of parameters

After the three independent methods have been applied to determine the hyperbolic production decline parameters *ai* and *n*, the next step is to select the best pair of parameters. Each set of parameters is plugged into the hyperbolic decline equation (eq.1) and a residual is calculated . The residual is defined as the sum of the squares of the discrepancies between the actual historical production rates and the rates forecast from the fit to the hyperbolic equation. The pair of decline parameters which yield the smallest residual are used to predict future production.

6.3.1.6. Step 6 – Predict future production

Having selected the decline parameters a_i and n which provide the best fit to historical production data, the final step is to predict 20 years of monthly production data. For each month, the production rate of the lease major product (oil or gas) is determined using eq. 1. The secondary product is then estimated by multiplying the rate of the primary product by the GOR or Yield previously derived from historical data analysis. Future water production is estimated by multiplying the rate of the primary product by either the WOR or WGR which was also derived from historical data analysis.

6.3.2. Input File Descriptions

INPUT.DAT

This file is the only input file required by the hyperbolic decline program. It contains all descriptive data as well as historical monthly oil, gas, and water production from 1/1990 through 6/2003. The following is an itemized list of data elements required for each lease/agreement evaluated. Formatting is such that this data is contained in 43 records per lease. The input contains

Lease Code – 10 digit lease/agreement identifier
State and county code
Major Product (oil or gas)
Well count (producing well count)
API gravity of oil produced
BTU content of natural gas produced
Current royalty rate for lease
Federal allocation (fraction)
Indian allocation (fraction)
Days on line per producing well
Days on line per water injection well
Days on line per steam injection well
Formation depth
Production status (primary, secondary, or steam)
Current Incentive (none, stripper, heavy oil)
Multi-incentive lease (yes or no)
Injection well count
Steam injection well count
Well count used for calculating operating cost
Monthly oil production (bbls) from 1/90 – 6/03
Monthly gas production (mcf) from 1/90 – 6/03
Monthly water production (bbls) from 1/90 – 6/03

6.3.3. Output File Descriptions

Diag.out

This file contains diagnostics for each lease/agreement analyzed by the hyperbolic decline model. The diagnostics consist of the starting month for the decline portion of the historical production data. The hyperbolic decline coefficients (a_i and n) as well as the calculated residual for each of the three decline curve fitting algorithms. The diagnostics specify which methods give the best fit to historical data.

Prediction.out

This file is identical to the input file (INPUT.DAT) with the exception that the historical oil, gas, and water production has been replaced with 20 years of monthly oil, gas, and water predictions. This file contains 61 records for each lease/agreement analyzed.

Decline.out

This file consists of columnar data containing month, historical production rate for lease major product, and production rates derived from decline curve fit of the hyperbolic production equation. The time period covered is from the first month of historical production (1/90) to the last month of prediction (6/23).Output is on a lease/agreement basis and is in a form suitable for creating individual lease plots using Excel.

Summary.out

This file consists of columnar data containing month, oil production, gas production, and water production. The time period covered is from the first month of historical production (1/90) to the last month of prediction (6/23). The rates represent a summary of all leases/agreements analyzed. Output is in a form suitable for creating a summary production plot using Excel.

Stsummary.out

This file is in the exact same format of SUMMARY.OUT except that there is a separate summary production table for each state included in the analysis.

6.4. Economic Evaluation Model

6.4.1. Methodology

The purpose of the economic evaluation model is to estimate the future economic monthly production (oil, gas, and water) for all of the individual leases/agreements being analyzed. The model makes the assumption that the prediction made by the decline model represents production which would occur if economics were not a factor. The model will determine at which point the economic limit (point at which net operating income is less than cost) is reached. This will determine when lease production will be shut-in and when the lease will be abandoned. As part of determining the economic limit of production, the model will calculate royalty payments and severance taxes paid by the operator. This will allow the user to compare production and royalty payments for different assumptions of future product prices, operating costs, and royalty schemes. A

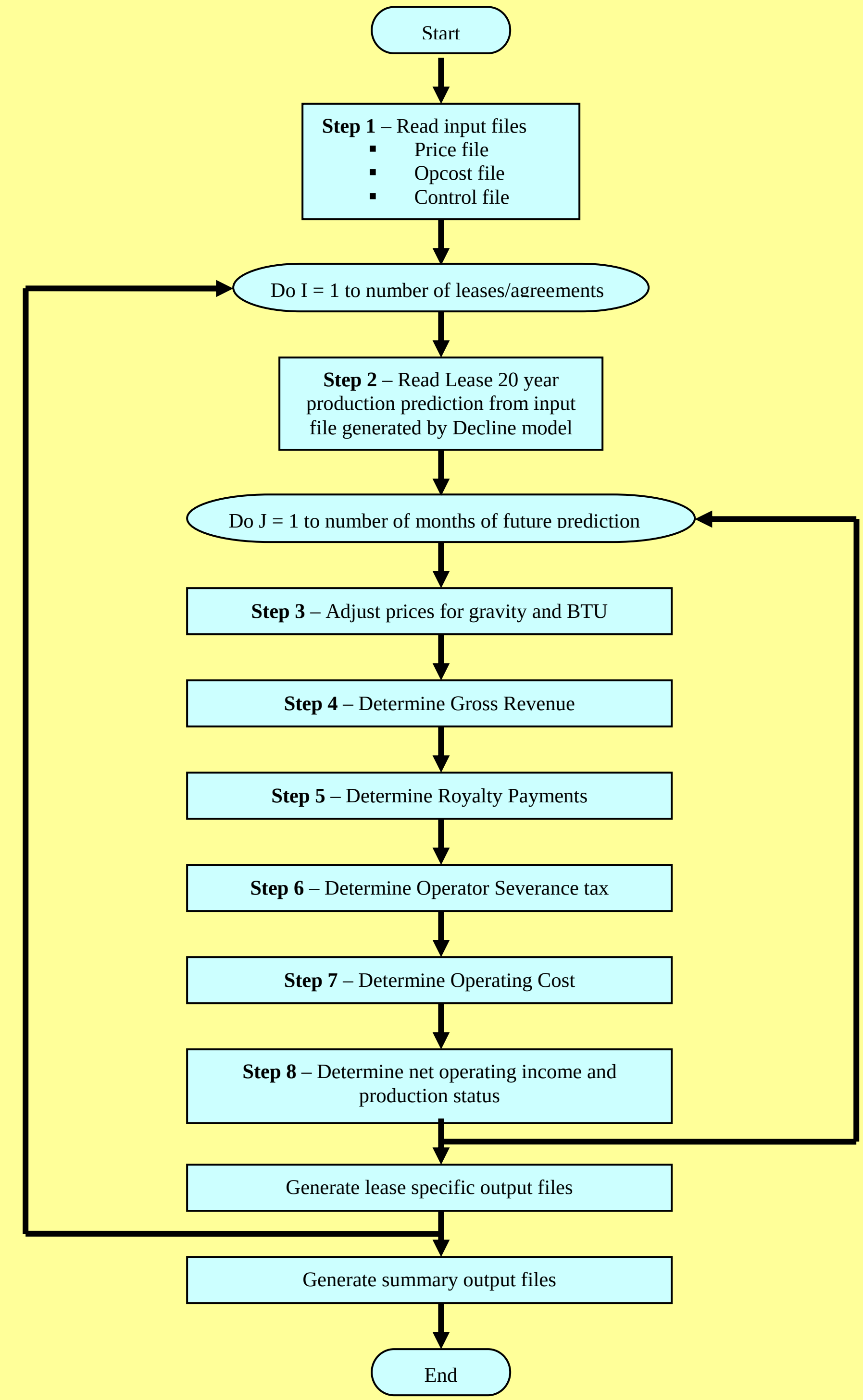

Figure 6-4 – Economic Evaluation Program Logic

separate model run must be made for each price, cost, or royalty scenario. Figure 6-4 presents a flow diagram showing the procedure used by the economic evaluation model in order to estimate future economic production for the leases / agreements being analyzed.

6.4.1.1. Step 1 – Read input files

Program begins by reading ‘price.dat’ file. This file contains future monthly oil ($/bbl) and gas ($/mcf) product prices. Oil prices represent West Texas Intermediate prices and gas prices are Henry Hub prices.

The next file read is ‘opcost.dat’. This file contains important parameters needed to estimate monthly operating costs for a specific lease / agreement. The data provided consists of region based parameters needed to define equations for certain depth dependent oil and gas fixed operating cost equations. Also included are regional values for variable operating costs (costs based on volume of production) and regional values for overhead rate as fraction of cost.

The control file ‘control.dat’ allows the user to select the method of royalty calculation for the run from a list of options. In this file the user also specifies the number of months for which a lease is allowed to produce below the economic limit before being shut in. The file also specifies the number of consecutive months that a lease may be shut in before abandonment.

6.4.1.2. Step 2 – Read lease production prediction

At this step, 61 records which comprise data for a specific lease are read from the file ‘prediction.dat’. These records contain the all descriptive data for the lease as well as 20 years of predicted monthly oil, gas, and water production. This is the file ‘prediction.out’ from the hyperbolic decline model.

6.4.1.3. Step 3 – Correct product prices for gravity and BTU content

Since monthly product prices read from ‘prices.dat’ are specific to WTI and Henry Hub, there is an adjustment to this price based on the specific gravity of the oil or BTU content of the gas. Figure 6-5 shows corrections used for this analysis.

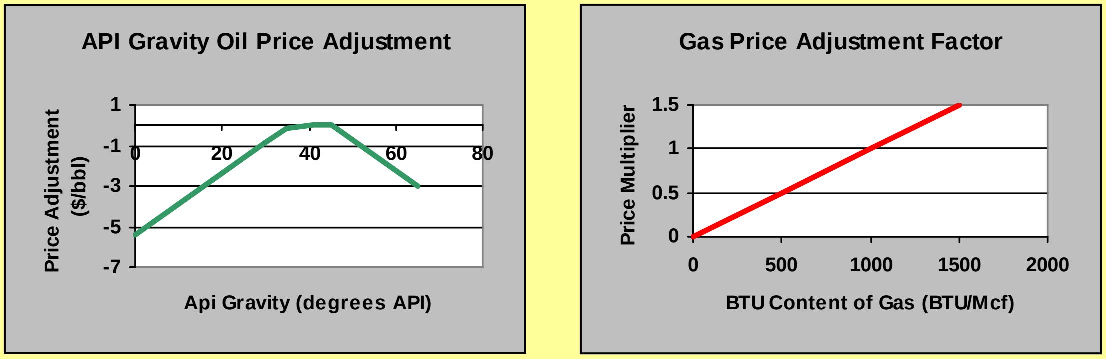

Figure 6-5 – API Gravity and BTU Adjustments

6.4.1.4. Step 4 – Determine Gross Revenue

The monthly production gross revenue stream is determined by summing the monthly adjusted oil price times the monthly oil production with the adjusted gas price times the monthly gas production.

6.4.1.5. Step 5 – Determine Royalty Payments

Through selection using the 'control.dat' file, the user is allowed to select from a list of 5 royalty relief scenarios designed for this study. Most of these have both a rate and price qualification. Those with rate qualifications can be run to either include or not include injection days on line when determining rate.

1) Current Royalty

Price Qualification – N/A

Rate Qualification – N/A

Royalty Rates – Currently imposed rates

2) Constant 12.5 % Royalty

Price Qualification – N/A

Rate Qualification – N/A

Royalty Rates – 12.5 % for both oil and gas production

3) Energy Bill

Price Qualification – Qualifying price is set by user. Several prices ranging from \$15 to \$20 for oil and \$2.00 to \$2.67 for gas have been run in the course of this analysis. Product price must stay below qualifying price for 4 months. Oil and gas royalty rates are independent of each other. Product disqualified for reduced rate if prices stay above threshold for 4 months.

Rate Qualification – Lease calculated per well per day production rate of less than 15 BOE/day. Rate must be maintained for 4 months to qualify. Production rates greater than or equal to 15 BOE/day for 4 months disqualify property from royalty rate reduction

Royalty Rates – Reduced to 5% for qualifying production.

4) Team Safety Net Structure

Price Qualification – Qualifying price is less than \$16 / bbl or \$2.13 / mcf. Product price must stay below qualifying price for 3 months. Oil and gas royalty rates are independent of each other. Product disqualified for reduced rate if prices stay above threshold for 3 months.

Rate Qualification – Lease calculated per well per day production rate of less than 15 BOE/day. Rate must be maintained for 3 months to qualify. Production rates greater than or equal to 15 BOE/day for 3 months disqualify property from royalty rate reduction

Royalty Rates

Price (\$/bbl)	Price (\$/Mcf)	Royalty Rate
> 14 to ≤ 16	> 1.87 to ≤ 2.13	10%
> 12 to ≤ 14	> 1.60 to ≤ 1.87	7%
≤ 12	> 1.60	4%

5) State Auditor's Structure

Price Qualification – Qualifying price is less than \$12 / bbl or \$1.60 / mcf. Product price must stay below qualifying price for 3 months. Oil and gas royalty rates are independent of each other. Product disqualified for reduced rate if prices stay above threshold for 3 months.

Rate Qualification – Lease calculated per well per day production rate of less than 15 BOE/day. Rate must be maintained for 3 months to qualify. Production rates greater than or equal to 15 BOE/day for 3 months disqualify property from royalty rate reduction

Royalty Rates

Price ($/bbl)	Price ($/Mcf)	Royalty Rate
> 10 to ≤ 12	> 1.33 to ≤ 1.60	10%
> 9 to ≤ 10	> 1.20 to ≤ 1.33	9%
> 8 to ≤ 9	> 1.07 to ≤ 1.20	8%
≤ 8	≤ 1.07	7%

Note- These incentive rates apply only to Federal allocation of property. Private and Indian portion of lease is assumed to pay 12.5 % royalty

6.4.1.6. Step 6 – Determine operator severance tax rate

State severance tax rates are approximated by multiplying the value of the working interest portion of the production by the following percentage rates.

State	Percentage
Wyoming	12.5
Utah	9
Colorado	9
New Mexico	8
Texas	6.5
Oklahoma	7.1
Montana	9.26
North Dakota	11.5 (oil) 5 (gas)
Louisiana	12.5
Alaska	7.25

6.4.1.7. Step 7 – Determine Operating Cost

The next step in the model is to determine a monthly operating cost for the lease/agreement. Depending on whether the major lease product is oil or gas, a different set of equations are used to calculate the monthly operating costs. The actual cost equations and other parameters which were used in the safety net royalty relief analysis are presented as part of the description. These regional equations are supplied by the user as part of the 'opcost.dat' file provided as input to the model.

Operating Cost Equations for Oil Leases

Monthly operating cost ($) = (((Per well annual fixed cost) / 12) * number of wells)+ Monthly variable cost + Monthly G&A cost) * Price adjustment factor

Per well annual fixed cost =
Primary production operating cost + Pump operating cost (Primary production leases)

OR Secondary operating cost (waterflood and steamflood leases)

Primary Production Operating Cost = $/well/Year = A0 + (A1 * Depth)

USGS Region	Name	A0	A1
1	Alaska	4420.90	0.327
2	Pacific Coast	4420.90	0.327
3	Colorado Plateau & Basin	4917.70	0.234
4	Rocky Mountains	4917.70	0.234
5	Permian	5028.30	0.325
6	Gulf Coast	8574.30	0.284
7	Mid-Continent	4335.80	0.380
8	Eastern U.S.	3500.00	1.000

Pump Operating Cost = $/well/Year = A0 + (A1 * Depth)

USGS Region	Name	A0	A1
1	Alaska	4491.80	2.322
2	Pacific Coast	4491.80	2.322
3	Colorado Plateau & Basin	6220.80	0.419
4	Rocky Mountains	6220.80	0.419
5	Permian	5168.10	0.528
6	Gulf Coast	9001.10	0.435
7	Mid-Continent	5547.0	0.520
8	Eastern U.S.	14000.00	0.780

Secondary Operating Cost = $/well/Year = A0 + (A1 * Depth)

USGS Region	Name	A0	A1
1	Alaska	19702.40	4.587
2	Pacific Coast	19702.40	4.587
3	Colorado Plateau & Basin	22850.00	3.961
4	Rocky Mountains	22850.00	3.961
5	Permian	22747.40	4.804
6	Gulf Coast	40738.20	5.808
7	Mid-Continent	18895.10	5.022
8	Eastern U.S.	20000.00	5.000

Monthly variable cost = $0.10 per bbl. of fluid produced (oil and water)
Additional Steamflood cost = (1.6 * Gas Price) per bbl of oil produced
Monthly G&A Cost = 0.20 * (Annual Fixed Cost + Annual Variable Cost)

Price Adjustment Factor = 1.0 + (0.2 * ((WTI PRICE – 30.) / 30.))

Operating Cost Equations for Gas Leases

Monthly operating cost ($) = (((Per well annual fixed cost) / 12) * number of wells)+ Monthly variable cost + Monthly G&A cost) * Price adjustment factor

Per well annual fixed cost = Primary production operating cost

Primary Production Operating Cost = $/well/Year = A0 + (A1 * Depth)

Supply Region	Name	A0	A1
1	Appalachia	1003.10	0.400
2	Miss/Ala/Florida	8364.10	2.000
3	Midwest	8364.10	2.000
4	Arkansas East Texas	6154.00	2.380
5	South Louisiana	8801.00	1.910
6	Texas Gulf Coast	6721.00	2.120
7	Permian	6648.00	1.870
8	Mid-continent	7950.20	2.040
9	San Juan	8364.10	2.000
10	Rockies Farland	10821.00	2.250
11	Williston Basin	8364.10	2.000
12	Pacific Onshore	8364.10	2.000
13	Alaska	250757.00	0.000

Annual variable cost = $0.10 per bbl. of fluid produced (condensate and water) +
$0.55 per Mcf of gas produced

Annual G&A Cost = 0.20 * (Annual Fixed Cost + Annual Variable Cost)

Price Adjustment Factor = 1.0 + (0.2 * ((Henry Hub PRICE – 2.) / 2.))

Note that in both the oil as well as gas operating cost calculations, the annual fixed cost is calculated on a per well basis and is then multiplied by the number of wells. This well count is not the actual number of producing wells but is modified to reflect the existence of dual and triple completions which cost more to operate than single completion wells. A single completion well counts as 1 well for purpose of calculating annual fixed cost. A dual completion well counts as 1.5 wells, and a triple completion well counts as 1.75 wells.

6.4.1.8. Step 8 – Determine Operating Income and Production Status

Net operating income is then determined using the following equation.
Net operating income = Gross revenue – Royalty payments – Severance tax –operating costs

If net operating income is a positive number then the lease is considered to be economic for the current month. If net operating income is less than or equal to zero, the lease is considered uneconomic for the current month and a count of the number of consecutive uneconomic months is begun. After a number of consecutive uneconomic months set by the model user in ‘Control.dat’, the lease is shut-in and production becomes zero. If the lease is shut-in for more than the maximum number of shut-in months (also user defined), the lease will be abandoned and will no longer produce regardless of future economics.

6.4.2. Input File Descriptions

Prediction.dat

This file is simply the rename file ‘Prediction.out’ which was produced by the hyperbolic decline model. It contains lease specific descriptive data along with 20 years of predicted monthly oil, gas, and water predictions.

Price.dat

This file contains 20 years (240 months) of predicted West Texas Intermediate oil prices in ($/bbl) as well as 240 months of predicted Henry Hub gas prices in ($/mcf)

Control.dat

The control file provides the model with three pieces of run control information from the user. The file contains the number from an itemized list of the desired royalty relief scenario to model. It also contains the number of months of production below the economic limit before wells are shut-in as well as the number of months wells are shut-in before being abandoned.

Opcost.dat

This file contains all information needed by the model to estimate monthly lease operating costs. The file is composed of a series of tables which provide regional cost coefficients necessary to define several types of cost equations. For oil equations, the regions used are the 8 USGS defined regions. For gas equations, there are separate coefficients for 13 supply regions. The costs defined by the series of tables are:

1. Fixed cost for oil secondary production
2. Fixed cost for oil primary production excluding pump costs

3. Fixed incremental cost for operating pumping units
4. Oil variable operating cost
5. Oil G&A rate
6. Fixed cost for gas primary production
7. Gas variable operating cost
8. Gas G&A rate

Toris_regions.dat

This file provides a list of all possible 5 digit State/County codes along with the following information, State name, county name, USGS region number, and USGS region name. The purpose of this file is to provide a crosswalk for the model between State/County code which is provided in MMS data and the USGS region number which is necessary for operating cost calculations for oil leases.

Gsam_regions.dat

This file provides a list of all possible 5 digit State/County codes along with the following information, State name, county name, supply region number, and supply region name. The purpose of this file is to provide a crosswalk for the model between State/County code which is provided in MMS data and the supply region number which is necessary for operating cost calculations for gas leases.

6.4.3. Output File Descriptions

Proforma.out

This file is primarily used as a tool for model checking and debugging. It provides details on a monthly basis for all of the cash flow elements which go into the calculation of monthly net operating income for each lease/agreement. The elements provided in this file include monthly oil and gas prices, API gravity and BTU adjusted oil and gas prices, gross revenue, total royalty, severance tax, operating cost, net operating income, shut-in status, and abandonment status.

Oneliner.out

The one liner file is designed to allow the user to quickly rank leases by their potential or lack of potential. It provides relevant summary information in a single line for each analyzed lease/agreement. The data output for each lease consists of total predicted production over the next 20 years, the total amount of royalty to be paid over the 20 years, and the month in which the lease will be abandoned based on the model run projections.

Prod.out

File ‘prod.out’ contains detailed production data on a monthly basis for each lease/agreement. Output consists of both oil and gas production. The production is broken out into Federal, Indian, and private allocations. The twenty year summary production is also provided for each lease.

Roycost.out

This file contains detailed royalty and severance tax information on a monthly basis for each individual lease/agreement. Output consists of WTI and Henry Hub prices for the month along with adjusted oil and gas prices, royalty payments and severance tax payments. Royalty payments are broken out into Federal, Indian, and private allocations. Summary royalty and severance payments for the next twenty years are reported for each lease.

Well.out

The well file ‘well.out provides information on the number of active producing wells for on a monthly basis for each individual lease/agreement. A total producing well count estimated by the model prediction is reported along with breakout of the well count into Federal, Indian, and private allocations.

Sumprod.out, Stsumprod.out

These files provide the same data elements as file ‘prod.out’. The only difference is that they report summaries instead of individual leases/agreements. ‘Sumprod.out’ provides a national monthly production summary while ‘Stsumprod.out’ provides monthly production summaries by state.

Sumroycost.out, Stsumroycost.out

These files provide the same data elements as file ‘roycost.out’. The only difference is that they report summaries instead of individual leases/agreements. ‘Sumroycost.out’ provides a national monthly summary of royalty and severance payments while ‘Stsumroycost.out’ provides monthly summary reports by state.

Sumwell.out, Stsumwell.out

These files provide the same data elements as the file ‘well.out’ The only difference is that they report summaries instead of individual leases/agreements.
‘Sumwell.out’ provides a national monthly summary of producing well count while ‘Stsumwell.out’ provides monthly summary reports by state.

7. Results of BLM Safety Net Royalty Relief Analysis

7.1. Analysis Overview

The final set of analyses requested by the Incentives Team consisted of 26 model runs. These runs were used to analyze the expected costs and benefits of two safety net royalty relief proposals. The two proposals being considered are the "energy bill" and the "energy bill" with injection wells included. A current royalty case was also run in order to contrast the proposed royalty incentives with the heavy oil and stripper incentives in place today. A constant 12.5% royalty case was run to compare with the incentive runs so that the incremental costs and benefits of the royalty relief packages could be determined. The following table provides a matrix of the model runs which were performed for the analysis.

Oil Price ($/Bbl)	Gas Price ($/Mcf)	Constant 12.5% Royalty	Current Royalty Structure	Energy Bill	Energy Bill with Injection
35.00	4.67	X	X		
20.00	2.67	X	X	X	X
18.00	2.40	X	X	X	X
16.00	2.13	X	X	X	X
15.00	2.00	X	X	X	X
13.00	1.73	X	X	X	X
11.00	1.47	X	X	X	X

The four royalty cases were run using a total of seven constant monthly price tracks. The ratio between oil and gas prices was maintained at 7.5 for each price track. This ratio is derived from the $15.00 and $2.00 price thresholds proposed in the original draft of the energy bill. No runs were made for the proposed energy bill cases using the $35 price track since it was not conceived that the threshold oil price for royalty relief would ever be above $20 per barrel.

The remainder of this chapter presents the results of these runs. First the results of the decline curve fit are presented and discussed. Results of the economic model runs are then presented for each of the four royalty scenarios. Monthly production predictions are presented graphically and 20 year summary results are presented in tabular form. Another section presents the results as incremental to the constant 12.5% royalty case. This will allow for a determination of the costs and benefits of the proposed incentives in relation to currently operating royalty structure. The final section presents a list of conclusions and recommendations generated by analysis of these results.

7.2. Decline Model Analysis

7.2.1. Decline Model Predictions Discussion

The hyperbolic decline model was run using historical oil, gas, and water production collected for 16,515 Federal oil and gas leases/agreements which reported active production for June, 2003. Data generation was described earlier in this report. Monthly historical production data was used from January of 1990 thru June of 2003. Each lease was analyzed separately by the model which fit a hyperbolic curve through the historical data and made a 252 month (21 year) prediction of oil, gas, and water production based on the curve fit. The prediction was made for 21 years in order that there would be 20 years of predicted production beyond the current date of July, 2004. This 20 year prediction will form the economic model input.

Section 7.2.2 below presents the summary results of the hyperbolic decline analysis for the 16,515 Federal leases/agreements in graphical form. Figure 7-1 presents a graph of the historical and predicted oil production on Federal leases. Two plots are shown on Figure 7-1. The first shows historical and predicted oil production for all Federal leases, the second shows historical and predicted oil production for only those leases which were already producing in January, 1990 (the first month of production history). The reason for showing this second plot is to allow the user to better judge the quality of the hyperbolic decline fit. By looking only at leases which produced throughout the entire historical time frame, the distortion caused by the fact that new leases are being added to the historical production every year is removed. No attempt is made by the model to predict development of new leases. Therefore, in the curve showing all leases, the prediction seems to decline more rapidly than the historical production because only those leases which exist in June, 2003 are declined. No projections are made for new leases which might come on in the next 20 years.

This effect shows up even more drastically in the plots of historical and predicted gas production on Federal leases (Fig. 7-2). This is because most of the new development in the last few years has involved gas leases, especially coalbed methane. Figure 7-3 presents historical and predicted water production from Federal leases. These curves are based on water oil ratios for the oil leases and gas water ratios for the gas leases. The gas water ratio is assumed to remain constant for the prediction period while the water oil ratio is assumed to increase every year as described in the model section of this report.

The 20 year prediction of oil, gas, and water production from this run of the hyperbolic decline model was used as input data for the series of 26 runs of the economic model. This prediction represents the maximum production which could occur on Federal leases assuming no economic considerations. While the data presented graphically represents summary data for the entire U.S., information is available from the output of the model to plot each of the leases individually. Summary data is also provided for each of the states containing production on federal lands.

7.2.2. Decline Model Predictions Graphical Presentation

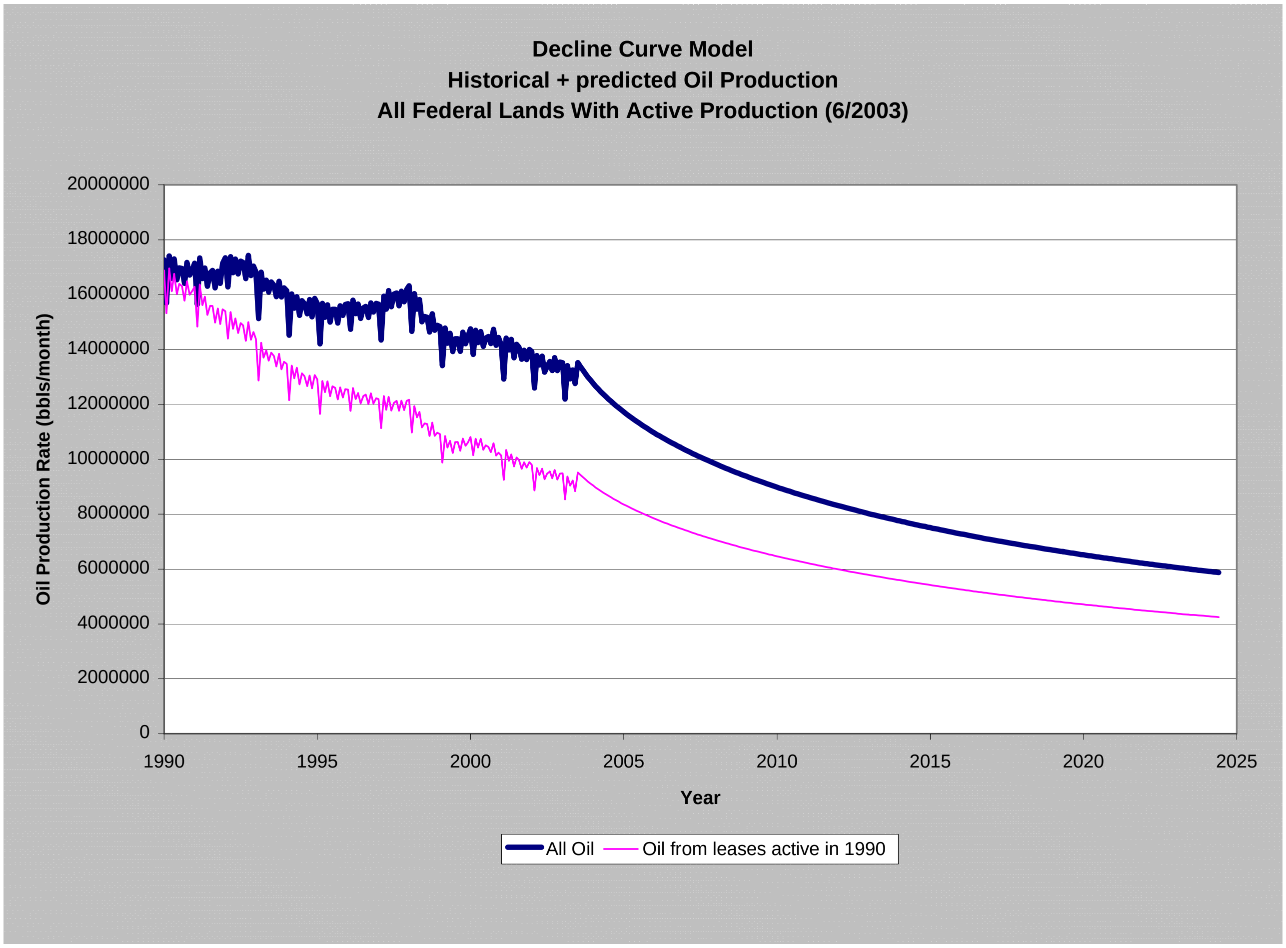

Figure 7-1

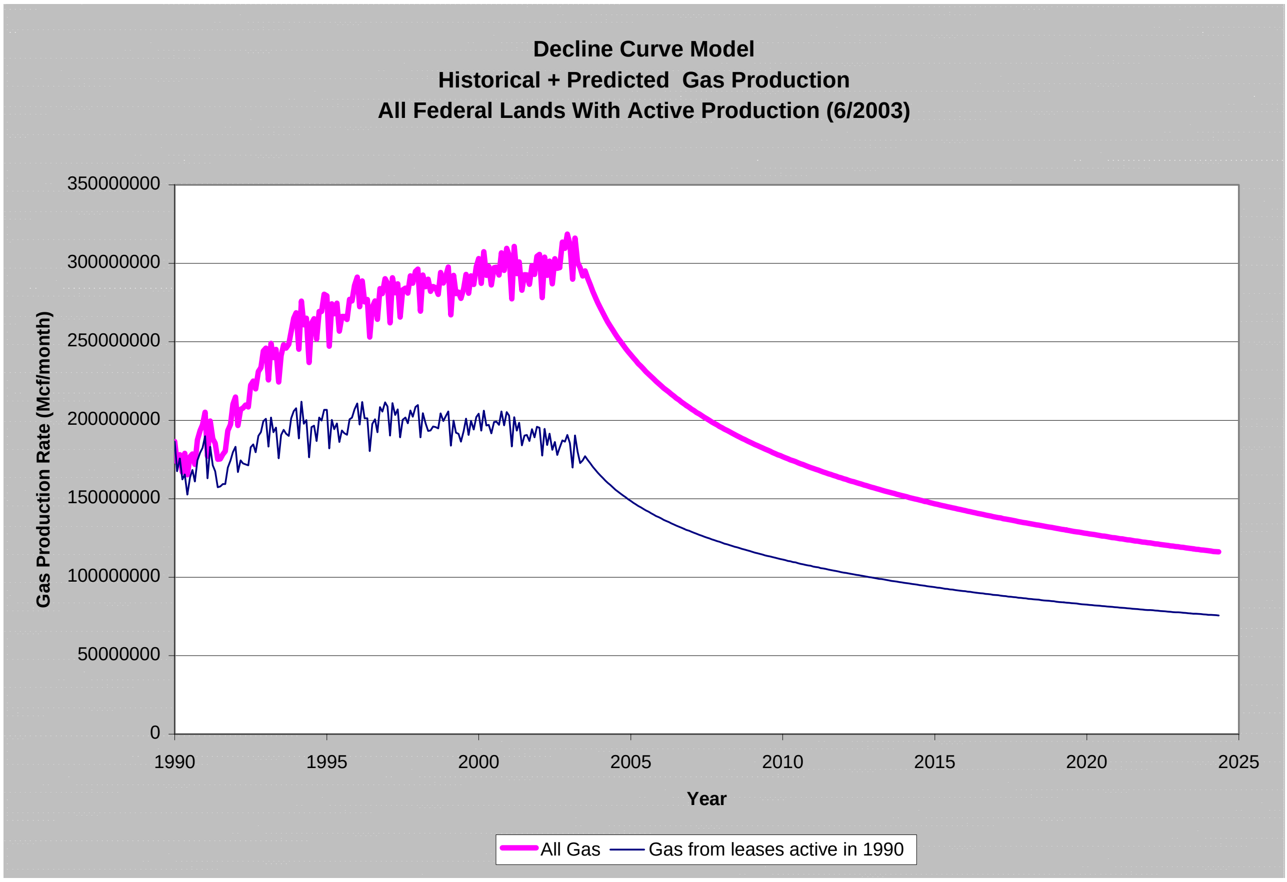
Decline Curve Model
Historical + Predicted Gas Production
All Federal Lands With Active Production (6/2003)
Gas Production Rate (Mcf/month)
350000000
300000000
250000000
200000000
150000000
100000000
50000000
0
1990
1995
2000
2005
2010
2015
2020
2025
Year
All Gas
Gas from leases active in 1990

Figure 7-2

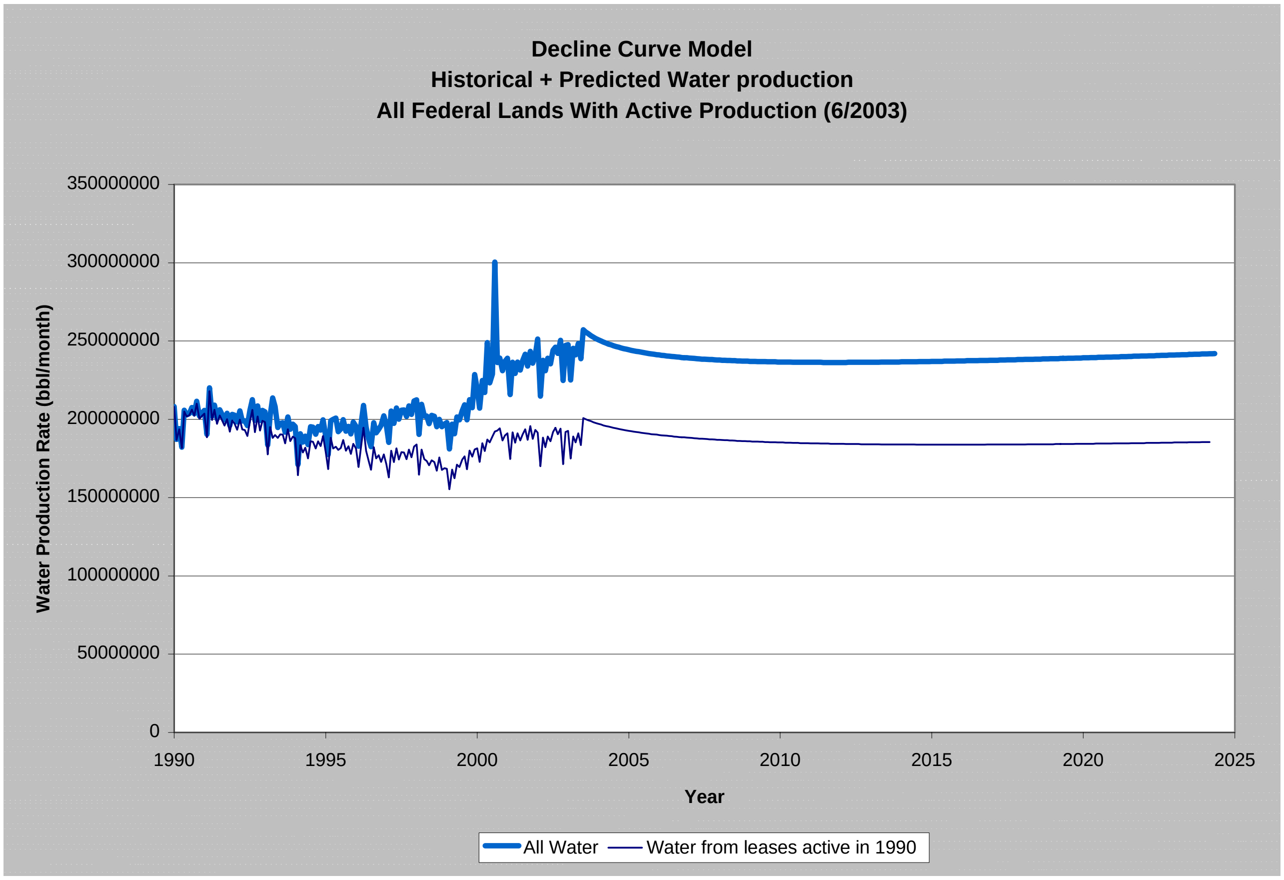
Decline Curve Model
Historical + Predicted Water production
All Federal Lands With Active Production (6/2003)
Water Production Rate (bbl/month)
350000000
300000000
250000000
200000000
150000000
100000000
50000000
0
1990
1995
2000
2005
2010
2015
2020
2025
Year
All Water
Water from leases active in 1990

Figure 7-3

7.3. Economic Model Analysis

7.3.1. Constant 12.5% Scenario

A total of seven constant price economic runs were performed using the constant 12.5% royalty scenario. This means that at any price and any production rate, a royalty of 12.5% is paid by the operator. Half is paid to the Federal treasury and the other half goes to the state. A royalty of 12.5% is also applied to any Indian or private allocation.

Monthly predictions for all onshore Federal lands are presented graphically in Figures 7-4 and 7-5. Figure 7-4 shows monthly historical oil production from 1/1990 to 6/2003 with predictions for all 7 constant price tracks all of the way through 6/2024. Figure 7-5 shows exactly the same thing for historical and predicted gas production.

Table 7-1 provides a breakout of the 20 year totals of predicted production (7/2004 – 6/2024) into Federal, Indian, and private allocations. Table 7-2 provides 20 year totals of royalty and severance tax payments. The royalty payments are broken out into Federal, Indian, and private payments. The severance tax is paid on the operator share of production with proceeds going to the state.

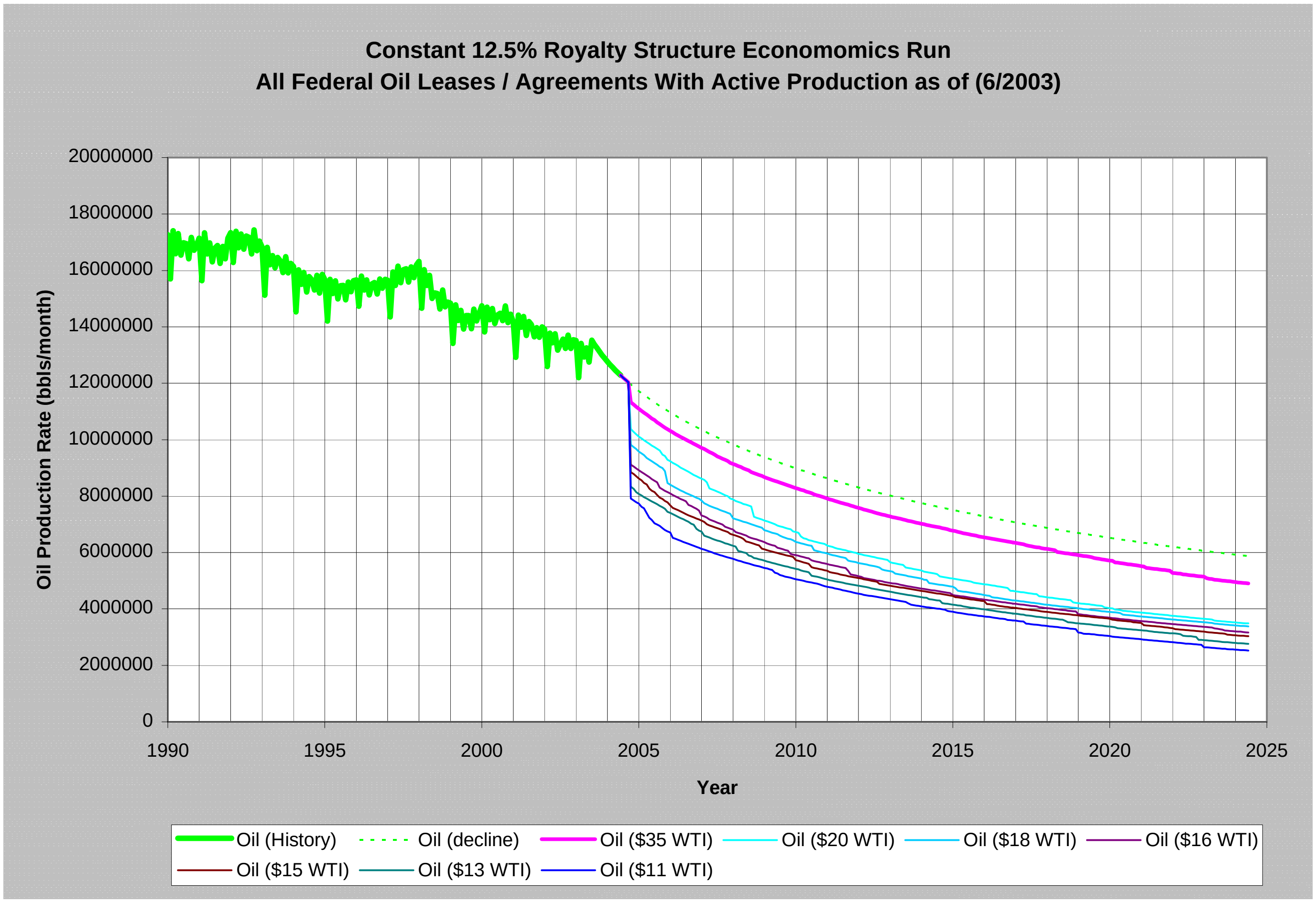

Figure 7-4

Constant 12.5 % Royalty Structure 20 Year Summary of Oil and Gas Production									
		Oil Production				Gas Production			
Oil Price ($/bbl)	Gas Price ($/mcf)	Total (MMbbl)	Federal (MMbbl)	Indian (MMbbl)	Private (MMbbl)	Total (BCF)	Federal (BCF)	Indian (BCF)	Private (BCF)
$35.00	$4.67	1749.5	893.4	99.4	756.7	37287.8	23528.8	3260.2	10498.7
$20.00	$2.67	1389.7	639.5	80.7	669.5	36344.3	22874.6	3178.3	10291.5
$18.00	$2.40	1310.4	590.2	75.3	644.8	36084.0	22706.5	3147.6	10229.8
$16.00	$2.13	1237.7	544.4	71.2	622.1	35727.0	22479.3	3101.3	10146.5
$15.00	$2.00	1200.1	520.9	69.2	610.0	35487.8	22332.0	3072.6	10083.3
$13.00	$1.73	1131.3	482.5	64.0	584.7	34826.8	21914.1	2999.4	9913.3
$11.00	$1.47	1051.5	438.6	58.4	554.5	33763.7	21224.8	2895.6	9643.3

Table 7-1

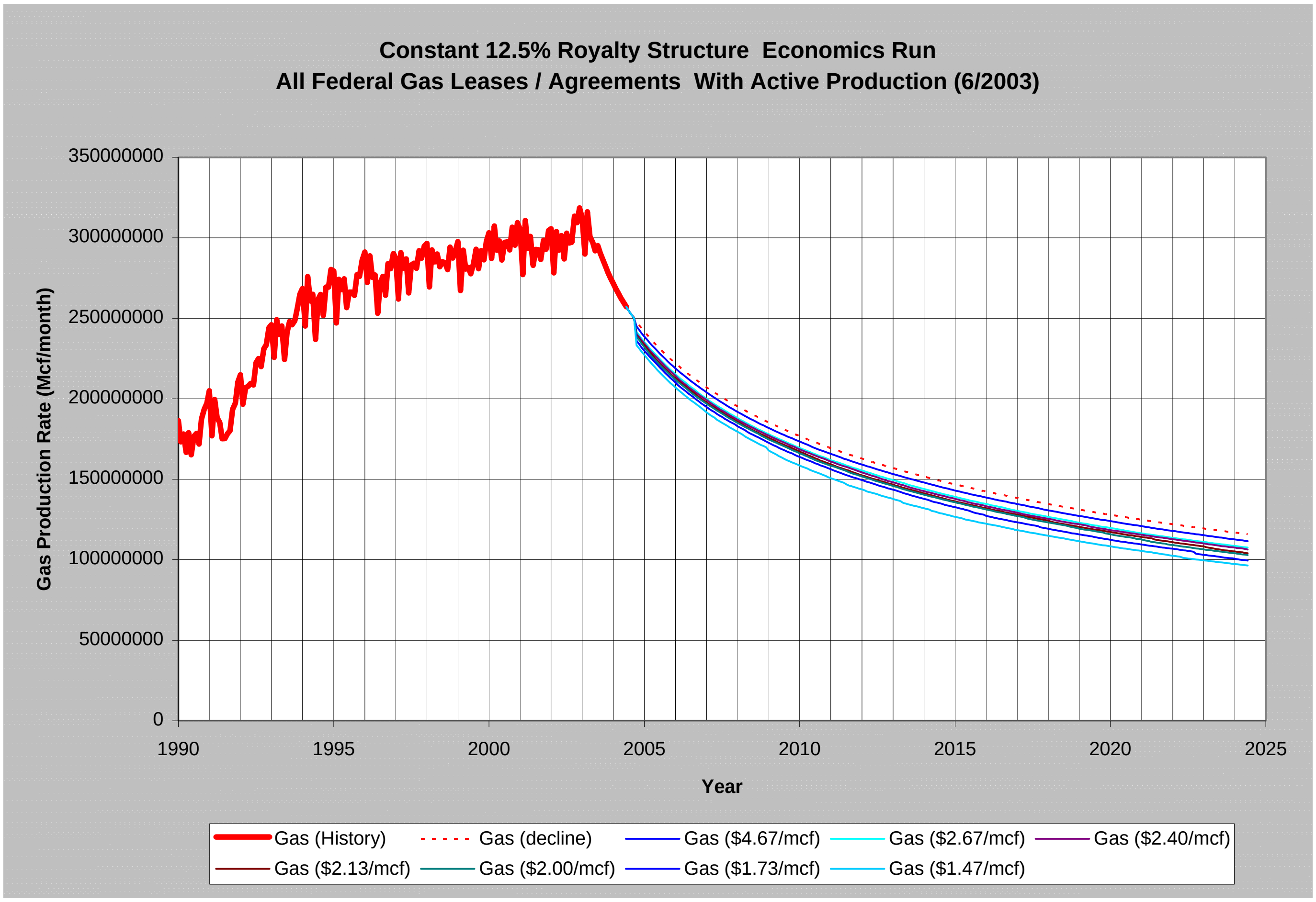

Figure 7-5

Constant 12.5% Royalty Structure 20 Year Summary of Royalty and Severance Payments						
Oil Price ($/bbl)	**Gas Price ($/mcf)**	**Federal Royalty ($ Million)**	**State Royalty ($ Million)**	**Indian Royalty ($ Million)**	**Private Royalty ($ Million)**	**State Severance ($ Million)**
$35.00	$4.67	9114.3	9114.3	2375.8	9721.1	19485.9
$20.00	$2.67	4792.4	4792.4	1281.0	5230.1	10404.3
$18.00	$2.40	4231.0	4231.0	1129.2	4620.0	9199.2
$16.00	$2.13	3681.0	3681.0	979.5	4023.5	8012.5
$15.00	$2.00	3414.6	3414.6	907.4	3731.1	7436.0
$13.00	$1.73	2874.5	2874.5	758.2	3137.2	6259.6
$11.00	$1.47	2342.8	2342.8	614.0	2555.3	5107.0

Table 7-2

7.3.2. Current Royalty Scenario

A total of seven constant price economic runs were performed using the current royalty. This means that at any price and any production rate, a currently active royalty rate provided by Minerals Management Service (MMS) is applied to the Federal allocation of oil production. These rates account for any heavy oil or stripper oil well incentives currently in place on the property. Half is paid to the Federal treasury and the other half goes to the state. A royalty of 12.5% is assumed for any Indian or private allocation of oil production as well as all gas production. Note, there are some gas properties which get 5% royalty. This is accounted for in the scenario.

Monthly predictions for all onshore Federal lands are presented graphically in Figures 7-6 and 7-7. Figure 7-6 shows monthly historical oil production from 1/1990 to 6/2003 with predictions for all 7 constant price tracks through 6/2024. Figure 7-7 shows exactly the same thing for historical and predicted gas production. Notice the difference in Figure 7-6 between the decline curve and the $35 oil prediction. Roughly 4% of total production is immediately shut in because the model says it is not economic at $35 WTI. We know that these leases produce today at $35 WTI oil prices. On close examination, it is found that most of these leases are producing at 1 or 2 bbls/day/well. Obviously there are other factors that are occurring in determining the economic viability of a given lease, since our operating cost equations do not predict favorable economics at such low production rates.

Table 7-3 provides a breakout of the 20 year totals of predicted production (7/2004 – 6/2024) into Federal, Indian, and private allocations. Table 7-4 provides 20 year totals of royalty and severance tax payments. The royalty payments are broken out into Federal, Indian, and private payments. The severance tax is paid on the operator share of production with proceeds going to the state.

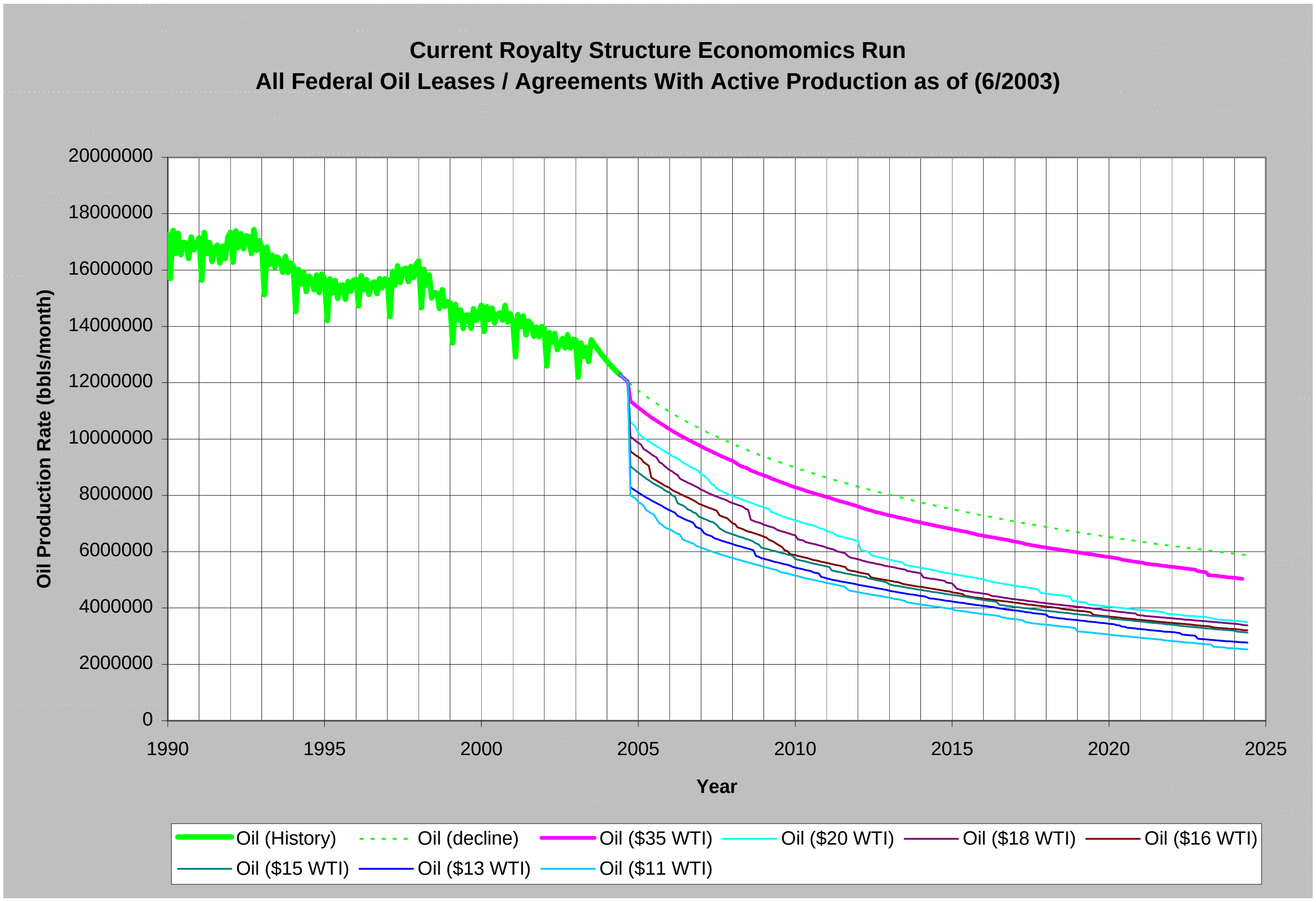

Figure 7-6

Current Royalty Structure 20 Year Summary of Oil and Gas Production									
		Oil Production				Gas Production			
Oil Price ($/bbl)	Gas Price ($/mcf)	Total (MMbbl)	Federal (MMbbl)	Indian (MMbbl)	Private (MMbbl)	Total (BCF)	Federal (BCF)	Indian (BCF)	Private (BCF)
$35.00	$4.67	1761.6	905.4	99.0	757.3	37297.1	23540.3	3257.5	10499.3
$20.00	$2.67	1424.5	673.8	77.7	673.1	36352.7	22885.1	3174.6	10293.0
$18.00	$2.40	1339.6	618.5	73.2	647.9	36091.8	22717.5	3143.1	10231.2
$16.00	$2.13	1254.9	561.2	69.4	624.3	35733.0	22489.8	3096.1	10147.1
$15.00	$2.00	1215.5	536.0	67.5	612.0	35502.2	22351.0	3067.4	10083.9
$13.00	$1.73	1140.7	491.3	63.4	586.0	34841.5	21932.7	2994.3	9914.5
$11.00	$1.47	1060.8	447.0	57.9	555.9	33782.9	21247.3	2890.9	9644.8

Table 7-3

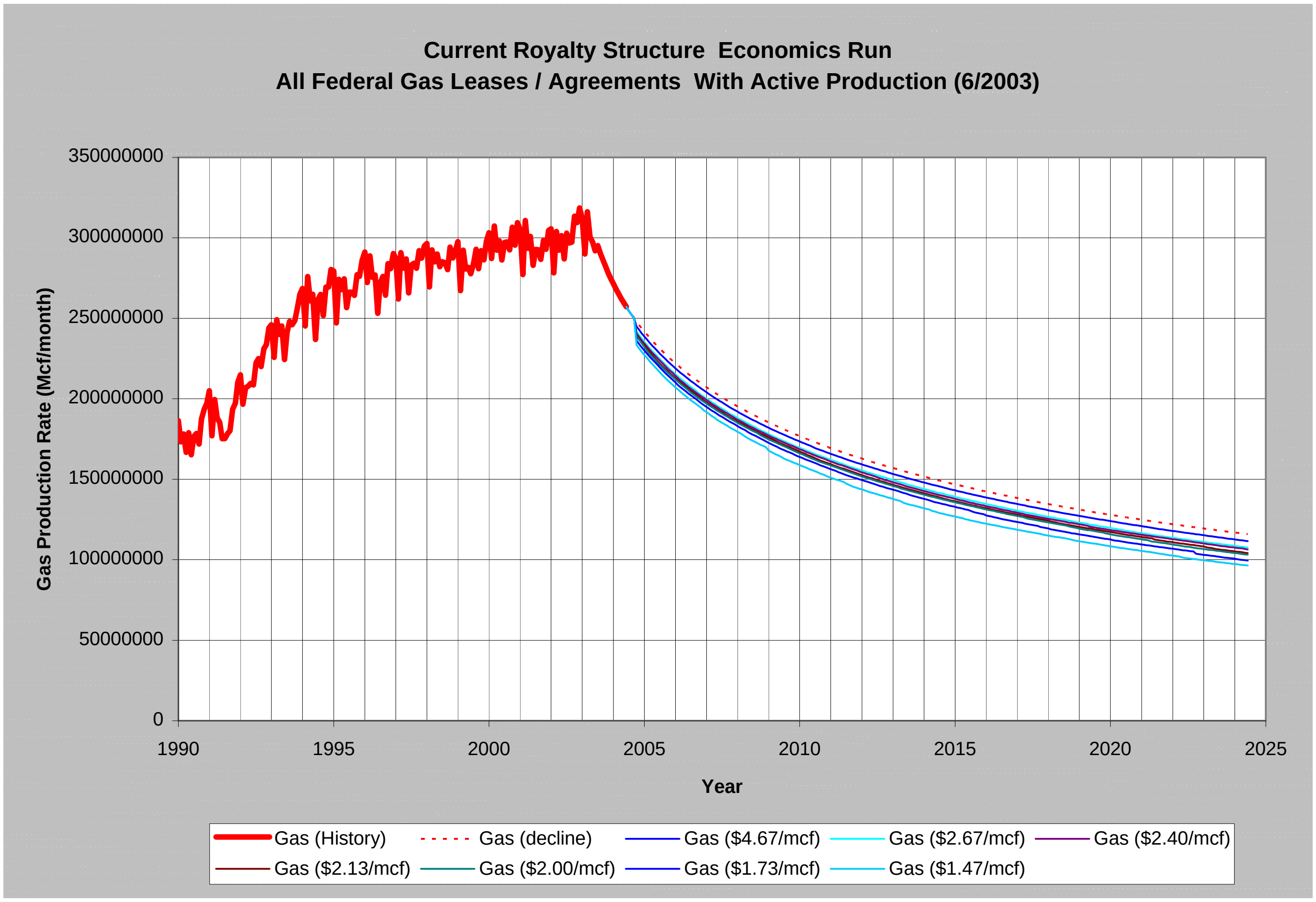

Figure 7-7

Current Royalty Structure 20 Year Summary of Royalty and Severance Payments						
Oil Price ($/bbl)	**Gas Price ($/mcf)**	**Federal Royalty ($ Million)**	**State Royalty ($ Million)**	**Indian Royalty ($ Million)**	**Private Royalty ($ Million)**	**State Severance ($ Million)**
$35.00	$4.67	8539.6	8539.6	2652.1	9723.5	19568.9
$20.00	$2.67	4595.8	4595.8	1414.2	5239.0	10456.2
$18.00	$2.40	4073.9	4073.9	1246.1	4627.0	9240.4
$16.00	$2.13	3553.3	3553.3	1080.0	4027.9	8040.6
$15.00	$2.00	3303.6	3303.6	1000.0	3734.9	7464.2
$13.00	$1.73	2788.2	2788.2	837.0	3139.5	6281.4
$11.00	$1.47	2280.3	2280.3	678.9	2557.4	5124.2

Table 7-4

7.3.3. Proposed “Energy Bill” Incentive Scenario

A total of six constant price economic runs were performed using the “energy bill” royalty scenario. The “energy bill” royalty scenario specifies a price trigger as well as a production rate trigger. Assume that for all six price tracks presented in this analysis, the price is considered to be below the trigger price for both oil and gas. The production trigger is always modeled as being less than 15 BOE/day. Basically, the lease production can qualify for a reduced 5% royalty rate by meeting both a qualifying production rate and qualifying product price. Oil and gas production qualify separately for the royalty relief. Both rate and product price qualifications must be met for four consecutive months in order to qualify the lease for a reduced royalty rate. Once qualified for 5% royalty rate, if price and rate qualifications are not met for four consecutive months, the royalty reverts back to 12.5% and the property must re-qualify for relief. The rate used to qualify the production is determined each month by dividing the total monthly BOE for the lease by the monthly production days on line. The reduced rate applies to the Federal allocation of production. Half of this royalty is paid to the Federal treasury and the other half goes to the state. A royalty of 12.5% is applied to any Indian or private allocation at all times for this analysis.

Monthly predictions for all onshore Federal lands are presented graphically in Figures 7-8 and 7-9. Figure 7-8 shows monthly historical oil production from 1/1990 to 6/2003 with predictions for all 6 constant price tracks all of the way through 6/2024. Figure 7-9 shows exactly the same thing for historical and predicted gas production.

Table 7-5 provides a breakout of the 20 year totals of predicted production (7/2004 – 6/2024) into Federal, Indian, and private allocations. Table 7-6 provides 20 year totals of royalty and severance tax payments. The royalty payments are broken out into Federal, Indian, and private payments. The severance tax is paid on the operator share of production with proceeds going to the state.

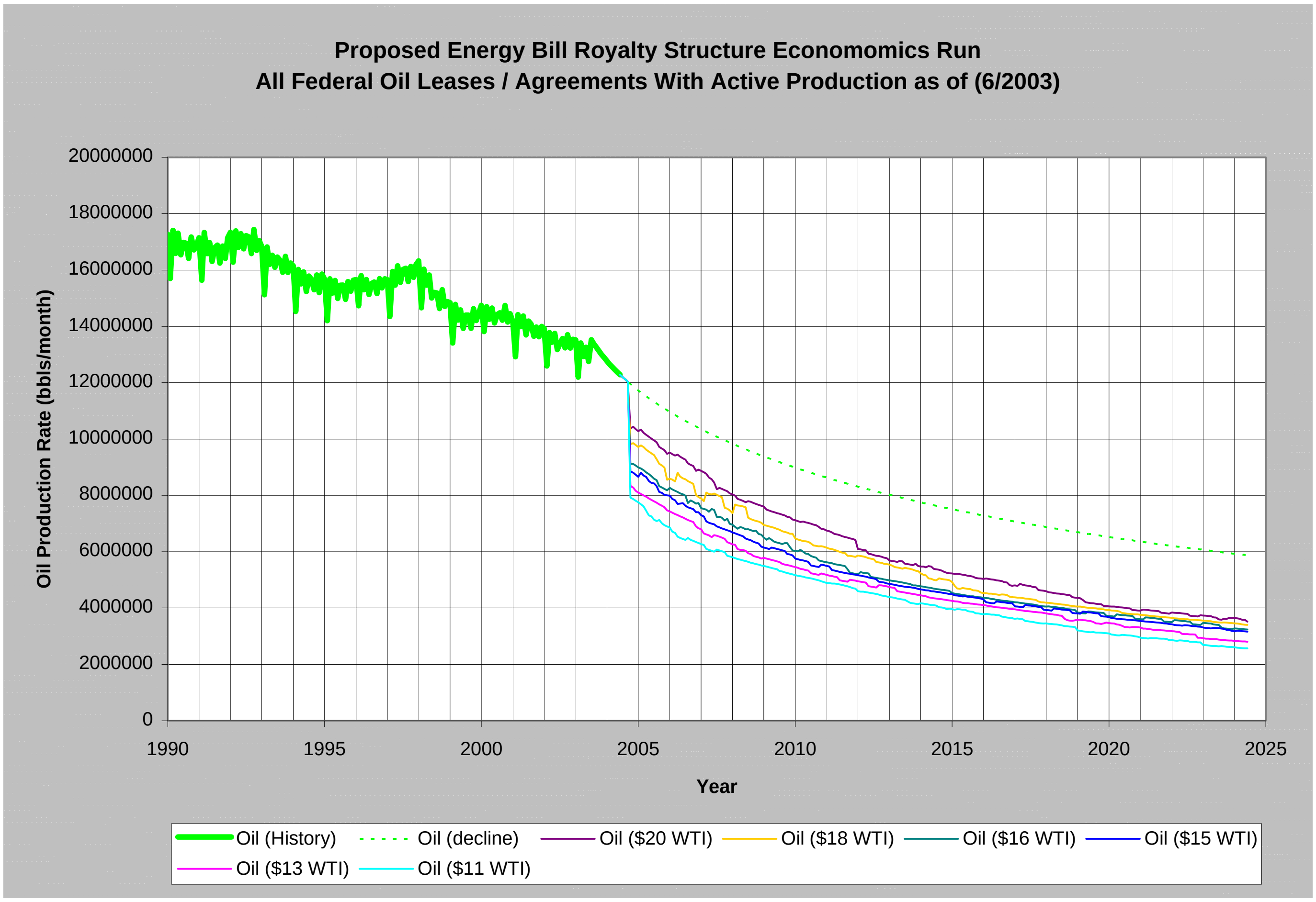

Figure 7-8

Energy Bill Royalty Structure
20 Year Summary of Oil and Gas Production

		Oil Production				Gas Production			
Oil Price ($/bbl)	**Gas Price ($/mcf)**	**Total (MMbbl)**	**Federal (MMbbl)**	**Indian (MMbbl)**	**Private (MMbbl)**	**Total (BCF)**	**Federal (BCF)**	**Indian (BCF)**	**Private (BCF)**
$20.00	$2.67	1434.4	680.2	80.7	673.5	36477.0	22994.5	3178.3	10304.3
$18.00	$2.40	1341.1	618.5	75.3	647.3	36221.5	22832.2	3147.6	10241.7
$16.00	$2.13	1258.4	563.3	71.2	623.9	35893.0	22632.2	3101.3	10159.6
$15.00	$2.00	1220.9	540.0	69.2	611.7	35682.1	22509.0	3072.6	10100.5
$13.00	$1.73	1147.1	497.5	64.0	585.7	35081.3	22143.5	2999.4	9938.5
$11.00	$1.47	1067.2	453.4	58.4	555.4	34107.7	21526.7	2895.6	9685.4

Table 7-5

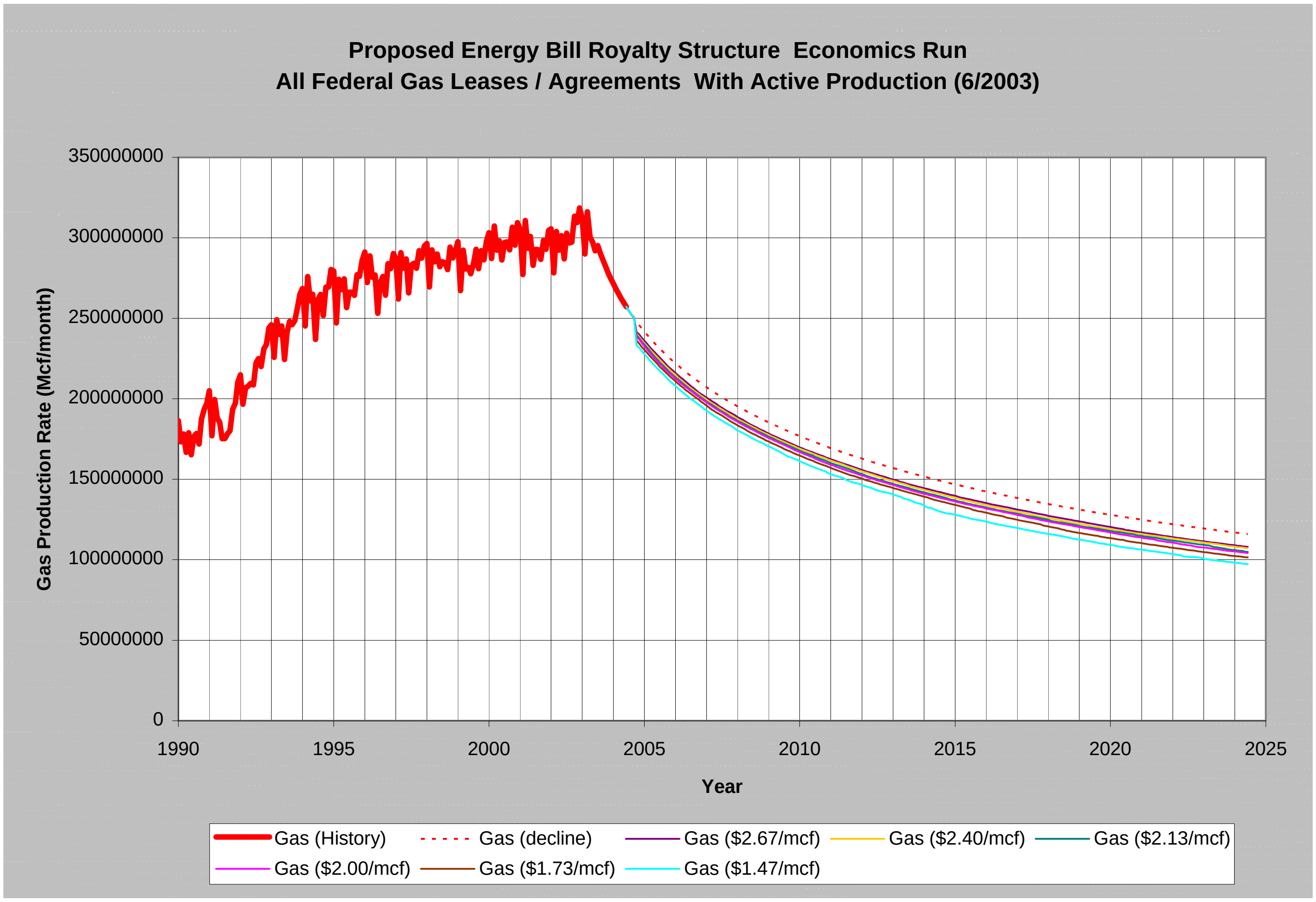

Figure 7-9

Energy Bill Royalty Structure 20 Year Summary of Royalty and Severance Payments						
Oil Price ($/bbl)	Gas Price ($/mcf)	Federal Royalty ($ Million)	State Royalty ($ Million)	Indian Royalty ($ Million)	Private Royalty ($ Million)	State Severance ($ Million)
$20.00	$2.67	4283.6	4283.6	1281.0	5244.3	10576.1
$18.00	$2.40	3797.0	3797.0	1129.2	4629.2	9339.6
$16.00	$2.13	3318.4	3318.4	979.5	4030.7	8134.6
$15.00	$2.00	3090.7	3090.7	907.4	3738.8	7554.5
$13.00	$1.73	2629.3	2629.3	758.2	3144.4	6362.8
$11.00	$1.47	2179.8	2179.8	614.0	2564.5	5197.6

Table 7-6

7.3.4. Proposed "Energy Bill" With Injection Wells Incentive Scenario

Six constant price economic runs were performed using the "energy bill" with injection wells royalty scenario. Everything said about the "energy bill" royalty scenario discussed in section 7.3.3 applies to this scenario with the exception of the way in which the qualifying production rate is calculated. In this scenario the rate used to qualify the production is determined each month by dividing the total monthly lease BOE by the sum of monthly production <u>and</u> monthly injection days on line. This more liberal form of production accounting allows waterflood and steamflood operators to count their injection wells when calculating per day per well production. Once again a royalty of 12.5% is applied to any Indian or private allocation at all times for this analysis.

Monthly predictions for all onshore Federal lands are presented graphically in Figures 7-10 and 7-11. Figure 7-10 shows monthly historical oil production from 1/1990 to 6/2003 with predictions for all 6 constant price tracks all of the way through 6/2024. Figure 7-11 shows exactly the same thing for historical and predicted gas production.

Table 7-7 provides a breakout of the 20 years totals of predicted production (7/2004 – 6/2024) into Federal, Indian, and private allocations. Table 7-8 provides 20 year totals of royalty and severance tax payments. The royalty payments are broken out into Federal, Indian, and private payments. The severance tax is paid on the operator share of production with proceeds going to the state.

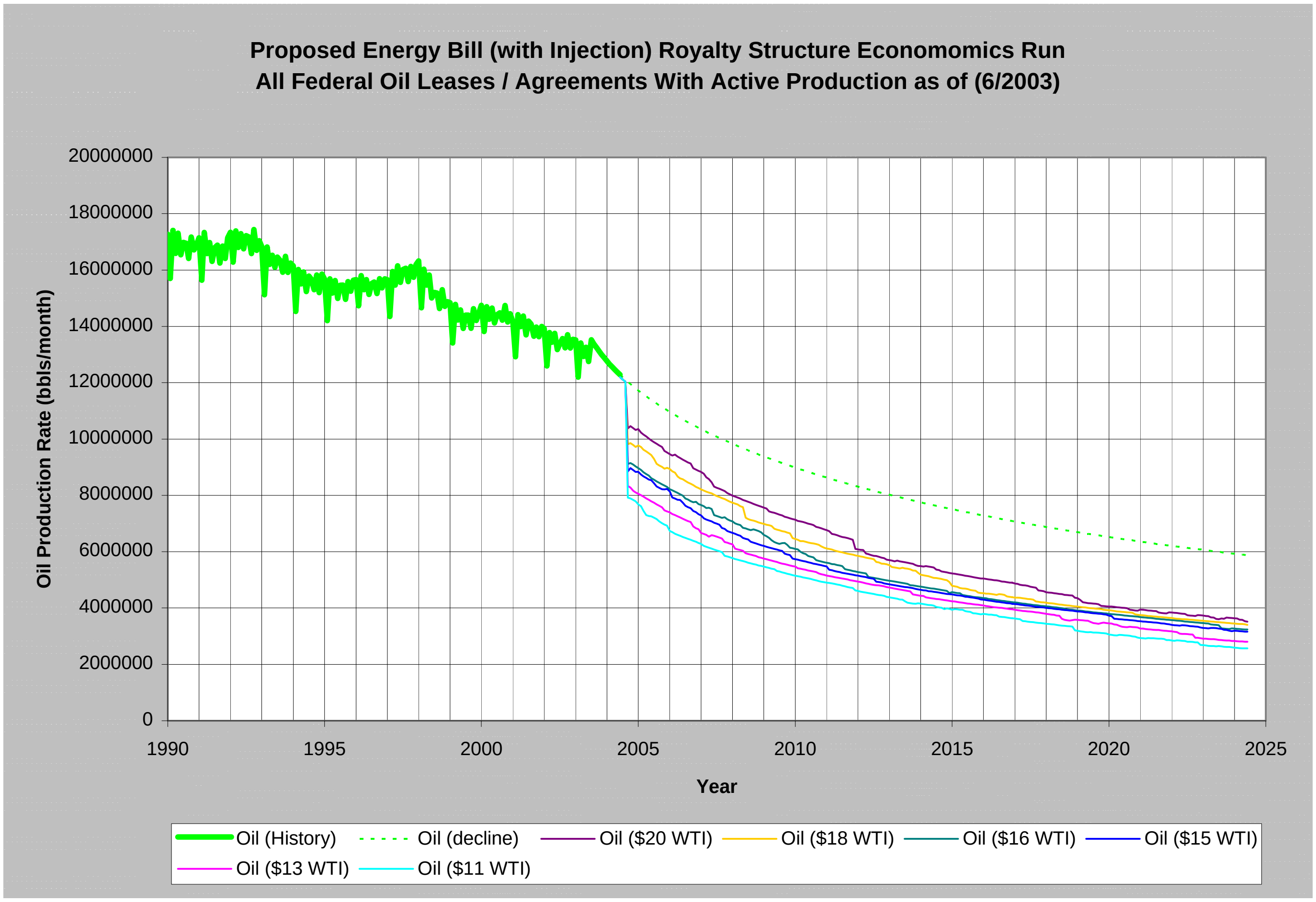

Figure 7-10

Energy Bill (with Injection) Royalty Structure with injection 20 Year Summary of Oil and Gas Production									
		Oil Production				Gas Production			
Oil Price ($/bbl)	Gas Price ($/mcf)	Total (MMbbl)	Federal (MMbbl)	Indian (MMbbl)	Private (MMbbl)	Total (BCF)	Federal (BCF)	Indian (BCF)	Private (BCF)
$20.00	$2.67	1438.4	683.0	80.7	674.7	36479.0	22995.8	3178.3	10304.9
$18.00	$2.40	1349.0	624.8	75.3	648.9	36223.4	22833.2	3147.6	10242.6
$16.00	$2.13	1265.6	569.1	71.2	625.3	35896.3	22635.0	3101.3	10160.1
$15.00	$2.00	1228.2	546.4	69.2	612.7	35685.2	22511.8	3072.6	10100.9
$13.00	$1.73	1150.0	500.2	64.0	585.8	35083.1	22145.1	2999.4	9938.6
$11.00	$1.47	1069.7	455.6	58.4	555.7	34110.5	21529.3	2895.6	9685.6

Table 7-7

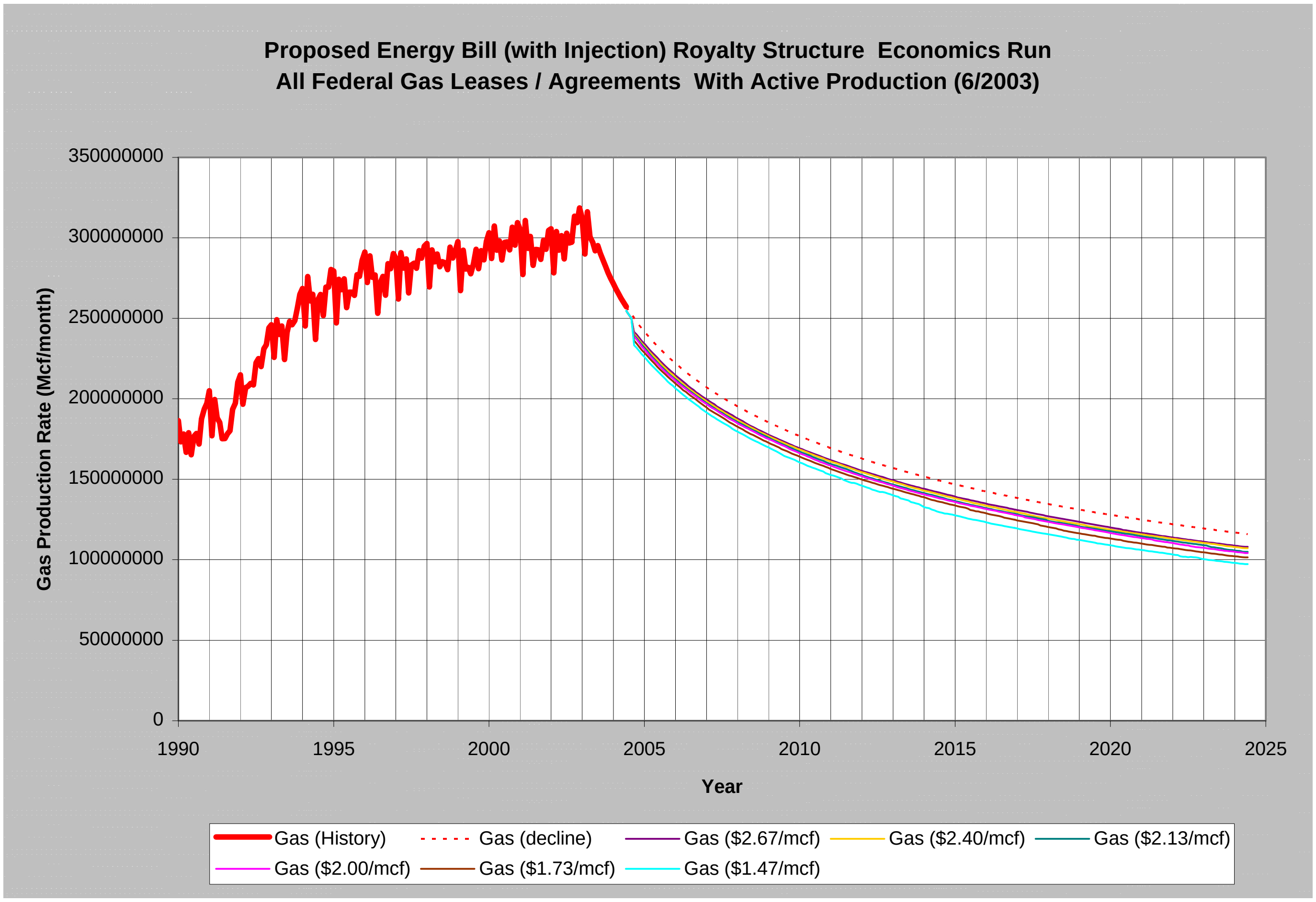

Figure 7-11

Energy Bill (with Injection) Royalty Structure
20 Year Summary of Royalty and Severance Payments

Oil Price ($/bbl)	Gas Price ($/mcf)	Federal Royalty ($ Million)	State Royalty ($ Million)	Indian Royalty ($ Million)	Private Royalty ($ Million)	State Severance ($ Million)
$20.00	$2.67	4222.0	4222.0	1281.0	5247.3	10594.0
$18.00	$2.40	3753.0	3753.0	1129.2	4633.1	9354.9
$16.00	$2.13	3291.8	3291.8	979.5	4033.6	8147.5
$15.00	$2.00	3071.8	3071.8	907.4	3740.7	7565.1
$13.00	$1.73	2617.9	2617.9	758.2	3144.7	6367.9
$11.00	$1.47	2175.3	2175.3	614.0	2564.8	5200.8

Table 7-8

7.3.5. Incremental Comparison of Summary Results

There is an implicit assumption when assessing the effect of a royalty relief proposal that there will be a benefit defined by an increase in production. There is also a cost which can be defined as a loss in public sector revenue due to the fact that a smaller percentage of production going to royalty payments. The hope is that there is a scenario where the outcome may be described as “revenue positive”, meaning that so much incremental production is stimulated by the incentive that the amount of royalty collected is actually greater than it would have been without the incentive even though the amount collected per barrel produced is less.

The goal of this analysis is to compare the effects of three royalty structures at a range of product prices. The three royalty scenarios are the energy bill, energy bill with injection wells, and the current royalty structure in place today. In order to compare the cost/benefit ratios of these incentives in a consistent manner, the 20 year summary results which are found in Tables 7-3 through 7-8 are compared to the results of the constant 12.5% royalty case found in Tables 7-1 and 7-2. The incremental results from these comparisons are then presented in Table 7-9.

Table 7-9 presents incremental results for the three royalty relief scenarios analyzed at seven different constant price tracks. The following incremental data is presented in the table to allow for comparison. Incremental production is presented in the form of incremental oil, incremental gas, and incremental BOE. In all of the scenarios generated in this study there was always a positive production increment with reduced royalty.

Cost of the incentive is calculated by incremental Federal royalty collected, and incremental state revenue collected. State revenue collected is calculated by adding the state royalty collected to the state severance tax collected from the operator. Some of the revenue lost by the state in providing royalty relief is offset by increased severance tax collection. The cost to both the Federal and state treasury is then provided in a cost per incremental BOE added. This is calculated by dividing both the incremental federal royalty and the incremental state revenue by the incremental BOE generated. Finally, the Federal cost and state cost are combined together to get the total cost per incremental BOE produced. All of the scenarios generated in this study turned out to be “revenue negative” meaning that there was less revenue generated for the Federal and state treasury than there would be under a standard 12.5% royalty. There is always going to be a cost associated with producing incremental oil by the safety net royalty relief programs being considered. The next section provides conclusions generated by comparison of the results presented in Table 7-9 for the three royalty relief scenarios.

20 Year Incremental Comparison to Constant 12.5% Royalty Case

Current Royalty Structure

Oil Price ($/bbl)	Gas Price ($/mcf)	Inc. Oil (MMBBL)	Inc. Gas (BCF)	Inc. BOE (MMBOE)	Fed Roy ($ MM)	State Rev ($ MM)	Fed Cost ($/BOE)	State Cost ($/BOE)	Total Cost ($/BOE)
$35.00	$4.67	12.1	9.3	13.7	-574.8	-491.8	42.09	36.01	78.10
$20.00	$2.67	34.8	8.3	36.2	-196.6	-144.8	5.43	4.00	9.42
$18.00	$2.40	29.2	7.8	30.5	-157.1	-115.9	5.15	3.80	8.95
$16.00	$2.13	17.3	6.0	18.3	-127.7	-99.6	6.99	5.45	12.44
$15.00	$2.00	15.4	14.4	17.8	-111.1	-82.9	6.22	4.65	10.87
$13.00	$1.73	9.4	14.7	11.9	-86.3	-64.5	7.28	5.44	12.72
$11.00	$1.47	9.3	19.2	12.5	-62.5	-45.3	5.01	3.63	8.63

Energy Bill Royalty Structure

Oil Price ($/bbl)	Gas Price ($/mcf)	Inc. Oil (MMBBL)	Inc. Gas (BCF)	Inc. BOE (MMBOE)	Fed Roy ($ MM)	State Rev ($ MM)	Fed Cost ($/BOE)	State Cost ($/BOE)	Total Cost ($/BOE)
$35.00	$4.67	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00
$20.00	$2.67	44.7	132.7	66.8	-508.8	-337.0	7.61	5.04	12.66
$18.00	$2.40	30.7	137.5	53.6	-434.0	-293.6	8.09	5.48	13.57
$16.00	$2.13	20.7	166.0	48.4	-362.6	-240.5	7.50	4.97	12.47
$15.00	$2.00	20.8	194.3	53.2	-323.9	-205.4	6.09	3.86	9.96
$13.00	$1.73	15.9	254.6	58.3	-245.2	-142.0	4.21	2.44	6.64
$11.00	$1.47	15.7	344.0	73.0	-163.0	-72.4	2.23	0.99	3.22

Energy Bill Royalty Structure with injection

Oil Price ($/bbl)	Gas Price ($/mcf)	Inc. Oil (MMBBL)	Inc. Gas (BCF)	Inc. BOE (MMBOE)	Fed Roy ($ MM)	State Rev ($ MM)	Fed Cost ($/BOE)	State Cost ($/BOE)	Total Cost ($/BOE)
$35.00	$4.67	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.00
$20.00	$2.67	48.7	134.6	71.1	-570.4	-380.8	8.02	5.36	13.38
$18.00	$2.40	38.6	139.4	61.9	-478.0	-322.3	7.73	5.21	12.94
$16.00	$2.13	27.9	169.4	56.1	-389.2	-254.3	6.94	4.53	11.47
$15.00	$2.00	28.1	197.4	61.0	-342.8	-213.8	5.62	3.50	9.12
$13.00	$1.73	18.7	256.3	61.4	-256.5	-148.2	4.18	2.41	6.59
$11.00	$1.47	18.1	346.8	75.9	-167.5	-73.8	2.21	0.97	3.18

Table 7-9

7.4. Conclusions and Recommendations

After careful interpretation of the safety net royalty relief model results, a list of six conclusions was created which capture the major points gleaned from this analysis.

1. **Existing royalty relief programs are not cost effective at current prices –** This rather obvious statement is illustrated by looking at the incremental results for the current royalty case at $35 WTI oil price and $4.67 Henry Hub gas price. These prices are fairly representative of oil and gas prices as of August 2004. The results predict that over a twenty year period over a billion dollars of public sector revenue would be lost with only and additional 13.7 million BOE produced. Total cost would be about $78 for each additional BOE produced. This is one reason plans are underway to create new incentive packages for Federal lands production.

2. **Proposed safety net royalty relief proposals will not be revenue generators, at least not under flat price scenarios –** It may be clearly seen looking at table 6-9 that there is no royalty scenario at any price which generates more revenue than the constant 12.5% royalty case. All of these royalty relief proposals will lose money as far as the Federal and state treasuries are concerned under flat price track scenarios. The cost may be justified, however, in that producers may be kept operating through times of low prices insuring that resource and infrastructure is still available when prices rise once again. Certainly there are possible price tracks where these proposals may be shown to be revenue positive.

3. **Incremental production due to safety net royalty relief scenarios is relatively insignificant -** One thing that is very clear is that the relative amount of production generated by royalty relief programs, either the current programs or the proposed safety net programs, is very small. The largest increase in total production relative to the 12.5% royalty case occurs in the energy bill with injection wells case at $11/bbl WTI and $1.47/mcf Henry Hub. The increase in BOE due to the incentive is at most 1.1%. The largest increase in oil production occurs at the high price of $20/bbl WTI and it is only 3.5%. The largest gas increase occurs at the low price of $1.47/mcf and only amounts to about 1%. Incentive programs designed to significantly increase oil and gas production will have to consider exploration and development of new fields or application of new technologies on these old fields possibly with incentives to apply the new technologies.

4. **Gas production is not nearly as sensitive as oil production to lower prices in the ranges considered for this study –** Due to lower operating costs for gas wells as opposed to oil, gas production has shown to be much less sensitive to differences in price. For instance, in the constant 12.5% royalty case, 20 year oil production at $11/bbl is only 60% of what it is at $35/bbl. Looking at the corresponding results for gas, at $1.47/mcf production is over 90% of that produced at $4.67/mcf.

5. **Cost effective to include injection days on line when evaluating property for incentive –** This analysis predicts that allowing operators of steamflood and waterflood properties to include injection days on line when qualifying for the energy bill incentive package is effective at generating additional incremental oil at all prices considered. This increase in incremental oil production is on the order of 20%. This method of qualifying projects may be considered cost effective in that the total cost per barrel of incremental oil added is reduced in all cases over the corresponding energy bill case. On the other hand, since none of the incentives are revenue positive, there is an increase in cost to the Treasury and to the states for allowing injection days online into the rate qualification.

6. **Proposed energy bill incentives are more cost effective at the lower prices considered, at higher prices they become more expensive than the current royalty structure -** At oil prices of $15 and below, the total cost per incremental BOE in the energy bill scenario is less than the cost of incremental BOE generated by the current royalty structure. Figure 7-12 below presents these results in graphical fashion.

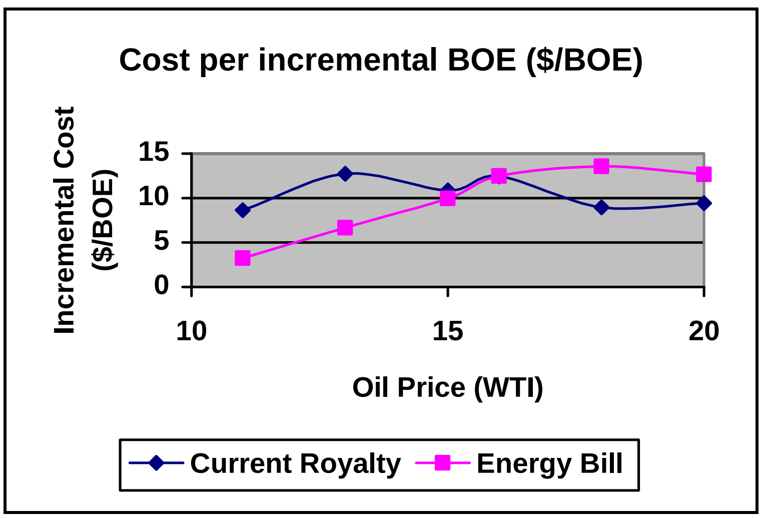

Figure 7-12

At prices above $15 the current structure is more cost effective even though the energy bill scenario produces more BOE. The reason for this is that the energy bill scenarios give royalty relief to gas production whereas the current structure does not. Upon examination of the results of the energy bill runs, it is observed that the incentives are most effective for oil at higher prices and are more effective for gas as the prices become lower. This is illustrated by looking at Figure 7-13 which shows the relative proportions of incremental oil and gas generated by the energy bill proposal at the various price tracks.

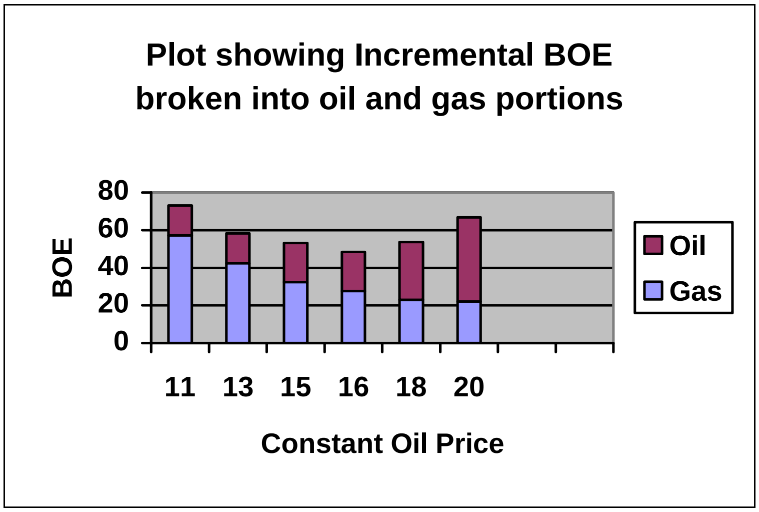

Figure 7-13

At prices above $15 WTI ($2.00/mcf), the energy bill incentive is giving a lot of royalty relief to gas production which does not need the incentive. This is negating the benefit we see from all of the incremental oil that is being produced at the higher prices under the energy bill scenario. At very low prices oil production becomes insensitive to the incentive because at these low prices the incentive is not enough to help extend the life of the oil leases. This highlights that there is probably a mismatch in the trigger prices for oil and gas.

Based on these conclusions derived from this study, the following recommendations are made concerning safety net royalty incentives on Federal lands.

1. **<u>Do not offer royalty relief at high product prices –</u>** Current royalty relief incentives do have maximum price control measures built in, however, these price controls had been adjusted upward for inflation to the point where the incentives are still operating at today's high oil prices. This results in huge losses to Federal and state treasuries. As soon as the price controls finally kick in, the current incentives should be removed and replaced with new language. Clearly, if the proposed energy bill incentive is to replace the current incentive packages it must have carefully considered oil and gas "trigger" prices at which the incentive will take effect.

2. **<u>Consider inclusion of injection wells –</u>** Results of this analysis show that allowing injection days on line to be counted in determining daily rate for qualification purposes does appear to be cost effective in creating incremental oil production at a cost per barrel which is less than the cost of incremental oil produced by restricting rate calculations to only producing days online. The results, however, did not point to a very large difference. Further examination of the waterflood leases likely to benefit from this option should be considered. Addition of injection days on line would be a very controversial addition to the incentive as it may be possible to game the system by injecting small quantities of fluid into a large number of wells to get a reduced royalty rate. The addition of injection days on line is potentially beneficial and should be studied further.

3. **<u>Consider more effective trigger prices for product qualification –</u>** Based on this work, a recommendation would be to examine different combinations of product "trigger" prices for oil and gas. The trigger prices considered in this study all had the same oil/gas price ratio of 7.5. What might make more sense is to consider different combinations such as $20 WTI for oil and $1.50 Henry Hub for gas. In that way oil could benefit from incentives at higher prices where it is still possible to save production with royalty relief. The effective cost would be much reduced since there would be no reason to also give incentives to gas production which would not be as close to the economic limit.

APPENDIX

Summary of Significant Events

- **July 7 & 8 2002 Meeting in Tulsa to review BLM Analytical needs and Modeling Capabilities**
- **October 2002 – MMS Provides Initial Data**
- **February 24, 2003 - Conference Call to define Incentives and Data Availability.**
- **March 5, 2003 - Incentive Definitions Drafted and Circulated for Review**
- **August 7, 2003 – DOE provides Cost Est. for Incentives Work**
- **September 2003 - MMS Provides Updated Provisions Data**
- **September 30, 2003 – Phase One Run Parameters distributed. Phase One Funded**
- **November 13 & 14, 2003 Meeting in Tulsa to review Initial Results. New Incentives (inc. Energy Bill) defined.**
- **January 16, 2004 – Conference Call to Discuss Price Thresholds**
- **February 2004 – BLM provides Well Depth Data Set**
- **February 26, 2004 Conference Call. Review H.O. Properties. Also defined Injection Runs**
- **April 2004 - State of WY provided Ave. State Tax Rates**
- **March 5, 2004 - Conference Call, Discussed Costing and Evaluation of H.O. Production**
- **March 24, 2004 – Conference Call, Reviewed Data Processing & Run Definitions**
- **April 14, 2004 – Conference Call Reviewed Initial Results, Issues of Decline for H.O. and CBM discussed**
- **April 2004 – MMS provided data through 2004**
- **May 12 & 13 - Meeting at MMS at Denver Federal Center.**
- **June 2004 - Additional Royalty information provided by MMS**
- **July 2004 - Final Runs Provided to BLM**
- **September 2004 – Final Report Issued**