# RURAL ECONOMY

**A Net Present Value Model of Natural Gas Exploitation in Northern Alberta: An Analysis of Land Values in Woodland Caribou Ranges**

Grant Hauer
Wiktor Adamowicz
Robert Jagodinski

Project Report # 10-01

# Project Report

**Department of Rural Economy**
Faculty of Agricultural, Life &
Environmental Sciences
University of Alberta
Edmonton, Canada

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The authors are, respectively, Adjunct Professor and Research Associate, Professor and Research Assistant.

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*Abstract*

This report was prepared for the purpose of providing background documentation of inputs to be used in mathematical programming models and papers, which are being prepared for our research project: Ecological and economic tradeoff analysis of conservation strategies for woodland caribou. The report presents a simple net present value model of resource and land value for natural gas in northern Alberta. The variables in the model include costs (drilling, seismic, operating and capital); geological variables (stratigraphic intervals, booked reserves, future reserves); drilling variables (well densities, drilling success rates, and drilling depths); production data and prices. Each variable is described in detail and methods of derivation are provided. A map of net present values for natural gas at a spatial resolution of 250ha sections is provided and overlaid on top of caribou ranges to provide a spatial representation of where the most valuable reserves are in relation to caribou ranges.

JEL Classification: Q49, Q32, Q57
Keywords: Net present value, energy reserves, natural gas, caribou.

**A Net Present Value Model of Natural Gas Exploitation in Northern Alberta: An Analysis of Land Values in Woodland Caribou Ranges**

## 1. Introduction

This paper is one of a series of background documents prepared for the "Ecological and economic tradeoff analysis of conservation strategies for Woodland Caribou Project." The goal of the project is to explore tradeoffs of economic activities, arising from conventional oil and gas exploration and development, oilsands development, and forestry activities, with the protection and recovery of woodland caribou in northern Alberta. Tradeoffs will be presented in terms of a production possibilities frontier or as cost curves that show the opportunity costs of preserving various levels of woodland caribou habitat and population. This paper documents how opportunity costs, expressed in term of land values on a land section level (a land section is ~250 ha, 1/36 of a 10x10 km township), were developed for the natural gas sector. Two other papers under preparation document how land values were developed for conventional oil sector and the oilsands sector. Land values for both of these other sectors were developed in a similar way as for natural gas, but with enough differences to justify separate treatment.

In addition, this paper provides a very crude estimate of total opportunity cost by caribou range, which was achieved by overlaying the land values derived from natural gas exploitation and exploration, with caribou range boundaries. Cost curves for caribou habitat preservation as well as other economic analysis of caribou preservation are reserved for a summary report titled: **Ecological and economic tradeoff analysis of conservation strategies for Woodland Caribou.**

The study area for this project is shown in Figure 1. The caribou herd boundaries were obtained from the Alberta Caribou Committee (ACC). Industrial activity in both the forest and oil/gas sectors is modelled over the entire region, both inside and outside the herd ranges. The first step required to assess tradeoffs of caribou conservation and industrial activity is to quantify the resource values inside and outside each herd boundary.

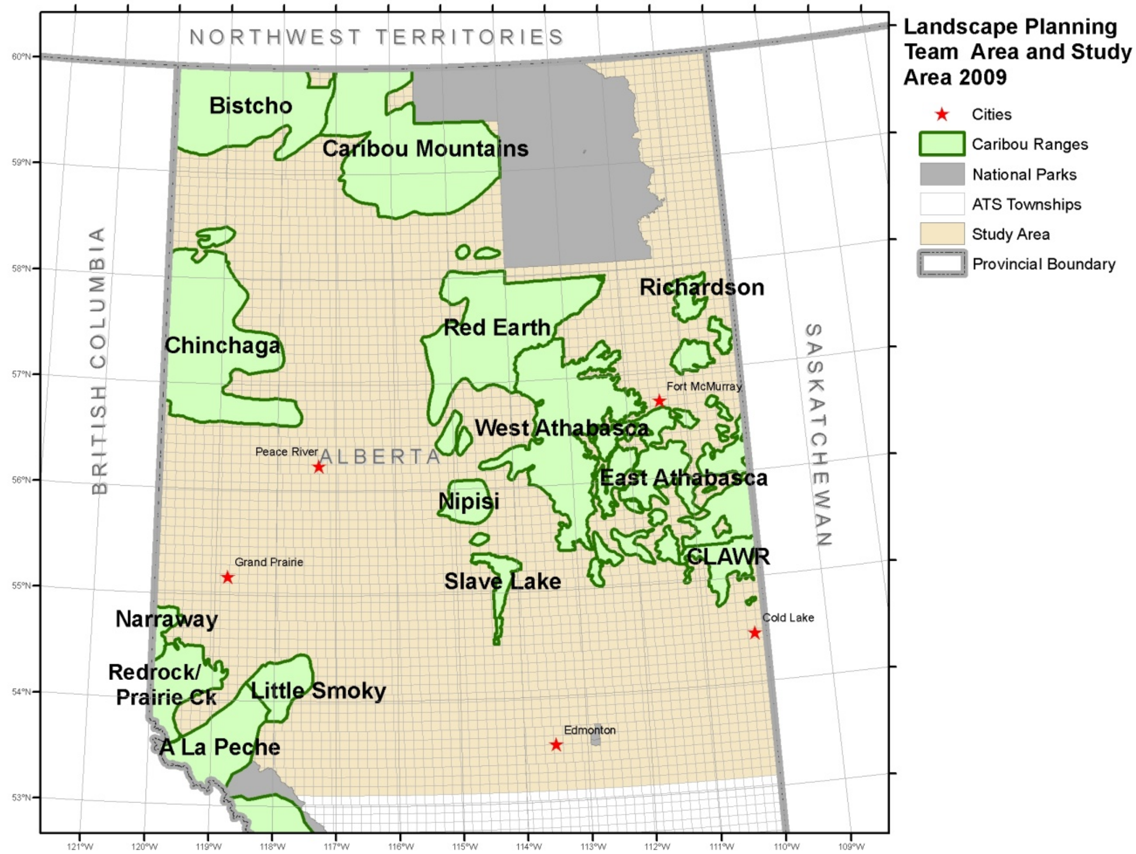



Figure 1. The study area.

## 2. Net present value model of natural gas exploitation

To quantify the value of oil and gas resources, we have developed a new model of the net present value (NPV) of subsurface resources that accounts for the costs and success probabilities of exploration and drilling activity and for the amount of resources remaining to be discovered. The model is first developed from the perspective of a company exploiting one tract (voxel) of resources, which is a combination of an area of land called a land section and geological (stratigraphic) interval.

The model assumes that each section and stratigraphic interval will be exploited separately. This means that cost savings that companies may exploit by planning for exploitation of more than one stratigraphic interval in one place will not be captured in our model. However, the assumption vastly simplifies our model and thus makes it easier to solve. The NPV model varies depending on whether the resources are booked or future resources. For resources that are booked the NPV model for one section/stratigraphic interval (tract) is as follows:

$$NPV = W^{s}\left(C^{DrillComp} + C^{TieIn} + C^{equip} + \sum_{t=1}^{L}\left(\sum_{g}^{G} v_{gt}\left(P_{gt} - C^{oper} - C_{gt}^{Roy}\right)\beta_t - T_t^{ax}\right)\right) \qquad (1)$$

where

$C^{DrillComp}$ = cost of drilling and completing wells;
$C^{DrillAbandon}$ = the cost of drilling and abandoning wells;
$C^{TieIn}$ = the cost of tying in the gas well to the pipeline gathering and processing system.
$C^{equip}$ = the cost of equipment used at the well to extract gas or oil.
$v_{gt}$ = volume of component type $g$ (methane, ethane, butane, propane, pentane, light/medium oil, heavy oil) extracted per well in year $t$;
$W^s$ = number of successful wells required to extract gas given successfully drilled tract;
$L$ = Lifespan of a well;
$P_{gt}$= price of component $g$ (methane, ethane, butane, propane, pentane) in year $t$;
$C^{oper}$ = unit cost of operating the well;
$\beta_t$ = a discount rate set to 0.96 which is equivalent to 0.04 interest rate;
$C_{gt}^{Roy}$ = royalties collected from component $g$ in year $t$;
$T_t^{ax}$=corporate taxes collected in year $t$.

The volume of gas extracted per well per year, $v_{gt}$, is computed based on the initial marketable reserves in the land section and geologic interval and a computed curve of volume extraction curve over time, which we call a volume extraction profile. The volume extraction profile also depends on the number of wells $W^s$ used to extract the resources. The method of computing the extraction profile is described in detail in a following section. The length of time the well operates is implicit in the volume extraction profile and varies from 4 to 34 years (see Table A1).

Many resources classified as booked have wells with production history. In these cases equation 1 is modified as follows:

$$NPV = W^{s}\sum_{t=t_p}^{L}\left(\sum_{g}^{G} v_{gt}\left(P_{gt} - C^{oper} - C_{gt}^{Roy}\right)\beta_t - T_t^{ax}\right) \qquad (2)$$

Here, the initial capital costs are sunk and therefore have been taken out of the equation. The only exception is that $T_t^{ax}$ is affected by initial capital costs (see section on computation of taxes), but this does not change the fact that the initial capital costs are sunk and should be taken out of the equation if the wells are already operating on the landscape. Equation (2) is also different from equation 1 in that the summation over time begins at $t_p$ rather than at 1. The variable $t_p$ is the length of time in years that existing wells have been used to exploit the booked reserves on a particular tract. Here we also made a simplifying assumption and assumed that the all wells on a particular tract started operating at the same time. Where this was not the case, we computed an average starting time for all the known wells still operating and used this for $t_p$. One other difference in equations (1) and (2) is in the computation of the volume extraction profile $v_{gt}$. In equation (1) the profile is based on the initial reserves and an assumed number of wells used to extract the resource, $W^s$, which is computed based on historical averages for the stratigraphic interval and play area (see below for a description). In equation 2, we already know the number of wells $W^s$. We also have information about the cumulative production of the wells from the tract and the length of time the wells have been operating. What remains to be estimated is how much longer the wells will operate, $L$-$t_p$ and the volume extraction profile over this remaining period. The length of time, $L$, that the wells will operate is based on the chosen production profile. We choose the volume extraction profile based on cumulative production over the period $t_p$, rather than initial reserves, and the number of wells currently operating. Again, the method of choosing the extraction profile is explained below. A further complication is that the estimated volume extraction profile may forecast extraction of more or less gas than that remaining at time $t_p$. In cases, where the profile extracts more gas than remaining, we simply truncated the computed profile. In the case that the profile extracted less gas than that remaining, it was assumed that additional wells would be drilled to extract the remaining resources. The NPV model then reverts back to equation 1 since new wells are drilled and initial capital costs must be incurred.

If the tract was designated as having future potential (i.e., not explored but with the right geology), then NPV model was altered to consider the probabilities of successful and failed drilling:

$$\begin{aligned} ENPV = C^{seis} + p^{seis}\Bigg( p^{success} W^{s}\Bigg( & C^{DrillComp} + C^{TieIn} + C^{equip} \\ & + \sum_{t=1}^{L}\left( \sum_{g}^{G} v_{gt}\left(P_{gt} - C^{oper} - C^{Roy}_{gt}\right)\beta_t - T^{ax}_t \right)\Bigg) + p^{success} W^{sa} C^{DrillAbandon} \\ & + \left(1 - p^{success}\right) C^{DrillAbandon} W^{a} \Bigg) \end{aligned} \quad (3)$$

where ENPV (expected NPV) is computed for each well in a land section/stratigraphic interval combination and

$C^{seis}$ = the cost of seismic activities;
$p^{seis}$ = the probability that seismic and/or other information indicates that resources are present in the section and the interval;
$p^{success}$ = probability that drilling activity on the section will result in discovery of oil and/or gas;
$W^{sa}$= number of unsuccessful wells given successfully drilled tract;
$W^{a}$= number of wells abandoned when drilling is unsuccessful;

and all other variables are defined as above. Equation 3 imbeds equation 1 within it and suggests a 3 stage process. In stage one, tracts with appropriate geology, are assessed using seismic testing for which there is a cost $C^{seis}$. The seismic testing yields an indicator that indicates whether resources are present in a section or not. The indicator, however, is not certain because subsequent drilling is not 100% successful. The second stage is drilling, which triggers additional costs associated with drilling. Drilling is successful with probability $p^{success}$ or unsuccessful with probability $1\text{-}p^{success}$. If drilling is successful the well is completed and the cost $C^{DrillComp}$ is incurred, whereas if the well is unsuccessful the cost is $C^{DrillAbandon}$. Based on past drilling data the number of wells is different depending on success or failure. If the drilling is successful in the tract (i.e., the tract has resources) the number of successful wells is $W^s$ and the number of unsuccessful wells in the tract is $W^{sa}$ and if the drilling is unsuccessful (i.e., the tract has no resources) the number of unsuccessful wells is $W^a$. The number $W^{sa}$ in tracts with resources reflects the situation in which there are unsuccessful wells in a tract even if the tract contains resources. In stage 3 the wells are completed and operated to extract gas which leads to further costs of tying in the well to the gas pipeline gathering and processing system, equipment costs, and operating costs. Royalties and taxes are also collected and subtracted from revenues that are generated from operating successful wells $P_{gt}v_{gt}$. Note that the company would proceed with the first stage only if equation 3 is greater than zero. This requires that the condition for drilling, post seismic assessment, is also positive:

$$
\begin{aligned}
&p^{success}W^{s}\Bigg(C^{DrillComp}+C^{TieIn}+C^{equip}\\
&+\sum_{t=1}^{L}\left(\sum_{g}^{G}v_{gt}\left(P_{gt}-C^{oper}-C_{gt}^{Roy}\right)\beta_t-T_t^{ax}\right)\Bigg)+p^{success}W^{sa}C^{DrillAbandon}\\
&+\left(1-p^{success}\right)C^{DrillAbandon}W^{a}\Big)>0
\end{aligned}
\tag{4}
$$

This condition is contained within the outside set of brackets in equation 3.

Figure 2 is a flow diagram outlining the stages in equation 3. Figure 3 is a flow diagram that reflects the overall processing of data that occurs in our model depending on whether resources are booked (equation 1 and 2) or future.

Equations 1 to 4 present an industrial perspective and concern profits. From the government side, the interest will be more in total value of the royalties and taxes, although there is still an interest in 1 to 4 because these profits must be positive if any royalties and taxes are to be generated. The net present value of royalties is :

$$
NPV^{roy}=\sum_{t=1}^{L}\sum_{g}^{G}v_{gt}C_{gt}^{Roy}\beta_t \tag{5}
$$

and the net present value of taxes is:

$$NPV^{tax} = \sum_{t=1}^{L} T_t^{ax} \beta_t \qquad (6)$$

In the following sections, each of the variables identified in equations 1 to 4 are outlined in more detail. First, we describe the data used for reserves and later we will describe the profiles and other variables listed above.

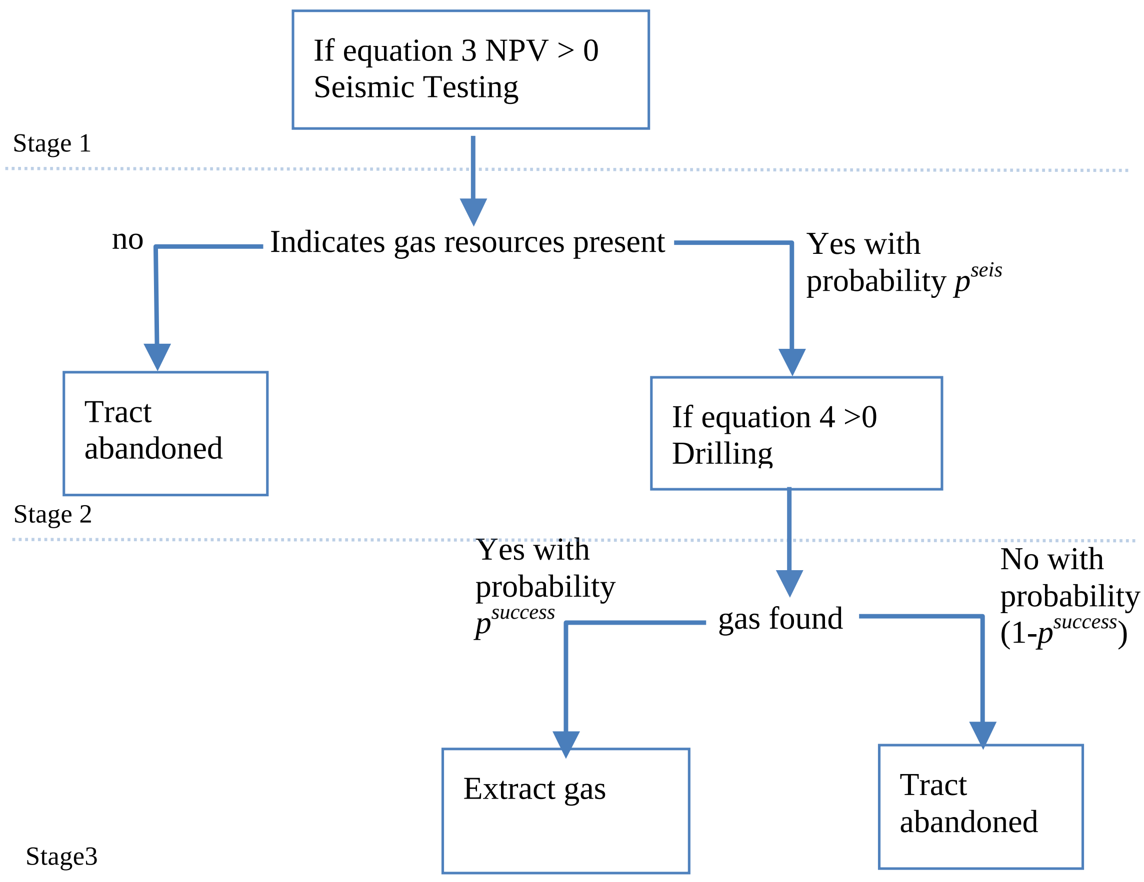



Figure 2. Shows the stages of gas exploration, discovery and extraction found in the expected NPV equation (3).

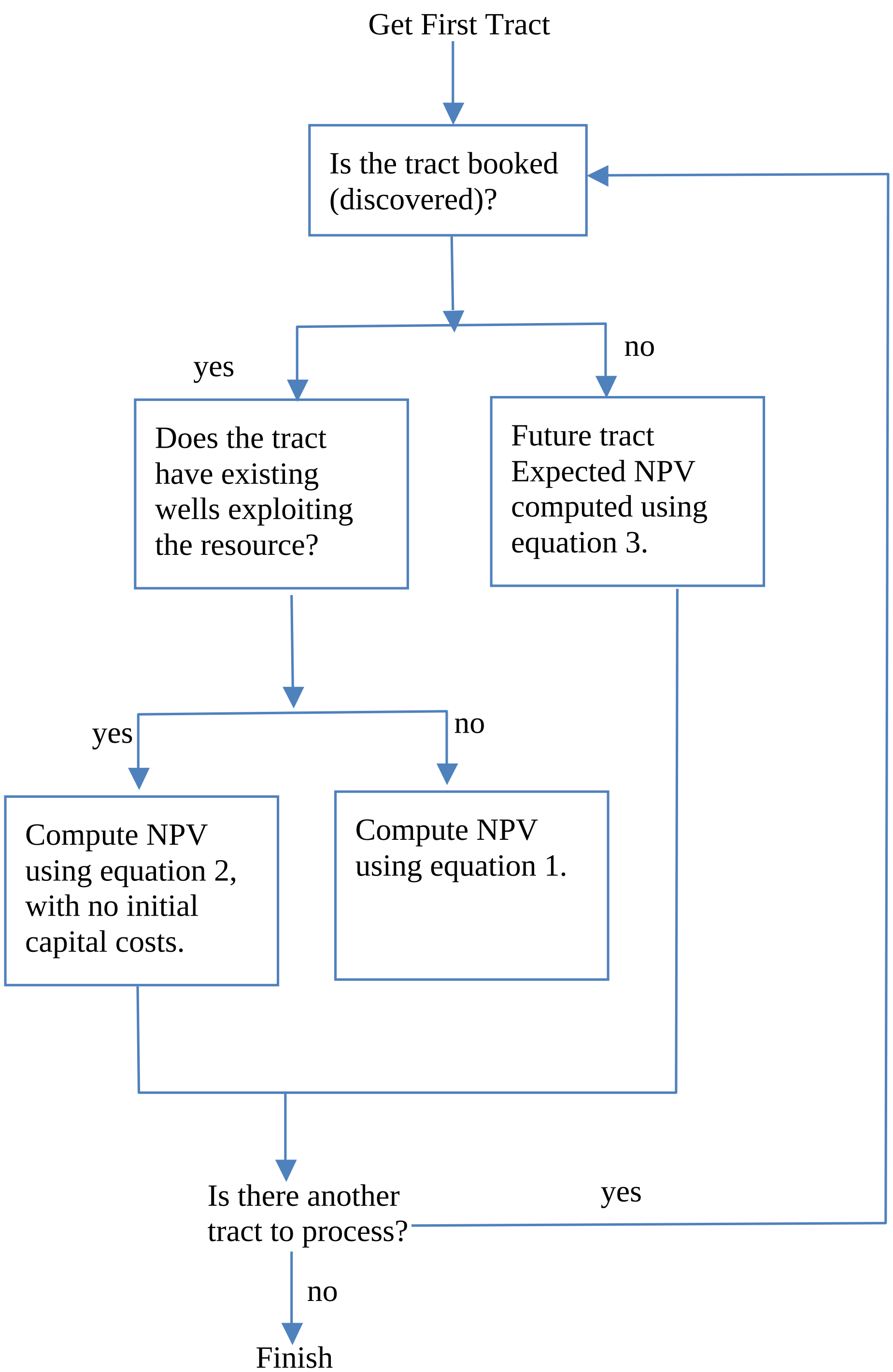



Figure 3. Flow chart showing how tracts are processed.

*Reserves*

For conventional natural gas we use Alberta's ultimate potential for conventional natural gas database (EUB/NEB 2005). Natural gas reserves and future potential of reserves are reported on a section basis, which is an administrative unit of land that is a subsection of a township. Townships are about 10x10 km in size although there is some variation. Sections are typically 1/36 of a township or approximately 277 ha, although they range in size from about 230 ha to 277 ha depending on township size. In the database a section is said to be 256 ha. In some cases there are fewer than 36 sections. For more information on Alberta's township system see Alberta Land Surveyor's Association website at http://www.alsa.ab.ca/alberta-s-township-system.

In each section, Alberta's ultimate potential database divides subsurface resources into vertical stratigraphic intervals based on the study of underlying rock layers (lithology) and geologic time (EUB/NEB 2005). The database recognizes 42 stratigraphic intervals. However, not every stratigraphic interval is represented in each section. Stratigraphic intervals are further subdivided spatially into play areas. This was based on similarity of geology within the stratigraphic intervals. In each play area several parameters are fairly consistent including depth, type of resource (oil, gas, bitumen), gas in place (GIP) per section, and drilling success rate (EUB/NEB 2005).

A combination of play area/stratigraphic interval and a section is referred to as a tract within the database. A tract is a 3D cell that is approximately 256 hectares and one stratigraphic interval in thickness. The volume of a 3D tract depends on both the area of the section (see above) and the thickness of the stratigraphic interval, which varies greatly, depending on the number and thickness of the geological zones that make up the stratigraphic intervals (EUB/NEB 2005). Conventional gas resources are reported by tract.

The following paragraphs follow the description of the ultimate potential database found in (EUB/NEB 2005). Estimation of ultimate potential for conventional natural gas proceeds by first classifying the resources within each tract as:

- booked,
- unbooked,
- unconfirmed,
- bypassed,
- drilled,
- no potential,
- future.

Tracts are classified in hierarchical fashion. If at least one well is drilled into a stratigraphic interval and that well has booked GIP, the whole tract is classified as booked regardless of whether there are wells that do not have booked GIP or geological zones (subintervals) within the tract that do not have wells with no booked GIP. Booked tracts have GIP summed up from one or more recognized pools. Since booked gas pools may cross section boundaries there is the possibility of the presence of booked gas without the presence of a well. Therefore, some tracts may have booked GIP without the presence of the wells. Note that booked resources include both gas that has already been exploited and gas that has yet to be exploited.

Tracts that do not have GIP but that do have wells with more than 500,000 m3 of production are assigned the status of "unbooked". We found that very few tracts are assigned this status within the database, mainly because the administrative process of booking reserves takes time and hence production may be present before a pool has been declared booked. Since the GIP was not known at the time of database construction the tract was assigned the median GIP for the play area.

Unconfirmed tracts are neither booked nor unbooked but have had geological evaluations that indicate some potential. Unconfirmed tracts are assigned the median GIP for the play area. However, because the evaluations are incomplete and there is some uncertainty around about whether gas will actually be found, a probability of success is multiplied by the median GIP to give an estimate of the expected GIP per tract given the uncertainty. In addition, the probability cannot be determined precisely due to the uncertainty and thus the ultimate potential database gives three scenarios for the probabilities. These scenarios are simply named the low, medium and high cases and the probabilities associated with these scenarios are 0.15, 0.30, and 0.45 respectively.

Bypassed tracts do not have booked, unbooked or unconfirmed resources but like unconfirmed resources have had some testing that indicates it may be capable of production and for the time being is not being exploited. Again the GIP for a bypassed tract is the median GIP for the play and the GIP is assigned a probability to reflect the uncertainty for the presence of GIP. In most cases the probabilities assigned to the bypassed tracts are 0.05, 0.10 and 0.15 for the low, medium and high cases respectively.

Tracts are classified as drilled when there is evidence that a well has penetrated the tract and there is either evidence that the well(s) are not capable of production or at the least there is no evidence that the tract is capable of production.

Tracts having no future potential are classified based on the geology of the play, such as lack of trapping mechanisms for gas. Many of these tracts fall within stratigraphic intervals and these areas are labeled as barren play areas.

A tract is classified as future if it is not classified as any of the above (i.e., not booked, unbooked, unconfirmed, bypassed, drilled or no potential). Future tracts fall within play areas where gas has been found in other tracts within the play. GIP is estimated for these tracts based on information from the booked, unbooked, unconfirmed and bypassed tracts. Future potential is again a probability weighted GIP computed by multiplying a probability of success for the stratigraphic interval/play area by the median GIP for the play.    The success probabilities are unique to each play area and is based on the number of tracts in the play that have been drilled and where gas has been found divided by the number of tracts in the play that have been drilled.

Total ultimate potential for each play is computed by summing up all the gas resources over all the tracts in the play.  Total ultimate potential is also the sum of booked, unbooked, unconfirmed, bypassed and future reserves.  Marketable reserves for each tract are computed by multiplying the GIP by a fixed factor unique to each stratigraphic layer/play area.   More information about the classification of resources and computations of ultimate potential can be found in EUB/NEB (2005).

Booked and unbooked reserves are mapped in figure 4.

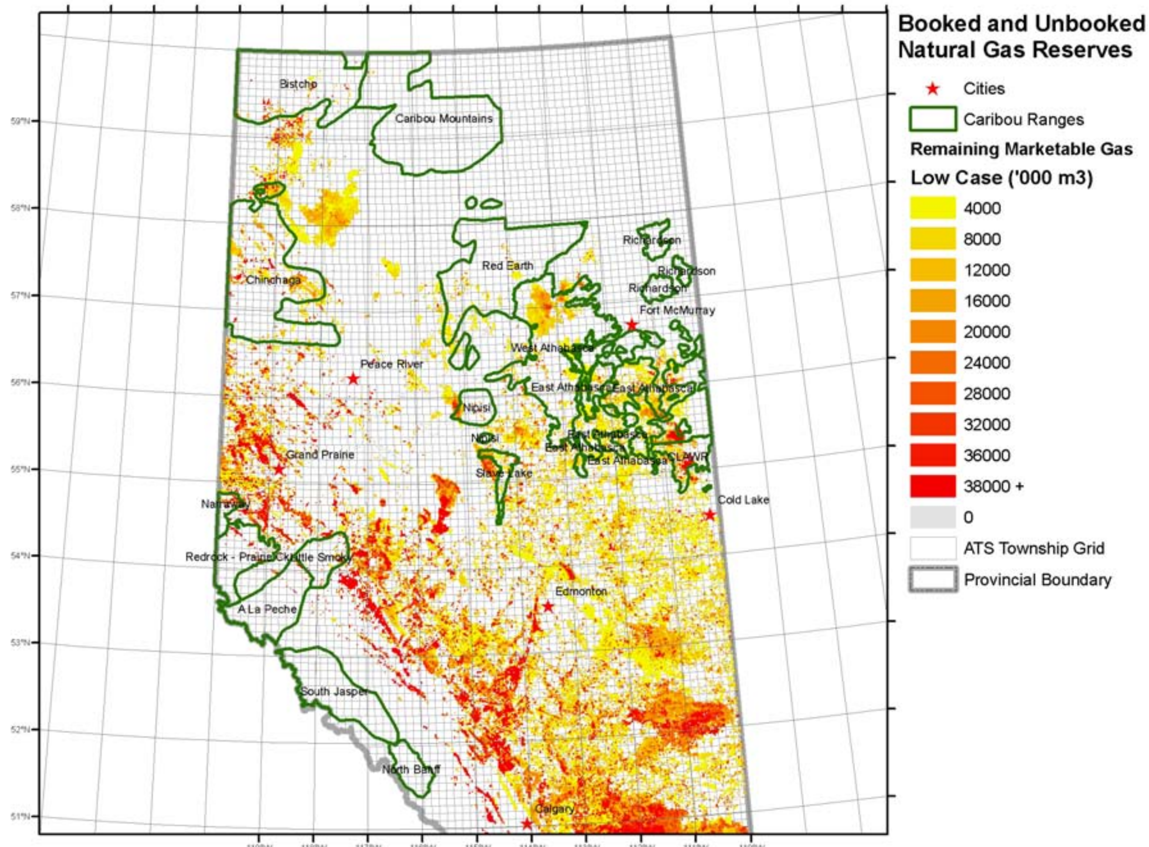



Figure 4.  Booked and unbooked reserves according to the EUB/NEB ultimate potential database.

The ultimate potential estimates for each land section, the sum of the potential within each tract,  is mapped in figures 5, 6 and 7 for the low, medium and high scenarios.

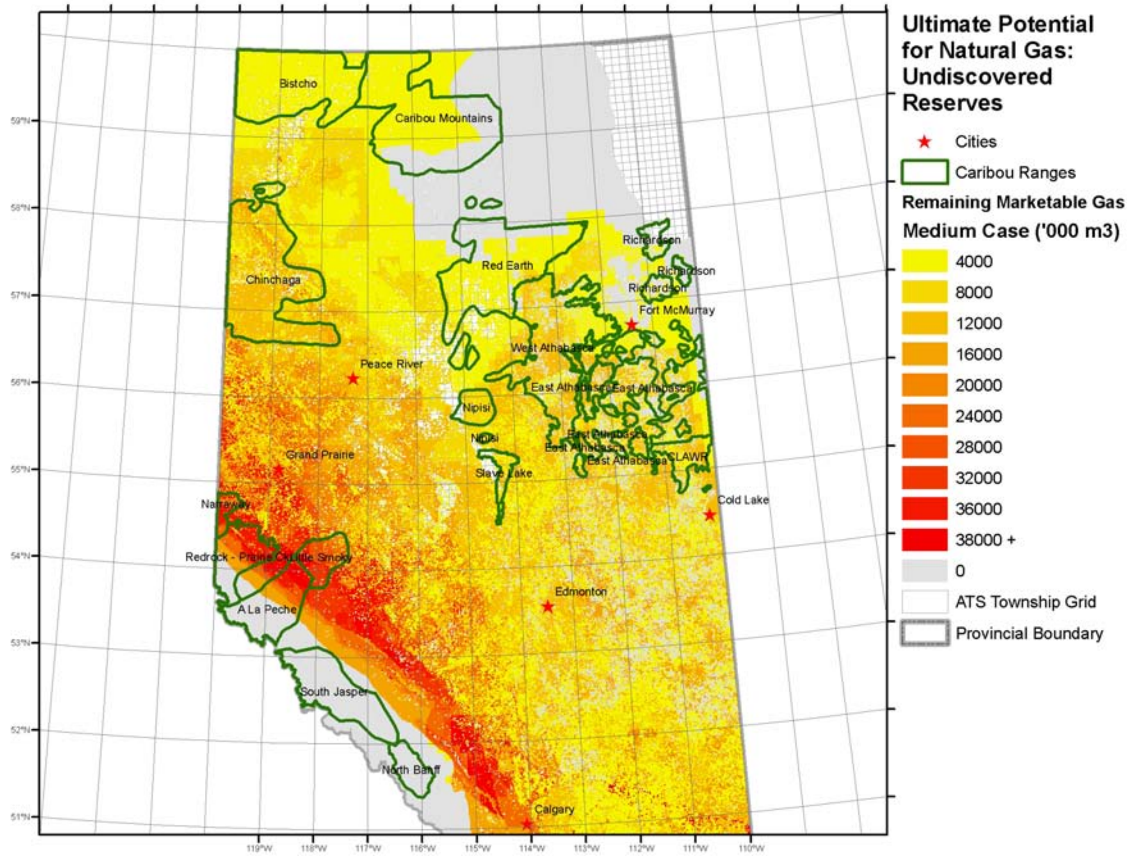



Figure 5. Estimated future, unconfirmed and bypassed resources for the medium scenario from the ultimate potential database.

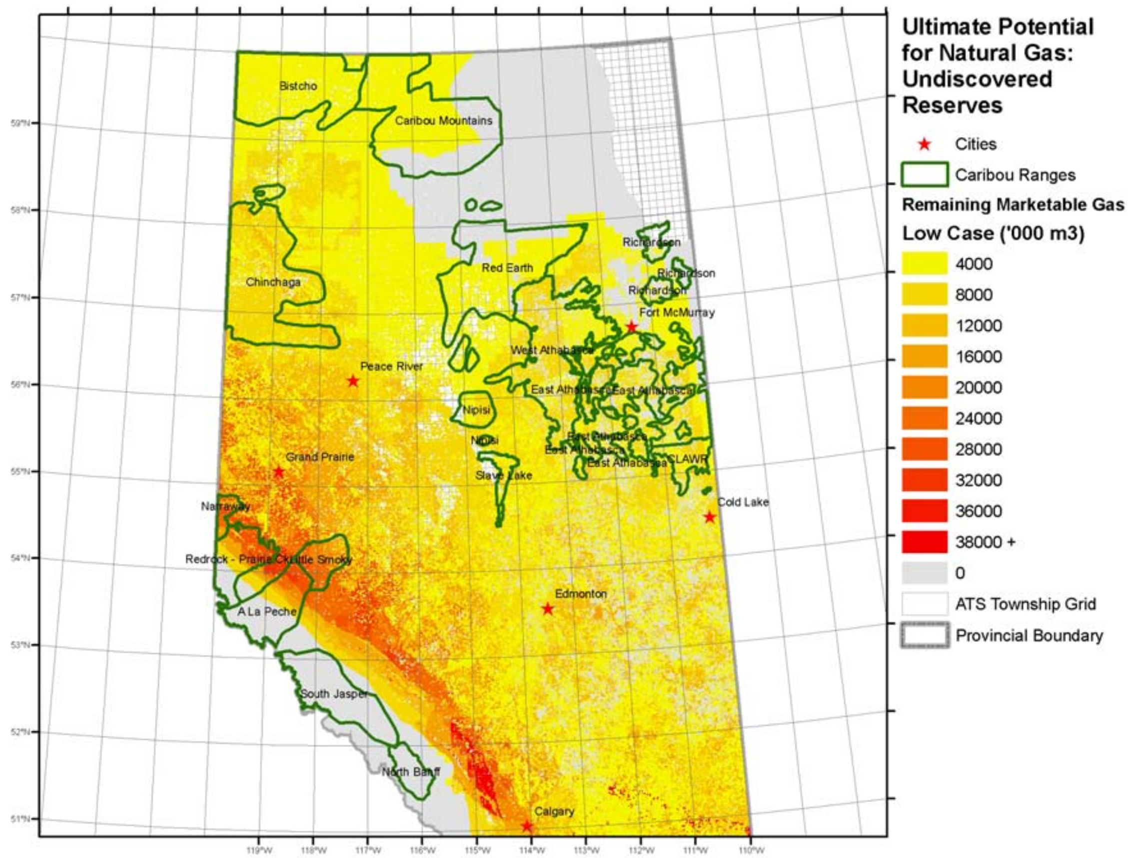



Figure 6. Estimated future, unconfirmed and bypassed resources for the low scenario from the ultimate potential database.

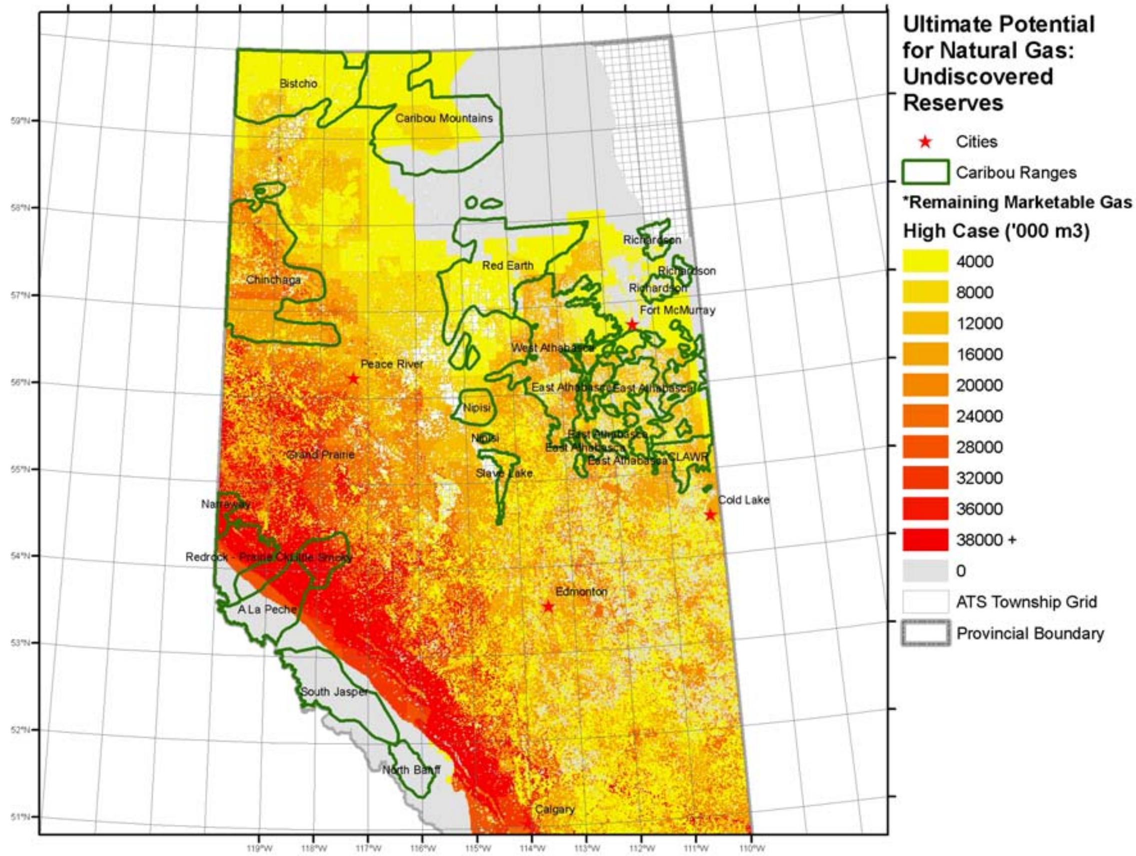



Figure 7. Estimated future, unconfirmed and bypassed resources for the high scenario from the ultimate potential database.

*Volume Extraction over Time*

The volume flow oil or gas extracted from a well ($v_t$) is a variable that responds to changes in prices. However, in this model, the volume flow over time is treated as a fixed set of parameters. This is done primarily for simplicity. In addition, our model removes much of the price fluctuation that would result in well shut-ins by modeling time in 5 year periods. In addition, since the purpose of our modeling exercise is to explore caribou tradeoffs and not price fluctuation, our future price scenarios are smooth projections into the future and do not include price fluctuations.

The volume flow parameters per gas well are derived from profiles presented in a technical background document for Alberta's Royalty Review of 2007 (see Alberta Department of Energy 2007a). Altogether, there are 42 profiles, which are shown in Table A2. There are 6 curves for each PSAC region (Petroleum Services Association of

Canada Regions). For each curve the table shows gas flow in 1000s of m3 for each year, the total flow of gas over the life of the well and the proportion of yearly gas flow with respect to the total flow over the life of the well.

Our approach was to tie the production profiles to each tract based on the amount of marketable gas in the tract, the total flow over a well's life and assumptions about the number of wells that would be used to extract the gas from the tract. For example, if the total amount of marketable gas available in a tract was 2000 m3, and we assume only one well would extract this gas, and if we choose curves specific to PSAC region 3 then this tract would be between curve 1 and 7. We then create weighted average of the two curves proportional to the distance 2000 m3 is between 1133 and 3681 thousand m3 which are the total flows for the two wells. This gives us our expected extraction profile of gas for that tract. This can be expressed in more general terms as a formula,

where:

$$v_t^{R/W^s} = \begin{cases} \dfrac{R/W^s}{P_l} \times v_t^{P_l} \text{ when } \dfrac{R}{W^s} \leq P_l \\ \left(1 - \dfrac{(R/W^s - P_l)}{(P_{l+1} - P_l)}\right) \times v_t^{P_l} + \dfrac{(R/W^s - P_l)}{(P_{l+1} - P_l)} \times v_t^{P_{l+1}} \text{ when there is a } P_l \text{ and } P_{l+1} \text{ such that } P_l \leq \dfrac{R}{W^s} \leq P_{l+1} \\ \dfrac{R/W^s}{P_{42}} \times v_t^{P_{42}} \text{ when } \dfrac{R}{W^s} > P_{42} \end{cases}$$

$R$ is the quantity of gas reserves in the tract in thousands of m3;
$W^s$ is the number of wells extracting gas in the tract;
$v^{R/W^s}$ is the volume extracted from a well in a tract in year t with R thousand m3 of reserves where there are N wells extracting gas;
$P_1, P_2, \ldots, P_l, P_{l+1}, \ldots, P_{41}, P_{42}$. is a list of 42 total production levels over well life (see Table A1) ordered from smallest to largest;
$P_l$ is the well total production level which is the greatest of all production levels less than or equal to $R/W^s$ and $P_{l+1}$ is the well in the list with the smallest total production of all wells with greater production than $R/W^s$.

Figure 8 gives a graphical representation of the above procedure. We have also set up the model to create production profiles that are PSAC region specific. Hence, instead of ordering all 42 wells we first identify the PSAC region and then order the wells profiles (6 in each PSAC region for Alberta) before performing the above operation.

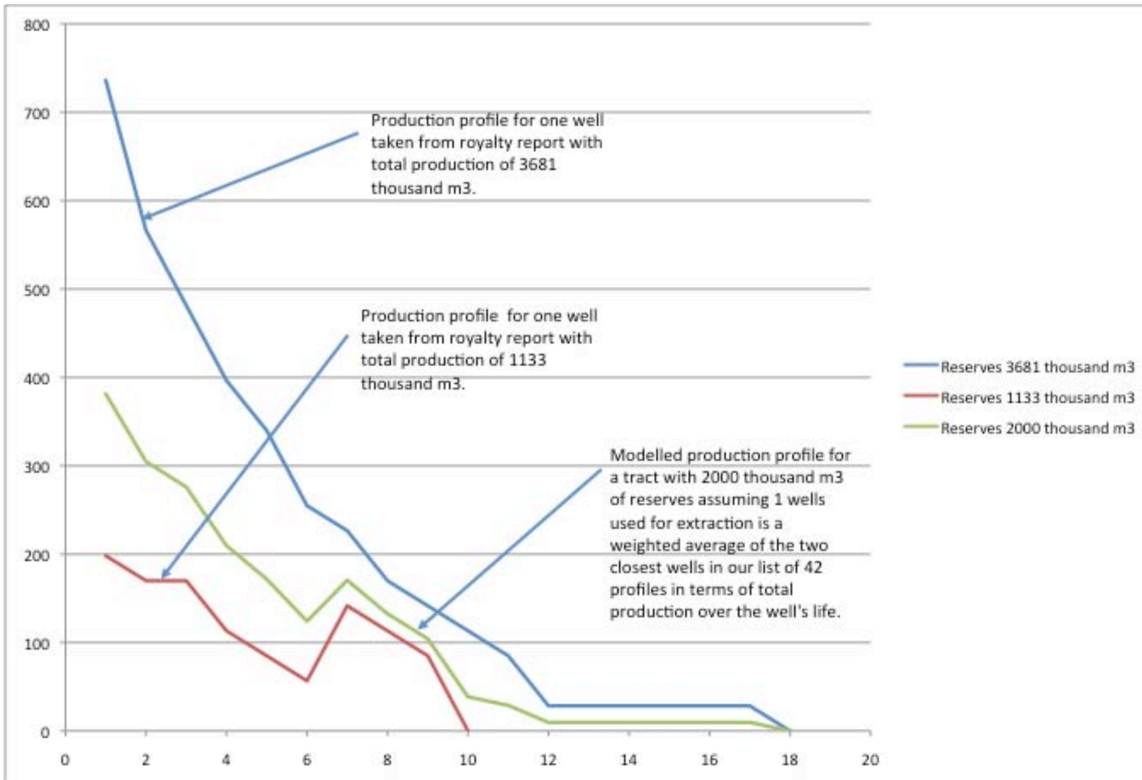


Figure 8. Profiles of production from tracts with reserves are weighted averages of the two closest wells from table A1 in terms of total production.

The above procedure for determining well production profiles for individual tracts was followed as described for tracts with previously unexploited booked reserves, unbooked reserves, unconfirmed reserves, and future potential tracts. For booked reserves in which exploitation was already underway the procedure was modified based on cumulative production at the age of the well in years rather than total production over the lifespan of the well. A weighted average production profile for remaining production was constructed using a similar formula. However, the list of total production over well life $P_1$, $P_2$,….,$P_l$,$P_{l+1}$,…..,$P_{41}$, $P_{42}$ was replaced with a similar list of cumulative production for the average age of the wells currently extracting gas from the tract. In some cases the resulting profile would imply a larger amount of extraction than was actually remaining in the database. In this case the profile was simply truncated so that the production exactly matched the remaining reserves. In other cases the remaining production did not use up the remaining reserves. In that case a new well was modeled and the production profile was constructed as described above.

*Number of Wells per Tract*

In the previous section $W^s$ and $W^a$ denote the number of wells drilled conditional on if the tract is successfully drilled and the number of wells drilled conditional on if the tract is abandoned. Modelling the number of wells drilled is potentially a complex issue because there are many factors that determine how many wells will be drilled to exploit resources in a particular tract. These include the number of discrete pools over which the gas is distributed, the proximity of other pools in other layers and whether old wells can be drilled deeper or whether it is possible for new wells to be drilled out from part way down the main drill hole. Since we are not in possession of such information, we decided to base the number of wells on past data for each stratigraphic interval and play area. Specifically, $W^s$, the number of wells required to extract gas reserves located in a tract, was based on an average number of successful wells per successfully drilled tract. This average was computed for all combinations of stratigraphic interval and play area. The variable, $W^{sa}$, which is the number of unsuccessful or abandoned wells found in a successful tract was computed as the average number of unsuccessful wells per successfully drilled tract. Again this was computed for each strata/play combination. The $W^a$ is the number abandoned wells per tract in which no gas was found. This was computed as the number of wells found on unsuccessful tracts. The data used to compute these averages was obtained by exporting all of the well data from GeoScout. The results are found in table 1.

Table 1. Average number of wells per tract for successful and unsuccessful wells.

| Stratigraphic Interval | Play ID | Ave # of Successful Wells give Successful drilling | Ave # of unsuccessful wells on successful sections | Ave# of wells on unsuccessful sections |
|---|---|---|---|---|
| 1 | 1 | 2.10 | 0.02 | 1.13 |
| 1 | 2 | 1.62 | 0.10 | 1.11 |
| 1 | 3 | 1.04 | 0.00 | 1.00 |
| 2 | 1 | 1.86 | 0.00 | 1.00 |
| 2 | 2 | 2.26 | 0.22 | 1.09 |
| 2 | 3 | 1.79 | 0.04 | 1.05 |
| 2 | 4 | 1.97 | 0.10 | 1.13 |
| 3 | 1 | 1.58 | 0.04 | 1.00 |
| 4 | 1 | 1.50 | 0.50 | 2.00 |
| 4 | 2 | 5.21 | 0.00 | 1.00 |
| 4 | 3 | 1.71 | 0.03 | 1.17 |
| 4 | 4 | 1.59 | 0.02 | 1.02 |
| 4 | 10 | 1.30 | 0.47 | 1.17 |
| 5 | 1 | 4.82 | 0.03 | 1.23 |
| 5 | 2 | 1.65 | 0.04 | 1.21 |
| 5 | 3 | 1.96 | 0.02 | 1.00 |
| 6 | 1 | 1.73 | 0.00 | 1.00 |
| 6 | 2 | 2.15 | 0.01 | 1.17 |
| 6 | 10 | 1.00 | 0.00 | 1.16 |
| 7 | 1 | 1.16 | 0.00 | NA |
| 7 | 2 | 1.00 | 0.00 | NA |
| 7 | 3 | 1.48 | 0.00 | 1.00 |
| 8 | 1 | 1.28 | 0.19 | 1.13 |
| 8 | 2 | 1.95 | 0.14 | 1.12 |
| 8 | 3 | 1.39 | 0.11 | 1.12 |
| 8 | 4 | 1.65 | 0.04 | 1.07 |
| 9 | 1 | 2.95 | 0.67 | 1.14 |
| 9 | 2 | 1.00 | 0.00 | 1.00 |
| 10 | 1 | 1.39 | 0.03 | 1.04 |
| 10 | 2 | 2.36 | 0.51 | 1.07 |

Table 1 continued. Average number of wells per tract for successful and unsuccessful wells.

| Stratigraphic Interval | Play ID | Ave # of Successful Wells give Successful drilling | Ave # of unsuccessful wells on successful sections | Ave# of wells on unsuccessful sections |
|---|---|---|---|---|
| 11 | 1 | 1.39 | 0.04 | 1.04 |
| 11 | 2 | 1.04 | 0.00 | 1.04 |
| 11 | 3 | 3.67 | 0.03 | 1.13 |
| 12 | 1 | 2.25 | 0.03 | 1.00 |
| 12 | 2 | 1.12 | 0.00 | 1.00 |
| 12 | 3 | 1.99 | 0.02 | 1.08 |
| 13 | 1 | 1.21 | 0.14 | 1.05 |
| 13 | 2 | 1.33 | 0.03 | 1.05 |
| 13 | 3 | 1.68 | 0.11 | 1.04 |
| 13 | 4 | 1.36 | 0.04 | 1.04 |
| 13 | 5 | 1.53 | 0.04 | 1.07 |
| 13 | 6 | 1.21 | 0.01 | 1.08 |
| 14 | 1 | 1.20 | 0.04 | 1.05 |
| 15 | 1 | 1.11 | 0.00 | 1.12 |
| 15 | 2 | 2.13 | 0.28 | 1.19 |
| 15 | 3 | 1.96 | 0.31 | 1.28 |
| 15 | 4 | 1.11 | 0.09 | 1.07 |
| 16 | 1 | 2.00 | 0.07 | 1.79 |
| 16 | 2 | 1.26 | 0.02 | 1.07 |
| 16 | 3 | 1.15 | 0.03 | 1.05 |
| 16 | 4 | 1.45 | 0.02 | 1.02 |
| 17 | 1 | 1.33 | 0.01 | 1.02 |
| 18 | 1 | 1.93 | 0.13 | 1.13 |
| 18 | 2 | 1.07 | 0.18 | 3.50 |
| 19 | 1 | 1.00 | 0.00 | 1.00 |
| 19 | 2 | 1.20 | 0.03 | 1.10 |
| 19 | 3 | 1.32 | 0.03 | 1.03 |
| 20 | 1 | 1.76 | 0.24 | 1.11 |
| 20 | 2 | 1.18 | 0.10 | 1.05 |
| 20 | 3 | 1.06 | 0.06 | 1.04 |
| 21 | 1 | 1.36 | 0.39 | 1.33 |
| 21 | 2 | 5.00 | 1.64 | 1.24 |
| 21 | 3 | 1.27 | 0.27 | 1.13 |
| 21 | 4 | 1.32 | 0.06 | 1.08 |
| 21 | 5 | 1.00 | 0.00 | 1.00 |
| 22 | 1 | 1.00 | 0.00 | 1.00 |
| 22 | 2 | 1.60 | 0.08 | 1.06 |
| 22 | 3 | 1.21 | 0.07 | 1.09 |
| 22 | 4 | 1.30 | 0.02 | 1.02 |
| 23 | 1 | 1.16 | 0.04 | 1.07 |
| 24 | 1 | 1.06 | 0.39 | 1.11 |
| 24 | 2 | 1.82 | 0.13 | 1.05 |
| 25 | 1 | 2.47 | 0.25 | 1.12 |
| 26 | 2 | 1.56 | 0.10 | 1.09 |

Table 1 continued. Average number of wells per tract for successful and unsuccessful wells.

| Stratigraphic Interval | Play ID | Ave # of Successful Wells give Successful drilling | Ave # of unsuccessful wells on successful sections | Ave# of wells on unsuccessful sections |
|---|---|---|---|---|
| 27 | 1 | 1.00 | 0.00 | NA |
| 27 | 2 | 1.44 | 0.13 | 1.07 |
| 28 | 1 | 1.05 | 0.00 | 1.00 |
| 28 | 2 | 1.60 | 0.14 | 1.08 |
| 29 | 1 | 1.00 | 0.00 | 1.00 |
| 29 | 2 | 1.32 | 0.07 | 1.03 |
| 30 | 1 | 1.10 | 0.06 | 1.03 |
| 31 | 1 | 1.23 | 0.30 | 1.23 |
| 31 | 2 | 1.59 | 0.70 | 1.36 |
| 31 | 3 | 1.24 | 0.12 | 1.07 |
| 31 | 4 | 2.04 | 0.20 | 1.09 |
| 31 | 5 | 1.10 | 0.07 | 1.05 |
| 32 | 1 | 1.20 | 0.07 | 1.05 |
| 32 | 2 | 1.06 | 0.00 | 1.00 |
| 33 | 1 | 1.00 | 0.00 | 1.00 |
| 33 | 2 | 1.59 | 0.41 | 1.29 |
| 33 | 3 | 1.56 | 0.16 | 1.06 |
| 33 | 4 | 1.27 | 0.07 | 1.04 |
| 33 | 5 | 1.03 | 0.00 | 1.05 |
| 34 | 1 | 1.51 | 0.35 | 1.14 |
| 34 | 2 | 1.93 | 0.45 | 1.17 |
| 34 | 3 | 1.04 | 0.08 | 1.04 |
| 34 | 4 | 1.22 | 0.05 | 1.08 |
| 35 | 1 | 1.57 | 0.18 | 1.06 |
| 36 | 1 | 1.30 | 0.21 | 1.17 |
| 36 | 2 | 1.19 | 0.26 | 1.15 |
| 36 | 3 | 1.20 | 0.18 | 1.10 |
| 36 | 4 | 1.09 | 0.14 | 1.09 |
| 36 | 5 | 1.08 | 0.00 | 1.04 |
| 36 | 6 | 1.64 | 0.58 | 1.18 |
| 36 | 7 | 1.18 | 0.06 | 1.05 |
| 36 | 8 | 1.00 | 0.00 | 1.06 |
| 37 | 1 | 1.61 | 0.12 | 1.26 |
| 37 | 2 | 2.69 | 0.31 | 1.05 |
| 37 | 3 | 1.26 | 0.14 | 1.14 |
| 37 | 4 | 1.23 | 0.04 | 1.36 |
| 37 | 5 | 1.08 | 0.10 | 1.07 |
| 37 | 6 | 1.12 | 0.03 | 1.06 |
| 37 | 7 | 1.65 | 0.13 | 1.02 |
| 38 | 1 | 1.44 | 0.10 | 1.04 |
| 38 | 2 | 1.09 | 0.08 | 1.05 |
| 38 | 3 | 1.17 | 0.10 | 1.03 |
| 38 | 4 | 1.70 | 0.22 | 1.11 |
| 38 | 5 | 1.85 | 0.46 | 1.16 |

Table 1 continued. Average number of wells per tract for successful and unsuccessful wells.

| Stratigraphic Interval | Play ID | Ave # of Successful Wells give Successful drilling | Ave # of unsuccessful wells on successful sections | Ave# of wells on unsuccessful sections |
|---|---|---|---|---|
| 38 | 6 | 2.17 | 0.64 | 1.30 |
| 38 | 7 | 1.17 | 0.00 | 1.00 |
| 38 | 8 | 1.74 | 0.35 | 1.16 |
| 38 | 9 | 1.23 | 0.19 | 1.19 |
| 39 | 1 | 1.19 | 0.09 | 1.04 |
| 39 | 2 | 2.00 | 0.33 | 1.11 |
| 39 | 3 | 2.23 | 0.17 | 1.02 |
| 39 | 4 | 1.12 | 0.12 | 1.15 |
| 39 | 5 | 1.14 | 0.08 | 1.02 |
| 39 | 6 | 1.01 | 0.04 | 1.00 |
| 39 | 7 | 1.05 | 0.00 | 1.19 |
| 39 | 8 | 1.45 | 0.14 | 1.09 |
| 39 | 9 | 1.57 | 0.23 | 1.00 |
| 40 | 1 | 1.28 | 0.09 | 1.02 |
| 40 | 2 | 2.05 | 0.68 | 1.21 |
| 41 | 1 | 1.19 | 0.02 | 1.00 |
| 41 | 2 | 1.01 | 0.00 | 1.04 |
| 42 | 1 | 2.52 | 0.49 | 1.10 |
| 42 | 2 | 2.03 | 0.27 | 1.04 |
| 42 | 3 | 1.85 | 0.26 | 1.11 |
| 42 | 4 | 1.23 | 0.12 | 1.04 |
| 42 | 5 | 2.00 | 0.00 | 1.10 |

*Attaching wells to stratigraphic intervals*

Within the energy component of our model depths of various strata are essential to the analysis of drilling costs. The deeper a proposed well is the greater the drilling costs. While depth data was used in constructing the Ultimate Potential Database is was not included in the database itself and was thus not available (EUB/NEB 2005). However, drilling depth data for many thousands of wells is available. Our approach for estimating depth for stratigraphic intervals, was to first attach wells to stratigraphic intervals and then use the depth data from the wells to estimate depths of stratigraphic intervals. Available well data was supplied by Geoscout, which is a software program that allows the user to view maps showing the location of wells, call up detailed information for each well in the province, and other functions. The program also allows the user to create output databases of well data such as production, depth, pool names and formations penetrated. Our approach was to link wells to the stratigraphic layers based on a table (see EUB/NEB 2005) in the Ultimate potential data that tells which formations are incorporated in each stratigraphic layer. This table is recreated as Table 2. While the approach was simple in concept it was more difficult to execute because the formation names in Geoscout were not standard and/or there were many sublayers within formation.

Hence, we need to link formation names in Geoscout to the formation names seen in the right column of Table 2. The steps involved in this process were specifically:

1. Enumerate the formation names in the geoscout database. In the Geoscout database these fields were labeled Proj Fm., Formation at TD (total depth), etc.
2. Cross reference the formation names with the table in the appendix of report r2005-a (see table 2 above). If there is a direct match assign the name of the stratigraphic ID in the column to the right of the formation name. In many cases the formation name matched a name in the right column of Table 2 exactly.
3. However, in many cases project name did not match exactly to the names in Table 2. A second table was created that that matched many variations of formation names and others in the Table 2 to the stratigraphic IDs. This table is many thousands of lines long and cannot be replicated here. Table 3 is a small excerpt from this larger table.

Table 2. Shows how formations are related to stratigraphic intervals in the ultimate potential database. The table is recreated from r2005-A report by EUB/NEB.

| Strat ID | Stratigraphic interval | Zones (group, formation, member) |
|---|---|---|
| 1 | Paskapoo&Edmonton | Quaternary, Paskapoo, Edmonton, Horseshoe Canyon |
| 2 | BellyRiver | Wapiti, Bearpaw, Belly River, Brazeau, Oldman, Foremost, Ribstone Creek, Victoria, Brosseau |
| 3 | Chinook | Chinook |
| 4 | MilkRiver | MilkRiver |
| 5 | MedicineHat | MedicineHat |
| 6 | Colorado | Colorado |
| 7 | LowerColorado&Badheart | FirstWhiteSpecks, Badheart, Lower Colorado |
| 8 | Cardium | Cardium |
| 9 | DoeCreek | DoeCreek |
| 10 | Dunvegan | Dunvegan |
| 11 | SecondWhiteSpecks | Second White Specks |
| 12 | FishScales | FishScale, Barons, BaseFishScales |
| 13 | Viking | BowIsland, Viking, Provost, Hamilton Lake, PeaceRiver, Paddy, Cadotte |
| 14 | BasalColorado | BasalColorado |
| 15 | MannvilleAboveGlauconitic | Viking-Blairmore, MountainPark, Blairmore, Mannville, Upper Mannville, Colony, Grand Rapids, SpiritRiver, Notikewin, McLaren, Waseca, Falher, Sparky, Wainwright, Clearwater, General Petroleum, Rex, Lloydminster |
| 16 | Glauconitic | Home, Glauconitic, Cummings, Cummings-Dina, Bluesky, Bluesky-Gething, Wabiskaw, Moulton |
| 17 | Ostracod | Ostracod |
| 18 | Ellerslie | Wabiskaw-McMurray, Lower Blairmore, Lower Mannville, BasalMannville, Dina, Gething, McMurray, Sunburst, Sunburst-Swift, Basal Quartz, Ellerslie, Cutbank, Taber, Detrital |
| 19 | Cadomin | Dalhousie, Cadomin |
| 20 | Nikanassin | Kootenay, Nikanassin, Morrissey |
| 21 | RockCreek&Sawtooth | Swift, Sawtooth, Rock Creek |
| 22 | Nordegg | Nordegg, Nordegg-Banff, Jurassic, Jurassic Detrital |
| 23 | Baldonnel | Baldonnel |
| 24 | CharlieLake | Charlie Lake |
| 25 | Boundary | Boundary |
| 26 | Halfway | Halfway |
| 27 | Doig | Doig |
| 28 | Montney | Bluesky-Montney, Spray River, Montney, Bluesky-Gething-Montney, Bluesky-Triassic |
| 29 | Belloy | Belloy |
| 30 | Kiskatinaw&TaylorFlat | TaylorFlat, Kiskatinaw |
| 31 | TurnerValley | Bluesky-Debolt, Rundle, Debolt, MountHead, Livingstone, TurnerValley, Elkton, Elkton-Shunda |
| 32 | Shunda | Shunda |
| 33 | Pekisko | Shunda-Pekisko, Pekisko |
| 34 | Banff | Banff |
| 35 | Bakken | Bakken |
| 36 | WabamunCrossfield | Palliser, Wabamun, Big Valley, Crossfield |
| 37 | WinterburnNisku | Winterburn, Graminia, Blueridge, Arcs, Nisku, JeanMarie, CamroseTongue |
| 38 | Leduc&Grosmont | Woodbend, Ireton, Grosmont, Peechee, Leduc, Cairn, CookingLake |
| 39 | SwanHills&SlavePoint | BeaverhillLake, Swan Hills, SlavePoint, Slave Point-GraniteWash |
| 40 | Gilwood&GraniteWash | Gilwood, GraniteWash |
| 41 | SulphurPoint | SulphurPoint |
| 42 | Zama&KegRiver | Muskeg, Zama, Zama-Keg River, KegRiver, Winnipegosis |

Table 3. Shows how formation names and abbreviations found in GeoScout data base are related to stratigraphic intervals in the ultimate potential database. The actual table has over 10,000 lines and cannot be fully replicated here.

| Formation Code | Formation Name | Formation Abbrev | Strat ID for Depositional/Erosional Edges | Strat ID for Deepest Penetrated Formation |
|---|---|---|---|---|
| 6440 | BANFF FM | BNFF | 34 | 34 |
| 6441 | BANFF POOL NO. 1 | BANFF #1 | 0 | 0 |
| 6442 | BANFF SS | BNFF SS | 34 | 34 |
| 6445 | UPPER BANFF | U BNFF | 34 | 34 |
| 6449 | BASE OF BANFF | BS BNFF | 34 | 34 |
| 6450 | MIDDLE BANFF | M BNFF | 34 | 34 |
| 6455 | LOWER BANFF | L BNFF | 34 | 34 |
| 6457 | BANFF SHALE | BNFF SH | 0 | 34 |
| 6460 | BAKKEN FM | BAKN | 35 | 35 |
| 6469 | BASE OF BAKKEN | BS BAKN | 35 | 35 |
| 6480 | EXSHAW FM | EX | 0 | 34 |
| 6481 | EXSHAW-WABAMUN | EX-WAB | 0 | 0 |
| 6499 | REWORKED DEVONIAN | RWKD DEV | 36 | 36 |
| 6500 | DEVONIAN SYSTEM | DEV SYS | 36 | 36 |
| 6520 | UPPER DEVONIAN | U DEV | 0 | 0 |
| 6540 | PALLISER FM | PALL | 36 | 36 |
| 6560 | COSTIGAN MBR | COST | 36 | 36 |
| 6580 | WABAMUN GRP | WAB | 36 | 36 |
| 6581 | WABAMUN GRP | WAB | 0 | 0 |
| 6585 | WABAMUN-WINTERBURN | WAB-WINT | 0 | 0 |
| 6586 | WABAMUN & NISKU | WAB&NIS | 0 | 0 |
| 6590 | WABAMUN-GRAMINIA | WAB-GRAM | 36 | 36 |
| 6591 | WABAMUN & BLUERIDGE | WAB&BLUE | 0 | 0 |
| 6592 | WABAMUN-CALMAR | WAB-CALM | 0 | 0 |

*Assigning Depths to strata with no linked wells*

Within the energy component of Tardis, depths of various strata are essential to the analysis of drilling costs. The deeper a proposed well is the greater the drilling costs. In theory there are over 4 million tracts that could potentially be drilled. This figure is obtained from the ultimate potential database, which is subdivided into townships, sections, and stratigraphic IDs giving approximately 4.19 million records within the database.

While depth data was used in constructing the Ultimate Potential Database it was not included in the database itself and was thus not available. Hence, a procedure for estimating depths for stratigraphic intervals was essential. Depths can be obtained directly from the well data downloaded from the GeoScout database. However, this can only be done for tracts that have wells linked to them using the procedure described in the previous section. In some cases wells do not have recorded depths. But wells are also attached to pools and there is a EUB pool database that contains average depths for the pools. Both of these data sources were used to estimate depths of tracts where wells are linked to stratigraphic intervals. If depth data from the GeoScout well database was available then this data was used to estimate the depth of the tract. If depth data was not available for a well attached to a tract, then the average depth for the pool was assigned to the tract.

Since wells are heterogeneously distributed and the number of wells in our database is less than 400,000 there are many tracts that were not assigned a depth using this method. Most of these tracts would be classified as future potential in the ultimate potential database because they have not yet been explored. Hence, a method was required for assigning depths to tracts that did not have wells linked to them. In that case, a two step procedure was followed. First, we assigned depths to tracts in townships in which there was at least one other tract with depth information. In this case, those tracts which had depths were used to compute an average depth for the strata/play within the township. This average was then assigned to any tract with no depth information. Note, there are 36 sections in a township so the maximum number of tracts assigned a depth would be 35, if only one tract had depth information. The second step was to fill in tract depths for all townships/strata play combinations in which not a single tract had depth information. We used a nearest neighbour principle to fill in the depths in this case. Overall the procedure for assigning depths to tracts without assigned depths may be described as follows:

1. For all tracts with linked gas wells
    a. Compute an average depth for all wells in the tract and assign the mean depth to the tract. If a well does not have depth data, then use the average depth for the pool for that well.

2. For each township/strata/play combination with at least one tract assigned a depth:
    a. Assign tracts within the townships, not already assigned a depth, the average of the depths assigned to tracts in step 1.

3. For each stratigraphic interval/play id
    a. For each township in the interval that has adjacent townships with depth data
        i. Get the average depth of all adjacent townships with assigned depth data for the current stratigraphic interval.
        ii. Assign the average depth to the township-stratigraphic interval

Thus stratigraphic layers within townships that do not have depth data are assigned a depth based on the average depths in neighbouring townships. The algorithm takes several passes to fill in the depths because many township-stratigraphic intervals may be 1 or more townships from a township with actual well data. Hence, on the first pass townships with neighbours containing data from drilling records are filled with average depth data from those neighbours. Townships that are more than one township away are left untouched on the first pass. On the second pass townships that are more than 1 township away are filled with average depths computed on the previous pass and so on until the entire stratagraphic interval is filled with depth data. Clearly this is only an estimate and their may be errors. Other statistical approaches are available to estimate depths however, time and resources were not available to pursue this.

*Drilling cost model*

Drilling costs were estimated using a regression model developed from the Petroleum Services Association Well Cost Studies (PSAC) from 2005-2008. The well costs studies provide costs for one or more wells within each of 15 PSAC regions across Canada. The wells are a list of "typical wells" and the selection of wells depends on the most recent interests of the drilling industry in terms of exploration activity such as horizontal drilling, oilsands, and coal bed methane (PSAC 2008). The drilling costs studies provide information on total drilling and completions costs as well as abandonment costs, but also provide information on drilling depth, fuel costs, horizontal depth and many other variables. One regression model was developed for drilling and abandonment costs and another for drilling and completion costs. Selected explanatory variables for the model were total vertical depth, horizontal depth, rig transport distance, and fuel costs. All variables expressed in dollars were adjusted for inflation using the consumer price index and are expressed in 2009 dollars. The regression results for the two models are presented in Table 4 and Table 5. The dependent variables were drilling and completion cost; and drilling and abandonment costs. The explanatory variables used are total measured depth of the well in meters, and the amount horizontal depth in meters, the rig transport distance in kilometers, fuel cost in $/litre, and a set of dummy variables that indicate various PSAC regions. The total measured depth of the well includes the total well length along the well hole, including any change in horizontal direction. This is to distinguish another common measure of depth, which is total vertical depth, which obviously does not include horizontal distance. The total measure depth was included in the model with a Box-Cox transformation to account for the non-linear response of drilling cost with depth. The transformation was as follows:

$$BoxCox(2.5) = \frac{\left(Depth^{2.5} - 1\right)}{2.5}$$

The model also includes horizontal depth, which is the horizontal distance from the top of the well hole to the bottom of the well hole. Rig transport distance is the distance in kilometers the drilling rig was transported from its last location.

The regression model was used to estimate the cost of drilling and completing ($C_{DrillComp}$); and drilling and abandoning ($C_{DrillAbandon}$) wells in the *NPV* equations shown in equations 1 to 4.

In the net present value model fuel cost, rig transport distance, road distance and road building costs were set by PSAC region and were set as the averages of the data for each PSAC region. These averages are presented in table 5. For horizontal depth averages were taken for each stratigraphic interval and play area. While there were horizontal distances in many of the wells in the database they were by far in the minority and hence horizontal depth averages were in all cases close to zero.  Hence this variable was set to zero for all stratigraphic intervals and play areas.

Table 4. Drilling and Completion model.

| | *Drilling and Completion Cost Model* | | | *Drilling and Abandon Cost Model* | | |
|---|---|---|---|---|---|---|
| | *Coefficients* | *Standard Error* | *P-value* | *Coefficients* | *Standard Error* | *P-value* |
| Intercept | -559576.4 | 284208.8 | 0.05 | -642191.8 | 279280.9 | 0.02 |
| Horizontal Depth (m) | -169.8440 | 104.6737 | 0.10 | -191.5974 | 102.8588 | 0.06 |
| Rig Transport Dist. (km) | 913.1331 | 332.3388 | 0.006 | 910.2476 | 326.5764 | 0.006 |
| Fuel Cost ($/L) | 967433.9 | 335037.1 | 0.004 | 779900.7 | 329227.9 | 0.018 |
| Total Measured Depth (m) Box Cox Trans. 2.5 | 0.014755 | 0.000347 | 0.000 | 0.013426 | 0.000341 | 0.000 |
| BC2 | 622273.3 | 123621.2 | 0.000 | 469150.9 | 121477.7 | 0.000 |
| AB1 | 2306088. | 218994.8 | 0.000 | 1925585. | 215197.7 | 0.000 |
| AB2 | -586460.3 | 152792.0 | 0.000 | -894709.1 | 150142.7 | 0.000 |
| AB5 | -137334.0 | 99890.31 | 0.170 | -108010.7 | 98158.31 | 0.272 |
| AB7 | -191551.0 | 99067.34 | 0.05 | -260329.0 | 97349.61 | 0.008 |
| SK3 | -344571.1 | 141473.4 | 0.015 | -374973.8 | 139020.4 | 0.007 |
| Model Statistics | | | | | | |
| R Square | | | 0.96139 | | | 0.95285 |
| Standard Error | | | 483880 | | | 475490 |
| Observations | | | 245 | | | 245 |

Table 5. Averages of explanatory variables in drilling cost model by PSAC region.

| PSAC Region | FuelCost ($/litre) | Drill Rig Transport Distance (km) | Road Distance (km) | Road $/km |
|---|---|---|---|---|
| 1 | 0.87 | 161 | 5 | 15623 |
| 2 | 0.87 | 164 | 5.34 | 9855.6 |
| 3 | 0.87 | 60 | 1.05 | 6153.6 |
| 4 | 0.87 | 65 | 0.5 | 6632.8 |
| 5 | 0.87 | 92 | 1.75 | 5833.2 |
| 6 | 0.87 | 84 | 1 | 5195.0 |
| 7 | 0.87 | 155 | 2.53 | 5195.6 |

*Operating Costs*

Operating costs ($C_{oper}$) per unit extracted (m3 for gas and $/bbl for oil) for gas and oil wells were taken directly from a technical background document for Alberta's royalty review (see Alberta Department of Energy 2007a). Operating costs vary from well to well and region to region. Operating costs by PSAC region are shown in Table 6 for oil and gas.

Table 6. Operating costs used in NPV model for gas and oil wells.

| PSAC Region | Variable Operating Cost Gas Well $/m3 | Variable Operating Cost Oil Wells $/bbl |
|---|---|---|
| 1 | 20.83 | 6.60 |
| 2 | 18.00 | 6.60 |
| 3 | 11.30 | 4.79 |
| 4 | 13.77 | 5.93 |
| 5 | 13.06 | 4.66 |
| 6 | 13.06 | 4.66 |
| 7 | 14.47 | 4.81 |

*Costs taken from Alberta Department of Energy (2007a)

*Equipment and Tie In Costs*

Equipment costs per well ($C_{equip}$) for oil and gas wells and tie-in costs per well ($C_{TieIn}$) for gas wells were taken directly from a technical background document for Alberta's royalty review (see Alberta Department of Energy 2007a). Equipment costs vary from well to well and region to region. Equipment costs and Tie-In costs by PSAC region are shown in Table 7 for oil and gas.

Table 7. Equipment and Tie-in costs for gas and oil wells.

| | Gas Wells | | Oil Wells |
|---|---|---|---|
| PSAC Region | Equipment Cost $/well | Tie-In Cost $/well | Equipment Cost $/well |
| 1 | 236,000 | 432,000 | 55,000 |
| 2 | 123,000 | 278,000 | 55,000 |
| 3 | 39,000 | 53,000 | 57,000 |
| 4 | 29,000 | 67,000 | 56,000 |
| 5 | 42,000 | 82,000 | 57,000 |
| 6 | 80,000 | 120,000 | 57,000 |
| 7 | 118,000 | 324,000 | 57,000 |

*Costs taken from Alberta Department of Energy (2007a)

*Seismic Costs*

Seismic costs per well ($C_{seismic}$) for oil and gas wells were also taken directly from a technical background document for Alberta's royalty review (see Alberta Department of Energy 2007a). Seismic costs are pre-well exploration costs. However, seismic costs are often reported on a per-well basis. Hence, in our model seismic costs per well as reported in Table 8, were computed on a tract basis by multiplying by the expected number of wells for the tract. See the section, entitled *Number of Wells per Tract* for details on the expected number of wells.

Table 8. Seismic Costs

| PSAC Region | Ave. Seismic Costs $/well |
|---|---|
| 1 | 212,000 |
| 2 | 20,000 |
| 3 | 9,000 |
| 4 | 5,000 |
| 5 | 17,000 |
| 6 | 10,000 |
| 7 | 36,000 |

*Costs taken from Alberta Department of Energy (2007a)

*Price Forecasts*

Price forecasts $P_{gt}$ for (g=) methane were obtained from GLJ Petroleum Consultants for October 1, 2009 (see Herchen 2009). We used the Alberta Reference Price forecast. The reference price is a weighted average field price based on field sales in Alberta and is developed by the Alberta Department of Energy. The Alberta government uses the reference prices for royalty calculations.

The price forecasts provided are in current dollars. The prices were deflated to $2008 using the consumer price index. The forecasts provided in Herchen (2009) go up to 2018. In our forecast, all prices after 2018 were set equal to the price in 2008. Past prices and a forecast for methane gas is shown in Figure 9.

Prices in the Herchen (2009) are reported in $/mmbtu, which were converted to $/GJ by dividing by a factor of 1.055. However, our $/GJ prices needed to be converted to $/1000m3 because gas volume flow profiles are in 1000m3. Table 9 shows the energy content in GJ/1000m3 for each component gas. In addition, there are differences in prices for each of the component gases. We used price ratios to adjust the prices for methane shown in Figure 9. The price ratios were developed from monthly time series of reference prices for methane, ethane, propane, butane and Pentane Plus for Jan 2007 to September 2008, which were obtained from Alberta Department of Energy (2007c, 2008b) Gas Royalty Calculation Information Bulletins. Ratios were computed by taking the price ratios of ethane, propane, butane and pentane to methane for each month of the time series and then computing an average. The average price ratios are in the 3rd column of Table 9. The price of each component gas $P_g$ were then computed as follows:

$$P_{methane} = P^R_{methane} \times E_{methane}$$
$$P_g = r^m_g \times P^R_{methane} \times E_g$$ for $g$=ethane, propane, butane and pentane,

where $P^R_{methane}$ is the reference price for methane in \$/GJ as shown in Figure 9, and where $r^m_g$ is gas to methane price ratio, and $E_g$ is energy content of component gas found in Table 9. For the purposes of computing royalties the reference prices are needed for ethane, propane, butane and pentanes. These are easily computed using:

$P^R_g = r^m_g \times P^R_{methane}$ for $g$=ethane, propane, butane and pentane.

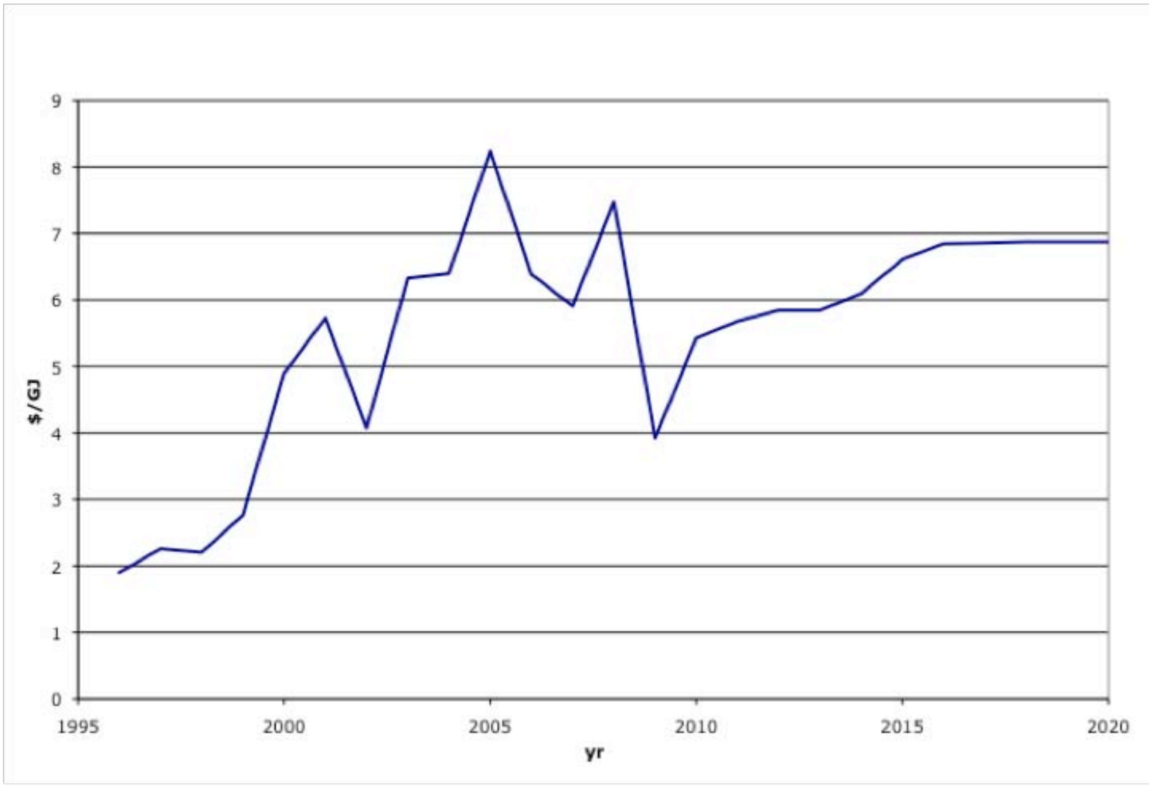



Figure 9. Alberta reference prices, past and forecasted from 2009-2020.

Table 9. Energy content and Energy Content with Price Adjustment for component gases.

| Component Gas | Energy Content GJ/1000m3 | Component to Methane price ratio |
|---|---|---|
| Methane | 37 | 1 |
| Ethane | 66.065 | 1.0484 |
| Propane | 93.936 | 1.0597 |
| Butane | 121.6 | 1.0638 |
| Pentane Plus | 149.15 | 1.0666 |

*Royalties*

Royalties were computed using Alberta's post royalty-review system. However, the computations were simplified and excluded some of the special rates such as those applying to transitions wells and incentive programs such as the deep gas drilling program. Some of these rates will be added in the future versions of the model. This document shows how royalties were calculated for the current state of our model and relies heavily on Alberta Department of Energy (2008). Royalties for gas are collected as percentage of the par price set for each gas component by the government of Alberta. In addition, there are different rates for the gas components, which include methane, ethane, butane, propane, and pentanes. Total royalties over a month could then be computed as

$$\text{Total Royalty} = \sum_{g}^{G} v_{gt} C_{gt}^{Roy} = \sum_{g}^{G} v_{gt} P_{gt}^{R} R_{gt}^{\%}$$

where $R_{gt}^{\%}$ is the royalty rate for component $g$ and $C_{gt}^{Roy}$, $P_{gt}^{R}$, and $v_{gt}$ are the royalties for year $t$, the reference price of gas and the volume flow per year for gas component $g$ in m3 as defined in equation 1 (see NPV formula). While royalties are charged on a monthly basis in Alberta our formula averages prices and volumes flows over a year to reduce the number of computations.

In the following paragraphs, we focus on the computation of the royalty rate or $R_g^{\%}$. The following discussion is based on Alberta Department of Energy (2008). The royalty rate $R_g^{\%}$ is based on two components: the price component which makes $R_g^{\%}$ price responsive and the quantity component which makes $R_g^{\%}$ responsive to the amount of gas the well is producing. The formula is:

$$R_g^{\%} = \begin{cases} 0.05 & \text{if } r_{gp} + r_g < 0.05 \\ r_{gp} + r_g & \text{if } 0.05 \le r_{gp} + r_g \le 0.5 \\ 0.05 & \text{if } r_{gp} + r_g > 0.5 \end{cases} \quad \text{for } g = \text{methane, ethane}$$

$$R_g^{\%} = 0.3 \qquad \text{for } g = \text{butane, propane}$$

$$R_g^{\%} = 0.4$$

where $r_{gp}$ is the price component for gas type $g$ and $r_q$ is the quantity component, common to all types of gas. Note, that the rate has a maximum of 0.5 and a minimum of 0.05. This rate is computed for each of the gas components.

The price part $r_{gp}$ is computed by the following formula:

$$
r_{gp} = \begin{cases} \left(P_g^R - 4.5\right) \times 4.5 \quad \text{if } P_g^R \le 7 \\ \left(P_g^R - 7\right) \times 3 + 11.25 \quad \text{if } 7 \le P_g^R \le 11 \\ \left(P_g^R - 11\right) \times 1 + 23.25 \quad \text{if } 11 \le P_g^R \le 17.75 \\ 30 \quad \text{if } 17.75 \le P_g^R \end{cases}
$$

where $P_g^R$ is the reference price of gas for gas component *g*, set by the government of Alberta on a monthly basis. The reference price is set based on a formula whereby various allowances are subtracted from the average price of gas in Alberta. These include allowances for marketing, transportation of gas within Alberta, pipeline fuel/loss factors and other special allowances. The allowances typically amount to a few cents per GJ of gas and make up a small percentage of the average gas price in Alberta. More information on the setting of the par prices may be seen in the monthly information bulletins put out by Alberta Energy (e.g. Alberta Energy 2008). Thus the reference price for gas is tightly linked to average gas prices in Alberta and the price component in the royalty formula will increase when gas prices increase and decrease when gas price decrease. The price component can become negative when the reference price falls below \$4.5/GJ and can go to a maximum 30% when the reference price increases above \$17.75/GJ.

While the price part varies by component gas, the quantity part is common to all gas components. The quantity component is dependent on the overall production of gas 1000s of m3 per day. The larger the daily production of gas the larger the quantity component. The quantity component is modified by a depth factor that increases with depth. The higher the depth factor the lower the quantity component. The quantity component is computed as follows:

$$
q_p = \begin{cases} \left(v_t^d - 4D^f\right) 0.05 / D^f \quad \text{if } v_t^d \le 6D^f \\ \left(v_t^d - 6D^f\right)\left(0.03/D^f + 0.1\right) \quad \text{if } 6D^f < v_t^d \le 11D^f \\ \left(v_t^d - 11D^f\right)\left(0.01/D^f + 0.25\right) \quad \text{if } v_t^d > 11D^f \\ 0.3 \quad \text{if } \left(v_t^d - 11D^f\right)\left(0.01/D^f - 0.25\right) > 0.3 \end{cases}
$$

Where $D^f$ is the depth factor ($1 \le D^f \le 4$) and $v_t^d$ is the daily production in year *t*. The daily production is computed based on the yearly production curves described in a previous section:

$$
v_t^d = \frac{v_t}{365} A^{gf}
$$

where $v_t$ the total flow of gas over the year is divided by 365 days and multiplied by an addition factor $A^{gf}$, which is the acid gas factor. The acid gas factor is multiplicative and equals one if the acid gases, hydrogen sulphide and carbon dioxide are negligible (i.e. less than 3% of the total flow of gas). The full formula for the acid gas factor is

$$A^{gf} = \begin{cases} 1.0 \text{ if } CO_2\% + H_2S\% \leq 3 \\ 1.03 - \left(CO_2\% + H_2S\%\right) \quad \text{if } \ 3 < CO_2\% + H_2S\% < 25 \\ 0.78 \text{ if } CO_2\% + H_2S\% \geq 25 \end{cases}$$

In addition, we have the following identity that relates gas components to total production: $v_t = \sum_g^G v_{gt}$. The quantity component has a maximum of 0.3 and may also be negative if the daily production is less than 4 times the depth factor. The depth factor is computed as follows:

$$D^f = \begin{cases} 1 \text{ if } MD < 2000m \\ \left(MD/2000\right)^2 \text{ if } \ 2000m \leq MD \leq 4000m \\ 4 \quad \text{if } MD > 4000m \end{cases}$$

where MD is the measured depth of the well as defined above.

Natural gas was split up into its components methane, ethane, butane, propane, and pentane plus using the table provided in Alberta Department of Energy (2007a). The table gives proportions of component gases as compared to the total volume of gas by PSAC region and the volume over time profiles discussed above. Component gas volumes ($v_{gt}$) were then computed using:

$$v_{gt} = \rho_g v_t$$

where $\rho_g$ is the proportion of component gas $g$ found in the total volume stream $v_t$. The proportion $\rho_g$, for each component gas, can be found in Table 10 for 6 sizes of gas well in each of the 7 PSAC regions of Alberta. The table also shows proportions for helium, nitrogen, carbon dioxide and hydrogen sulphide, which we ignore in our NPV model.

Table 10. The proportion of total gas flow made up of individual component gases for a range of well sizes in each PSAC region. Source: Alberta Department of Energy (2007b).

| PSAC | Curve# | Gas Tot. m3 | He (Helium) | N2 (Nitrogen) | CO2 | H2S | C1 (methane) | C2 (Ethane) | C3 (propane) | C4 (Butane) | C5+ (Pentane) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 21,804 | 0.0003 | 0.0095 | 0.0279 | 0.0335 | 0.8335 | 0.0562 | 0.0218 | 0.0093 | 0.0080 |
| 1 | 2 | 26,957 | 0.0003 | 0.0095 | 0.0279 | 0.0335 | 0.8335 | 0.0562 | 0.0218 | 0.0093 | 0.0080 |
| 1 | 3 | 129,407 | 0.0002 | 0.0067 | 0.0342 | 0.0419 | 0.8462 | 0.0440 | 0.0143 | 0.0059 | 0.0066 |
| 1 | 4 | 135,013 | 0.0002 | 0.0067 | 0.0342 | 0.0419 | 0.8462 | 0.0440 | 0.0143 | 0.0059 | 0.0066 |
| 1 | 5 | 462,976 | 0.0001 | 0.0040 | 0.0367 | 0.0354 | 0.8559 | 0.0434 | 0.0131 | 0.0055 | 0.0059 |
| 1 | 6 | 477,276 | 0.0001 | 0.0040 | 0.0367 | 0.0354 | 0.8559 | 0.0434 | 0.0131 | 0.0055 | 0.0059 |
| 2 | 1 | 5,125 | 0.0007 | 0.0137 | 0.0188 | 0.0050 | 0.8418 | 0.0674 | 0.0301 | 0.0126 | 0.0099 |
| 2 | 2 | 7,532 | 0.0007 | 0.0137 | 0.0188 | 0.0050 | 0.8418 | 0.0674 | 0.0301 | 0.0126 | 0.0099 |
| 2 | 3 | 30,101 | 0.0006 | 0.0124 | 0.0177 | 0.0035 | 0.8391 | 0.0716 | 0.0318 | 0.0134 | 0.0099 |
| 2 | 4 | 34,320 | 0.0006 | 0.0124 | 0.0177 | 0.0035 | 0.8391 | 0.0716 | 0.0318 | 0.0134 | 0.0099 |
| 2 | 5 | 144,924 | 0.0004 | 0.0102 | 0.0220 | 0.0174 | 0.8349 | 0.0653 | 0.0277 | 0.0117 | 0.0104 |
| 2 | 6 | 152,003 | 0.0004 | 0.0102 | 0.0220 | 0.0174 | 0.8349 | 0.0653 | 0.0277 | 0.0117 | 0.0104 |
| 3 | 1 | 1,133 | 0.0013 | 0.0317 | 0.0025 | 0.0003 | 0.9567 | 0.0052 | 0.0014 | 0.0006 | 0.0003 |
| 3 | 2 | 2,464 | 0.0013 | 0.0317 | 0.0025 | 0.0003 | 0.9567 | 0.0052 | 0.0014 | 0.0006 | 0.0003 |
| 3 | 3 | 3,681 | 0.0013 | 0.0318 | 0.0020 | 0.0001 | 0.9578 | 0.0048 | 0.0013 | 0.0006 | 0.0003 |
| 3 | 4 | 4,814 | 0.0013 | 0.0318 | 0.0020 | 0.0001 | 0.9578 | 0.0048 | 0.0013 | 0.0006 | 0.0003 |
| 3 | 5 | 12,091 | 0.0013 | 0.0332 | 0.0038 | 0.0003 | 0.9361 | 0.0148 | 0.0058 | 0.0026 | 0.0021 |
| 3 | 6 | 14,895 | 0.0013 | 0.0332 | 0.0038 | 0.0003 | 0.9361 | 0.0148 | 0.0058 | 0.0026 | 0.0021 |
| 4 | 1 | 1,133 | 0.0007 | 0.0380 | 0.0019 | 0.0000 | 0.9367 | 0.0149 | 0.0044 | 0.0022 | 0.0012 |
| 4 | 2 | 3,002 | 0.0007 | 0.0380 | 0.0019 | 0.0000 | 0.9367 | 0.0149 | 0.0044 | 0.0022 | 0.0012 |
| 4 | 3 | 6,541 | 0.0007 | 0.0386 | 0.0021 | 0.0000 | 0.9354 | 0.0167 | 0.0038 | 0.0016 | 0.0011 |
| 4 | 4 | 9,401 | 0.0007 | 0.0386 | 0.0021 | 0.0000 | 0.9354 | 0.0167 | 0.0038 | 0.0016 | 0.0011 |
| 4 | 5 | 33,782 | 0.0008 | 0.0383 | 0.0022 | 0.0000 | 0.9372 | 0.0160 | 0.0033 | 0.0014 | 0.0008 |
| 4 | 6 | 37,576 | 0.0008 | 0.0383 | 0.0022 | 0.0000 | 0.9372 | 0.0160 | 0.0033 | 0.0014 | 0.0008 |
| 5 | 1 | 2,152 | 0.0006 | 0.0228 | 0.0085 | 0.0005 | 0.9254 | 0.0251 | 0.0096 | 0.0046 | 0.0029 |
| 5 | 2 | 4,332 | 0.0006 | 0.0228 | 0.0085 | 0.0005 | 0.9254 | 0.0251 | 0.0096 | 0.0046 | 0.0029 |
| 5 | 3 | 10,590 | 0.0006 | 0.0227 | 0.0086 | 0.0006 | 0.9288 | 0.0233 | 0.0087 | 0.0041 | 0.0026 |
| 5 | 4 | 13,620 | 0.0006 | 0.0227 | 0.0086 | 0.0006 | 0.9288 | 0.0233 | 0.0087 | 0.0041 | 0.0026 |
| 5 | 5 | 50,913 | 0.0006 | 0.0232 | 0.0123 | 0.0008 | 0.8961 | 0.0391 | 0.0154 | 0.0077 | 0.0048 |
| 5 | 6 | 55,444 | 0.0006 | 0.0232 | 0.0123 | 0.0008 | 0.8961 | 0.0391 | 0.0154 | 0.0077 | 0.0048 |
| 6 | 1 | 2,464 | 0.0003 | 0.0125 | 0.0079 | 0.0000 | 0.9741 | 0.0042 | 0.0005 | 0.0001 | 0.0004 |
| 6 | 2 | 4,757 | 0.0003 | 0.0125 | 0.0079 | 0.0000 | 0.9741 | 0.0042 | 0.0005 | 0.0001 | 0.0004 |
| 6 | 3 | 15,404 | 0.0003 | 0.0112 | 0.0097 | 0.0000 | 0.9762 | 0.0019 | 0.0003 | 0.0001 | 0.0003 |
| 6 | 4 | 19,397 | 0.0003 | 0.0112 | 0.0097 | 0.0000 | 0.9762 | 0.0019 | 0.0003 | 0.0001 | 0.0003 |
| 6 | 5 | 62,750 | 0.0002 | 0.0104 | 0.0107 | 0.0000 | 0.9699 | 0.0076 | 0.0005 | 0.0002 | 0.0005 |
| 6 | 6 | 65,638 | 0.0002 | 0.0104 | 0.0107 | 0.0000 | 0.9699 | 0.0076 | 0.0005 | 0.0002 | 0.0005 |
| 7 | 1 | 3,681 | 0.0006 | 0.0137 | 0.0212 | 0.0105 | 0.9106 | 0.0243 | 0.0099 | 0.0048 | 0.0044 |
| 7 | 2 | 8,099 | 0.0006 | 0.0137 | 0.0212 | 0.0105 | 0.9106 | 0.0243 | 0.0099 | 0.0048 | 0.0044 |
| 7 | 3 | 13,903 | 0.0006 | 0.0137 | 0.0212 | 0.0105 | 0.9106 | 0.0243 | 0.0099 | 0.0048 | 0.0044 |
| 7 | 4 | 21,492 | 0.0006 | 0.0137 | 0.0212 | 0.0105 | 0.9106 | 0.0243 | 0.0099 | 0.0048 | 0.0044 |
| 7 | 5 | 78,437 | 0.0006 | 0.0137 | 0.0212 | 0.0105 | 0.9106 | 0.0243 | 0.0099 | 0.0048 | 0.0044 |
| 7 | 6 | 93,671 | 0.0006 | 0.0137 | 0.0212 | 0.0105 | 0.9106 | 0.0243 | 0.0099 | 0.0048 | 0.0044 |

*Taxes*

Firms in the natural gas industry pay corporate taxes to both federal and provincial governments. Corporate tax rates are subject to change over time. In this study we chose rates that closely approximate current conditions and use the same rates used by the Alberta Department of Energy in 2007 royalty review reports (see Alberta Department of Energy 2007a). Thus, the provincial corporate tax rate was set at 10% and the federal rate was set at 20%. Taxes are computed at the corporate level. This posed a problem for our simple model, which does not contain corporate entities. Thus taxes had to be computed at the well level, since that is the activity we are modeling. Taxes, for each year of a well's life, were computed by multiplying the percentage rates times the net revenue allowing for all operating costs, royalties, an allowance for depreciation of the initial capital investment. Depreciation was estimated in each year by applying a depreciation rate of 20%.

$$T_t^{ax} = 0.3\left(\sum_g^G v_{gt}\left(P_{gt} - C^{oper} - C_{gt}^{Roy}\right) - \delta K_t\right)$$

where $K_t$ is the capital balance in real dollars at the beginning of period $t$ and δ is the depreciation rate. The capital balance is updated each year of he well's life using the formula:

$$K_t = K_{t-1}(1-\delta)$$

Conceivably, the formula could yield a negative result. In that case the tax for that year was simply set to zero.

*Probability of Successful Drilling*

The variables $p^{success}$ and $p^{seis}$ capture the uncertain nature of oil and gas exploration and discovery. They are used to model firms' expectations about the probability of discovery of future reserves on undrilled sections. The success rates ($p^{success}$) are based on an analysis of GeoScout well data while $p^{seis}$ is derived . Drilling success rates or probabilities of success may be expressed in different ways. A common way of expressing this is the number of successful wells drilled divided by the total number of drilled wells over a play area. Success is defined as a well that produces gas. However, this way of expressing success rate did not quite fit with our study. In the section that describes the ultimate potential data for natural gas we defined a tract, which is a combination of land section and stratigraphic interval, as our basic unit of exploitation and exploration. This influenced our choice of definition for success rate in our model. Our success rate is defined as the probability that at least one successful well will be drilled into a tract. We estimate the success probabilities over each play area in each stratigraphic interval using the following formula:

$$p^{success} = \frac{\text{Number of Successfully Drilled Sections}}{\text{Total Number of Sections Drilled}}$$

Data for drilled sections and successfully drilled sections was obtained from data downloaded from GeoScout. Each well was linked to a stratigraphic interval and play as outlined in the previous section on attaching wells to stratigraphic intervals. Wells were then classified as successful or not successful. Successful wells are wells that had either produced gas or that were classed as drilled and cased. Each tract, which is a specific land section/stratigraphic ID/play combination, was classified as successfully drilled if at least one well was classified as successful on the tract. The results of these computations are show in Table 11.

The table also shows the success rates provided by the EUB/NEB (2005) study for three scenarios that reflect low, medium, and high expectations of the probability of finding additional gas resources on a tract level. Note, that the probabilities provided by EUB/NEB (2005) for even the high scenario are considerably lower than the probabilities computed from the data downloaded from GeoScout. While, the EUB/NEB study gives the name drilling success rates to these success rates, they clearly have been computed using much different methods. Preliminary NPV models that used the EUB/NEB success rates instead of those computed from GeoScout, yielded NPVs that were consistently negative which was not a reasonable outcome given the amount of gas exploration happening in Alberta. These success rates are also much lower than those found in other sources such as Alberta Department of Energy (2007a). Hence, a different interpretation of the success rates incorporated in the EUB/NEB study is required. Rather than drilling success, we interpret the EUB/NEB rates as probabilities that a tract has gas resources before seismic or other testing has taken place (We interpret our drilling success rates as being conditional on some preliminary testing such as seismic. See explanation below.). The EUB/NEB rates can also be interpreted as the expected proportion of all remaining future tracts that will have gas resources. This interpretation is consistent with the way ultimate potential is calculated in the EUB/NEB ultimate potential study for future resources. While EUB/NEB does not provide a formula in it's written documentation, they do provide a spreadsheet that shows how ultimate potential for natural gas is computed for booked, unbooked, unconfirmed, bypassed and future resources. The formula for total future (i.e. undiscovered) gas resources in Alberta may be expressed as follows:

$$\textit{Total Future Potential} = \sum_{s=1}^{42} \sum_{m=1}^{M_s} p_{sm}^{EUB} V_{sm} N_{sm}^{f}$$

where $s$ is a stratigraphic interval from 1 to 42, $M_s$ is the number of plays in stratigraphic interval $s$, $m$ denotes a specific play, $N^f$ is the number of future tracts in stratigraphic interval $s$ play area $m$ left unexplored, $p^{EUB}$ is the probability that an unexplored tract has gas resources and $V_{sm}$ is the median volume of gas found previously in play $m$ of stratigraphic interval $m$.

The formula also illustrates why we cannot simply replace the EUB probabilities with drilling probabilities. Doing so would increase the estimate of future potential, since $p^{success} > p^{EUB}$ in most cases, and we wished to honour the EUB's estimates of ultimate potential. We assume that the differences between the EUB success rates from the ultimate potential database and those we computed from the data exported from GeoScout is due to the different stages of information acquisition that takes place over the different stages of the exploration process, from the initial geological assessments, through seismic to drilling. Exploration companies do not drill everywhere, they only drill when the signals from pre-drilling activity such as assessments of geology and seismic activity indicate that the risk of drilling is reduced and worth undertaking. Thus drilling success rates acquired through the GeoScout data are considered to be post seismic and/or other geological assessment, while those in the ultimate potential data are pre-seismic because they reflect the estimated proportion of sections within a play that resource will be found. Hence, the outcome of the initial exploration activity is an indicator that says drill or don't drill. In order to use both our success rates and the EUB/NEB rates we then had to assume that not all tracts would be drilled, and that the $p^{success}$ rates we computed from the data downloaded from GeoScout were conditional on additional positive assessments of geology such as seismic happen at the predrilling phase of exploration. Hence, a new probability $p^{sies}$ was computed by reconciling success rates found in the ERCB ultimate potential database with those found in the GeoScout analysis. In our model $p^{seis}$ is interpreted as the probability that pre-drilling exploration activity including seismic activity indicates there are resources in a section and that it might be profitable to drill in a section. To compute $p^{seis}$ we use the following formula:

$$p_{sm}^{seis} \times p_{sm}^{success} = p_{sm}^{EUB}$$

where $p^{EUB}$ is the success rate found in ERCB's ultimate potential database for strata *s* and play *m* (see table 11). The probability $p^{seis}$ can be determined by dividing through by $p^{success}$. This approach also ensures that assessments of NPV and aggregate volumes obtained in our model will match the ultimate potential estimates of ERCB on both an aggregate and spatial/regional level.

Table 11. Drilling success rates and probabilities that tracts have future resources.

| Strat Inter -val | Play ID | Median # wells per tract | Success rate per tract | Proportion of Wells Successful given successful tract | Probability that a tract has future resources for three scenarios (From EUB/NEB). | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Future tracts | | | Unconfirmed tracts | | | Bypassed tracts | | |
| | | | | | Low | Med. | High | Low | Med. | High | Low | Med. | High |
| 1 | 1 | 1 | 0.91 | 0.99 | 0.04 | 0.06 | 0.1 | 0.20 | 0.4 | 0.8 | 0.05 | 0.1 | 0.2 |
| 1 | 2 | 1 | 0.69 | 0.97 | 0.01 | 0.02 | 0.04 | 0.20 | 0.4 | 0.8 | 0.05 | 0.1 | 0.2 |
| 1 | 3 | 1 | 0.42 | 1.00 | 0.05 | 0.07 | 0.1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 1 | 10 | 1 | 0.00 | 1.00 | 0 | 0.02 | 0.04 | 0.20 | 0.4 | 0.8 | 0.05 | 0.1 | 0.2 |
| 2 | 1 | 1 | 0.64 | 1.00 | 0.02 | 0.03 | 0.04 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 2 | 2 | 1 | 0.72 | 0.94 | 0.07 | 0.08 | 0.15 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 2 | 3 | 1 | 0.67 | 0.98 | 0.005 | 0.01 | 0.015 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 2 | 4 | 1 | 0.79 | 0.96 | 0.1 | 0.11 | 0.15 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 2 | 10 | 1 | 0.08 | 1.00 | 0 | 0.01 | 0.015 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 3 | 1 | 1 | 0.90 | 0.98 | 0.1 | 0.15 | 0.2 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 3 | 10 | 1 | 0.00 | 0.98 | 0 | 0.15 | 0.2 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 4 | 1 | 1 | 0.50 | 0.75 | 0.2 | 0.3 | 0.4 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 4 | 2 | 1 | 1.00 | 1.00 | 1 | 1 | 1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 4 | 3 | 1 | 0.71 | 0.98 | 0.25 | 0.5 | 0.75 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 4 | 4 | 1 | 0.69 | 0.99 | 0.15 | 0.25 | 0.4 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 4 | 10 | 1 | 0.34 | 0.82 | 0 | 0.25 | 0.4 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 5 | 1 | 1 | 0.97 | 0.99 | 1 | 1 | 1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 5 | 2 | 1 | 0.81 | 0.99 | 0.05 | 0.1 | 0.15 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 5 | 3 | 1 | 0.86 | 0.99 | 0.07 | 0.08 | 0.1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 6 | 1 | 1 | 0.99 | 1.00 | 0.4 | 0.5 | 0.6 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 6 | 2 | 1 | 0.56 | 1.00 | 0.01 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 6 | 10 | 1 | 0.05 | 1.00 | 0 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 7 | 1 | 1 | 1.00 | 1.00 | 0.07 | 0.08 | 0.1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 7 | 2 | 1 | 1.00 | 1.00 | 0.1 | 0.15 | 0.25 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 7 | 3 | 1 | 0.96 | 1.00 | 0.001 | 0.0025 | 0.005 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 7 | 10 | 1 | 0.00 | 1.00 | 0 | 0.0025 | 0.005 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 8 | 1 | 1 | 0.68 | 0.93 | 0.01 | 0.015 | 0.02 | 0.10 | 0.15 | 0.2 | 0 | 0.05 | 0.1 |
| 8 | 2 | 1 | 0.89 | 0.96 | 0.03 | 0.04 | 0.05 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 8 | 3 | 1 | 0.68 | 0.96 | 0.1 | 0.15 | 0.2 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 8 | 4 | 1 | 0.44 | 0.99 | 0.004 | 0.005 | 0.006 | 0.05 | 0.1 | 0.15 | 0.05 | 0.1 | 0.15 |
| 8 | 10 | 1 | 0.00 | 0.99 | 0 | 0.005 | 0.006 | 0.10 | 0.15 | 0.2 | 0 | 0.05 | 0.1 |
| 9 | 1 | 1 | 0.89 | 0.93 | 0.01 | 0.02 | 0.03 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 9 | 2 | 1 | 0.82 | 1.00 | 0.005 | 0.006 | 0.007 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 10 | 1 | 1 | 0.83 | 0.99 | 0.07 | 0.08 | 0.1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 10 | 2 | 1 | 0.69 | 0.93 | 0.05 | 0.06 | 0.07 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 10 | 10 | 1 | 0.00 | 0.93 | 0 | 0.06 | 0.07 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 11 | 1 | 1 | 0.83 | 0.99 | 0.005 | 0.01 | 0.015 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 11 | 2 | 1 | 0.68 | 1.00 | 0.003 | 0.004 | 0.005 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 11 | 3 | 1 | 0.93 | 0.99 | 0.35 | 0.4 | 0.45 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 11 | 10 | 1 | 0.17 | 1.00 | 0 | 0.004 | 0.005 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 12 | 1 | 1 | 0.93 | 0.99 | 0.04 | 0.05 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 12 | 2 | 1 | 0.86 | 1.00 | 0.04 | 0.05 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 12 | 3 | 1 | 0.62 | 0.99 | 0.01 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0 | 0.05 | 0.1 |
| 12 | 10 | 1 | 0.02 | 1.00 | 0 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |

| Strat Inter -val | Play ID | Median # wells per tract | Success rate per tract | Proportion of Wells Successful given successful tract | Probability that a tract has future resources for three scenarios (From EUB/NEB) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Future tracts | | | Unconfirmed tracts | | | Bypassed tracts | | |
| | | | | | Low | Med. | High | Low | Med. | High | Low | Med. | High |
| 13 | 1 | 1 | 0.83 | 0.94 | 0.15 | 0.2 | 0.3 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 13 | 2 | 1 | 0.80 | 0.99 | 0.1 | 0.12 | 0.16 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 13 | 3 | 1 | 0.88 | 0.97 | 0.02 | 0.04 | 0.08 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 13 | 4 | 1 | 0.93 | 0.99 | 0.1 | 0.12 | 0.14 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 13 | 5 | 1 | 0.91 | 0.99 | 0.04 | 0.05 | 0.08 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 13 | 6 | 1 | 0.82 | 0.99 | 0.08 | 0.09 | 0.12 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 13 | 10 | 1 | 0.00 | 0.99 | 0 | 0.04 | 0.08 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 14 | 1 | 1 | 0.93 | 0.98 | 0.03 | 0.04 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 14 | 10 | 1 | 0.00 | 0.98 | 0 | 0.04 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 15 | 1 | 1 | 0.68 | 1.00 | 0.18 | 0.2 | 0.22 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 15 | 2 | 1 | 0.54 | 0.94 | 0.06 | 0.075 | 0.09 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 15 | 3 | 1 | 0.75 | 0.94 | 0.2 | 0.28 | 0.38 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 15 | 4 | 1 | 0.62 | 0.96 | 0.2 | 0.25 | 0.3 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 15 | 10 | 1 | 0.02 | 1.00 | 0 | 0.075 | 0.09 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 16 | 1 | 1 | 0.84 | 0.99 | 0.12 | 0.14 | 0.17 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 16 | 2 | 1 | 0.87 | 0.99 | 0.04 | 0.06 | 0.09 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 16 | 3 | 1 | 0.72 | 0.99 | 0.03 | 0.04 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 16 | 4 | 1 | 0.95 | 0.99 | 0.2 | 0.3 | 0.4 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 16 | 10 | 1 | 0.00 | 0.99 | 0 | 0.04 | 0.06 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 17 | 1 | 1 | 0.84 | 1.00 | 0.025 | 0.03 | 0.035 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 17 | 10 | 1 | 0.00 | 1.00 | 0 | 0.03 | 0.035 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 18 | 1 | 1 | 0.75 | 0.97 | 0.08 | 0.12 | 0.18 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 18 | 2 | 1 | 0.37 | 0.95 | 0.06 | 0.08 | 0.1 | 0.15 | 0.3 | 0.45 | 0 | 0.05 | 0.1 |
| 18 | 10 | 1 | 0.01 | 1.00 | 0 | 0.08 | 0.1 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 19 | 1 | 1 | 0.78 | 1.00 | 0.01 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 19 | 2 | 1 | 0.50 | 0.99 | 0.08 | 0.1 | 0.12 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 19 | 3 | 1 | 0.88 | 0.98 | 0.15 | 0.2 | 0.3 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 19 | 10 | 1 | 0.00 | 0.98 | 0 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 20 | 1 | 1 | 0.49 | 0.88 | 0.03 | 0.05 | 0.07 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 20 | 2 | 1 | 0.37 | 0.96 | 0.01 | 0.02 | 0.03 | 0.05 | 0.1 | 0.15 | 0 | 0.05 | 0.1 |
| 20 | 3 | 1 | 0.16 | 0.97 | 0.01 | 0.02 | 0.04 | 0.05 | 0.1 | 0.15 | 0 | 0.05 | 0.1 |
| 20 | 10 | 1 | 0.01 | 1.00 | 0 | 0.02 | 0.03 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 21 | 1 | 1 | 0.12 | 0.89 | 0.01 | 0.03 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 21 | 2 | 1 | 0.48 | 0.75 | 0.08 | 0.1 | 0.15 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 21 | 3 | 1 | 0.16 | 0.89 | 0.01 | 0.02 | 0.03 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 21 | 4 | 1 | 0.68 | 0.98 | 0.14 | 0.18 | 0.25 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 21 | 5 | 1 | 0.25 | 1.00 | 0.0045 | 0.005 | 0.0055 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 21 | 10 | 1 | 0.00 | 1.00 | 0 | 0.005 | 0.0055 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 22 | 1 | 1 | 0.83 | 1.00 | 0.003 | 0.005 | 0.008 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 22 | 2 | 1 | 0.72 | 0.97 | 0.07 | 0.1 | 0.14 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 22 | 3 | 1 | 0.35 | 0.97 | 0.008 | 0.01 | 0.012 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 22 | 4 | 1 | 0.55 | 0.99 | 0.003 | 0.004 | 0.005 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 22 | 10 | 1 | 0.10 | 1.00 | 0 | 0.004 | 0.005 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 23 | 1 | 1 | 0.85 | 0.99 | 0.09 | 0.12 | 0.15 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 24 | 1 | 1 | 0.67 | 0.86 | 0.02 | 0.03 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |

| Strat Inter -val | Play ID | Median # wells per tract | Success rate per tract | Proportion of Wells Successful given successful tract | Probability that a tract has future resources for three scenarios (From EUB/NEB) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Future tracts | | | Unconfirmed tracts | | | Bypassed tracts | | |
| | | | | | Low | Med. | High | Low | Med. | High | Low | Med. | High |
| 24 | 2 | 1 | 0.80 | 0.96 | 0.06 | 0.08 | 0.12 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 24 | 10 | 1 | 0.00 | 0.96 | 0 | 0.03 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 25 | 1 | 1 | 0.74 | 0.93 | 0.03 | 0.05 | 0.08 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 25 | 10 | 1 | 0.00 | 0.93 | 0 | 0.05 | 0.08 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 26 | 1 | 1 | 0.90 | 0.97 | 0 | 0.07 | 0.13 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 26 | 2 | 1 | 0.90 | 0.97 | 0.12 | 0.14 | 0.2 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 26 | 10 | 1 | 0.36 | 1.00 | 0 | 0.07 | 0.13 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 27 | 1 | 1 | 1.00 | 1.00 | 0 | 0.2 | 0.4 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 27 | 2 | 1 | 0.31 | 0.95 | 0.01 | 0.02 | 0.03 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 27 | 10 | 1 | 0.05 | 1.00 | 0 | 0.02 | 0.03 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 28 | 1 | 1 | 0.69 | 1.00 | 0.01 | 0.03 | 0.05 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 28 | 2 | 1 | 0.41 | 0.95 | 0.04 | 0.06 | 0.1 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 28 | 10 | 1 | 0.10 | 1.00 | 0 | 0.03 | 0.05 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 29 | 1 | 1 | 0.80 | 1.00 | 0.01 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 29 | 2 | 1 | 0.27 | 0.97 | 0.01 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 29 | 10 | 1 | 0.00 | 0.97 | 0 | 0.015 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 30 | 1 | 1 | 0.74 | 0.97 | 0.02 | 0.03 | 0.05 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 30 | 10 | 1 | 0.00 | 0.97 | 0 | 0.03 | 0.05 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 31 | 1 | 1 | 0.78 | 0.89 | 0.015 | 0.025 | 0.06 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 31 | 2 | 1 | 0.05 | 0.77 | 0.015 | 0.025 | 0.045 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 31 | 3 | 1 | 0.52 | 0.95 | 0.05 | 0.07 | 0.12 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 31 | 4 | 1 | 0.41 | 0.93 | 0.01 | 0.02 | 0.04 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 31 | 5 | 1 | 0.04 | 0.97 | 0.004 | 0.005 | 0.006 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 31 | 10 | 1 | 0.00 | 0.97 | 0 | 0.005 | 0.006 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 32 | 1 | 1 | 0.33 | 0.97 | 0.025 | 0.04 | 0.05 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 32 | 2 | 1 | 0.06 | 1.00 | 0.0001 | 0.0009 | 0.0015 | 0.15 | 0.15 | 0.15 | 0.05 | 0.1 | 0.15 |
| 32 | 10 | 1 | 0.02 | 0.80 | 0 | 0.0009 | 0.0015 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 33 | 1 | 1 | 0.50 | 1.00 | 0.02 | 0.03 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 33 | 2 | 1 | 0.15 | 0.85 | 0.03 | 0.035 | 0.07 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 33 | 3 | 1 | 0.68 | 0.94 | 0.06 | 0.1 | 0.15 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 33 | 4 | 1 | 0.29 | 0.96 | 0.001 | 0.003 | 0.01 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 33 | 5 | 1 | 0.63 | 1.00 | 0.04 | 0.06 | 0.08 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 33 | 10 | 1 | 0.00 | 1.00 | 0 | 0.003 | 0.01 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 34 | 1 | 1 | 0.11 | 0.87 | 0.02 | 0.025 | 0.03 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 34 | 2 | 1 | 0.15 | 0.85 | 0.02 | 0.03 | 0.05 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 34 | 3 | 1 | 0.16 | 0.96 | 0.008 | 0.012 | 0.018 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 34 | 4 | 1 | 0.19 | 0.98 | 0.002 | 0.004 | 0.01 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 34 | 10 | 1 | 0.03 | 1.00 | 0 | 0.004 | 0.01 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 35 | 1 | 1 | 0.57 | 0.95 | 0.04 | 0.06 | 0.1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 35 | 10 | 1 | 0.00 | 0.95 | 0 | 0.06 | 0.1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 36 | 1 | 1 | 0.54 | 0.91 | 0.01 | 0.02 | 0.03 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 36 | 2 | 1 | 0.70 | 0.89 | 0.04 | 0.06 | 0.1 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 36 | 3 | 1 | 0.19 | 0.92 | 0.02 | 0.03 | 0.04 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 36 | 4 | 1 | 0.65 | 0.94 | 0.02 | 0.03 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 36 | 5 | 1 | 0.50 | 1.00 | 0.02 | 0.03 | 0.06 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |

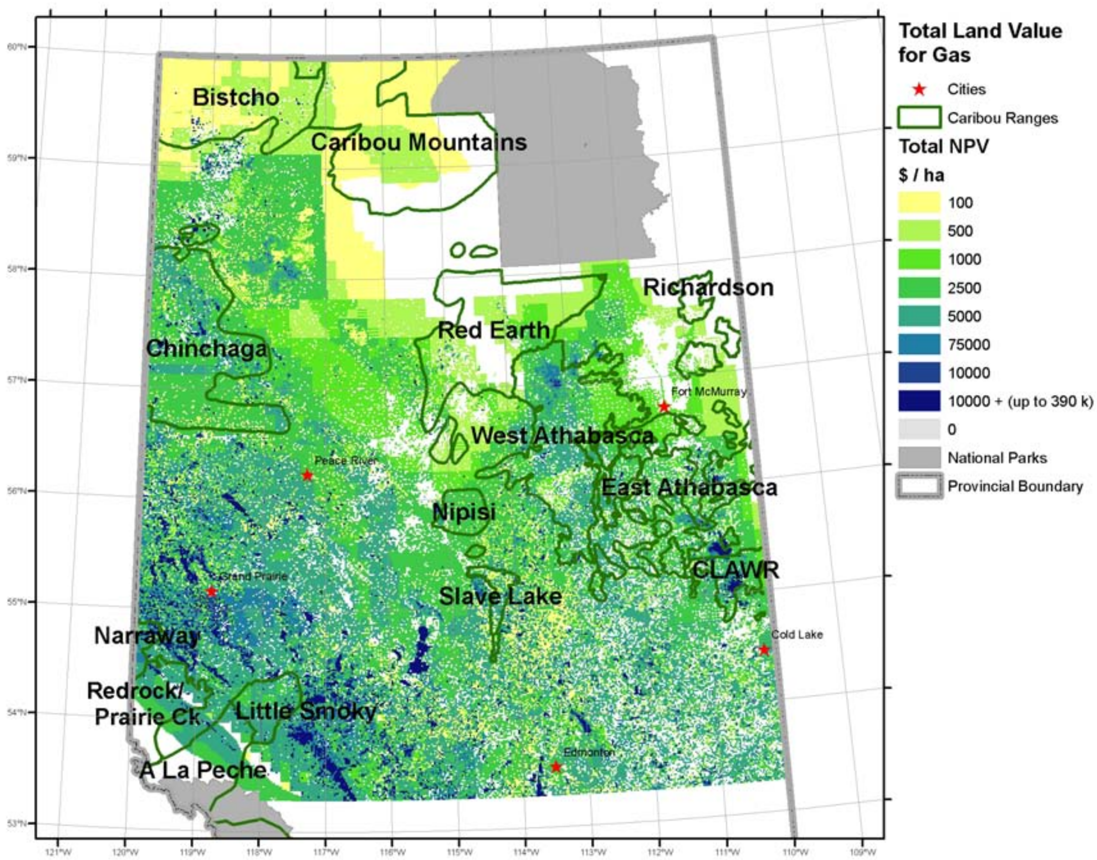
| Strat Inter -val | Play ID | Median # wells per tract | Success rate per tract | Proportion of Wells Successful given successful tract | Probability that a tract has future resources for three scenarios (From EUB/NEB) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Future tracts | | | Unconfirmed tracts | | | Bypassed tracts | | |
| | | | | | Low | Med. | High | Low | Med. | High | Low | Med. | High |
| 36 | 6 | 1 | 0.40 | 0.84 | 0.03 | 0.05 | 0.1 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 36 | 7 | 1 | 0.40 | 0.98 | 0.005 | 0.009 | 0.015 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 36 | 8 | 1 | 0.55 | 1.00 | 0.005 | 0.01 | 0.015 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 36 | 10 | 1 | 0.01 | 1.00 | 0 | 0.009 | 0.015 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 37 | 1 | 1 | 0.33 | 0.97 | 0.01 | 0.02 | 0.04 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 37 | 2 | 1 | 0.62 | 0.93 | 0.005 | 0.01 | 0.03 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 37 | 3 | 1 | 0.28 | 0.94 | 0.03 | 0.05 | 0.08 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 37 | 4 | 1 | 0.43 | 0.98 | 0.02 | 0.03 | 0.06 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 37 | 5 | 1 | 0.37 | 0.95 | 0.005 | 0.008 | 0.015 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 37 | 6 | 1 | 0.52 | 0.99 | 0.001 | 0.002 | 0.005 | 0.05 | 0.1 | 0.15 | 0 | 0.05 | 0.1 |
| 37 | 7 | 1 | 0.78 | 0.95 | 0.04 | 0.06 | 0.08 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 37 | 10 | 1 | 0.01 | 0.83 | 0 | 0.002 | 0.005 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 38 | 1 | 1 | 0.59 | 0.95 | 0.02 | 0.03 | 0.04 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 38 | 2 | 1 | 0.44 | 0.96 | 0.05 | 0.1 | 0.2 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 38 | 3 | 1 | 0.55 | 0.95 | 0.01 | 0.02 | 0.05 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 38 | 4 | 1 | 0.48 | 0.93 | 0.01 | 0.02 | 0.03 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 38 | 5 | 1 | 0.50 | 0.85 | 0.01 | 0.02 | 0.05 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 38 | 6 | 1 | 0.48 | 0.82 | 0.02 | 0.03 | 0.05 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 38 | 7 | 1 | 0.87 | 1.00 | 0.05 | 0.1 | 0.2 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 38 | 8 | 1 | 0.22 | 0.89 | 0.002 | 0.003 | 0.01 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 38 | 9 | 1 | 0.05 | 0.93 | 0.0001 | 0.0002 | 0.0003 | 0.15 | 0.15 | 0.15 | 0.05 | 0.1 | 0.15 |
| 38 | 10 | 1 | 0.02 | 0.85 | 0 | 0.0002 | 0.0003 | 0.10 | 0.2 | 0.3 | 0 | 0.05 | 0.1 |
| 39 | 1 | 1 | 0.49 | 0.96 | 0.003 | 0.005 | 0.01 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 39 | 2 | 1 | 0.79 | 0.90 | 0.01 | 0.02 | 0.04 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 39 | 3 | 1 | 0.90 | 0.96 | 0.01 | 0.02 | 0.04 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 39 | 4 | 1 | 0.80 | 0.96 | 0.02 | 0.03 | 0.08 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 39 | 5 | 1 | 0.50 | 0.96 | 0.03 | 0.05 | 0.12 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 39 | 6 | 1 | 0.60 | 0.98 | 0.01 | 0.02 | 0.03 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 39 | 7 | 1 | 0.51 | 1.00 | 0.01 | 0.013 | 0.03 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 39 | 8 | 1 | 0.56 | 0.95 | 0.02 | 0.04 | 0.06 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 39 | 9 | 1 | 0.82 | 0.92 | 0.03 | 0.05 | 0.1 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 39 | 10 | 1 | 0.00 | 1.00 | 0 | 0.005 | 0.01 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 40 | 1 | 1 | 0.10 | 0.96 | 0.002 | 0.0035 | 0.0045 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 40 | 2 | 1 | 0.41 | 0.79 | 0.02 | 0.04 | 0.08 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 40 | 10 | 1 | 0.00 | 1.00 | 0 | 0.0035 | 0.0045 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 41 | 1 | 1 | 0.87 | 0.99 | 0.03 | 0.05 | 0.12 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 41 | 2 | 1 | 0.74 | 1.00 | 0.005 | 0.01 | 0.02 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 42 | 1 | 1 | 0.52 | 0.87 | 0.01 | 0.02 | 0.04 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 42 | 2 | 1 | 0.86 | 0.91 | 0.04 | 0.08 | 0.16 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 42 | 3 | 1 | 0.77 | 0.91 | 0.1 | 0.2 | 0.4 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 42 | 4 | 1 | 0.12 | 0.95 | 0.01 | 0.02 | 0.04 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |
| 42 | 5 | 1 | 0.09 | 1.00 | 0 | 0.001 | 0.006 | 0.15 | 0.3 | 0.45 | 0.05 | 0.1 | 0.15 |
| 42 | 10 | 1 | 0.01 | 0.93 | 0 | 0.001 | 0.006 | 0.10 | 0.2 | 0.3 | 0.05 | 0.1 | 0.15 |

## 3. Results

Net present values for each tract were computed using equations 1, 2 and 3 and using data as discussed in the previous sections and where the discount rate $\beta_t = 1/(1+i)^t$ with $i$ was set at 0.04. This reflects a risk free real return on capital and is lower than gas companies would use. Hence, our NPVs will be higher than what gas exploration and development companies would obtain with a discount rate of say 0.10.

For each land section, the NPVs for each tract that were greater than zero were added up across all the tracts in the section (i.e., that is for each stratigraphic interval present below the section's land surface. This yielded a total land value for the section. Land values were developed for each of the three EUB/NEB ultimate potential scenarios, which in terms of the equation 1 to 3 means three different $p^{seis}$ scenarios for each play area. A map showing the total land values by section is presented in Figure 10.

Figure 10. Natural gas net present values for the EUB/NEB medium ultimate potential scenario.




The areas in the map where NPVs are shown to be relatively homogeneous reflect areas where there are a many tracts classified as future, which means they will have all the same estimated reserves and thus NPVs. The straight lines, particularly in the northwestern part of the map reflect play area boundaries. The map also shows areas of white areas speckled within the coloured areas on the map. These are areas where gas has already been fully exploited. The map suggests that lowest value gas areas are in the Bistcho, Caribou Mountains, Red Earth and Richardson herds.

The NPVs shown here are computed as if the initial investment would proceed immediately. This is not a realistic assumption because of the many constraints that face energy producers, such as drilling capacity, which will mean the gas wells will be built over a period of time. However, the output as presented in this fashion does give an indication of what priority areas would be if an optimal schedule of drilling were to be developed. We develop a schedule of drilling for natural gas, oil and bitumen in another paper.

*The value of gas resources in each caribou herd*

The unscheduled NPVs, may be added up within and outside the herds, to give a preliminary estimation of the relative value of resources in each herd. In addition, we can compute NPVs of royalties and taxes separately using equations 5 and 6. Again, these NPVs will overestimate the value because wells as assumed to be drilled immediately.

Tables 12, 13, and 14 show NPVs by herd and broken down by profits, computed from equations 1-3, royalties (equation 5), and taxes (equation 6). The total value is also reported. The NPVs are also computed for each ERCB ultimate potential scenario for natural gas. Table 12 gives the values for wells that already exist (equation 2). Table 13 gives NPVs for future wells (equations 1 and 3). Finally, Table 14 gives total NPVs over existing and future wells. In each of the tables the herds have been sorted with the smallest value herd in the medium ultimate potential scenario appearing first and the highest value herd appearing last.

The herds with the smallest gas values are Richardson, Caribou Mountains and Slave Lake. The caribou herds with the largest gas values are Chinchaga, West Athabasca and East Athabasca herds (See Table 15). A major reason for the larger NPVs in many of the herds is herd size. This is appropriate if each herd is considered an indivisible conservation unit. However, this is probably not realistic given the size of the values for some herds. In addition, there is substantial heterogeneity in the values within each herd. The marginal value per unit area (e.g. $/ha) or value per unit of some appropriate measure of conservation that incorporates the quality of habitat will be a more appropriate criterion if herds are divisible. This suggests a cost curves should be developed for each herd and a global cost curve should be developed across all herds. We do not pursue this here. However, computed average $/ha values for each herd to demonstrat how the objectives of caribou conservation might affect the ranking of lands within caribou herds for conservation. These averages are show in Table 16. The results indicate that average $/ha values are highest for Narraway, Little Smokey and Redrock-Prairie Creek. Cost curves will be developed in future papers.

Tables 12 to 14 also show how NPVs change with the ERCB ultimate potential scenarios. In most cases the NPVs increase for each category of NPV (profits, royalties, taxes and total) as we move from low to medium to high scenarios. However, this is not true in all cases. For example, Slave Lake total NPVs are lowest for the medium scenario and highest for the low scenario. This is due to the nature of the royalty system, which charges higher royalties for wells that are larger and our assumption that the number of wells used for extraction stays constant across the scenarios. The effect of the royalty assumption, which tries to capture more rent for larger wells, can be seen for the Slave Lake case. More royalties and taxes are collected as the estimate of future resources increases from low to high, while at the same time profits and total NPVs fall and then rise again only slightly (see Table 13 and 14). In other cases, while total NPVs increase with increases in estimated reserves, profits decrease as the royalty system captures more of the rents. This can be observed in the Narraway, and East Athabasca ranges and areas outside the caribou herd ranges.

Table 15 shows how the expected total gas extraction and the number of wells need to extract the gas change as the ultimate potential scenarios changes. The amount of gas extracted and the number increases from low to high scenarios as expected. In addition, the estimated future wells increase because the increase in expected future volumes increase the profitability of tracts from negative to positive.

Table 12. Net present values of profits, royalties, and taxes for existing wells for each ERCB ultimate potential scenario for conventional natural gas.

| | Low ERCB Potential Scenario | | | | Medium ERCB Potential Scenario | | | | High ERCB Potential Scenario | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HerdName | Prof. | Roy. | Tax | Tot. | Prof. | Roy. | Tax | Tot. | Prof. | Roy. | Tax | Tot. |
| Richardson | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Caribou Mountains | 1 | 1 | 0 | 2 | 1 | 1 | 0 | 2 | 1 | 1 | 0 | 2 |
| Nipisi | 15 | 3 | 5 | 23 | 16 | 3 | 5 | 24 | 17 | 4 | 5 | 26 |
| SlaveLake | 30 | 6 | 9 | 45 | 32 | 6 | 10 | 48 | 34 | 7 | 10 | 51 |
| RedEarth | 49 | 16 | 15 | 79 | 52 | 16 | 16 | 84 | 54 | 17 | 17 | 88 |
| Bistcho | 55 | 24 | 16 | 95 | 59 | 25 | 17 | 101 | 63 | 26 | 18 | 107 |
| ALaPeche | 68 | 21 | 11 | 101 | 71 | 22 | 11 | 104 | 72 | 23 | 12 | 107 |
| Narraway | 83 | 21 | 22 | 126 | 92 | 22 | 23 | 137 | 99 | 24 | 25 | 148 |
| Little Smoky | 115 | 33 | 28 | 175 | 124 | 35 | 30 | 190 | 131 | 40 | 33 | 204 |
| CLAWR | 141 | 28 | 46 | 215 | 145 | 28 | 46 | 219 | 148 | 29 | 47 | 223 |
| Redrock-PrairieCk | 160 | 34 | 28 | 222 | 165 | 34 | 28 | 227 | 168 | 35 | 29 | 232 |
| West Athabasca | 192 | 55 | 55 | 302 | 207 | 57 | 60 | 324 | 220 | 61 | 65 | 346 |
| East Athabasca | 302 | 47 | 87 | 436 | 332 | 50 | 93 | 474 | 356 | 56 | 100 | 512 |
| Chinchaga | 408 | 143 | 131 | 681 | 427 | 155 | 138 | 720 | 447 | 165 | 145 | 756 |
| Outside Herds | 7,439 | 2,199 | 1,984 | 11,621 | 8,128 | 2,340 | 2,119 | 12,587 | 8,737 | 2,519 | 2,279 | 13,535 |
| Total | 9,059 | 2,629 | 2,437 | 14,125 | 9,851 | 2,794 | 2,597 | 15,242 | 10,548 | 3,005 | 2,785 | 16,338 |

Table 13. Net present values of profits, royalties and taxes for future wells for each ERCB ultimate potential
scenario for conventional natural gas.

| | Low ERCB Potential Scenario | | | | Medium ERCB Potential Scenario | | | | High ERCB Potential Scenario | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Herd Name | Prof. | Roy. | Tax | Tot. | Prof. | Roy. | Tax | Tot. | Prof. | Roy. | Tax | Tot. |
| Richardson | 2 | 6 | 9 | 17 | 12 | 8 | 13 | 34 | 18 | 12 | 17 | 46 |
| Slave Lake | 552 | 73 | 89 | 713 | 194 | 87 | 108 | 390 | 253 | 111 | 140 | 504 |
| Caribou Mountains | 9 | 59 | 52 | 120 | 186 | 117 | 103 | 407 | 368 | 231 | 204 | 803 |
| Nipisi | 241 | 99 | 101 | 440 | 212 | 124 | 127 | 463 | 283 | 164 | 168 | 615 |
| Red Earth | 116 | 162 | 144 | 422 | 355 | 232 | 209 | 796 | 551 | 354 | 316 | 1,221 |
| Bistcho | 325 | 232 | 155 | 711 | 339 | 307 | 207 | 853 | 462 | 429 | 296 | 1,186 |
| CLAWR | 1,336 | 271 | 284 | 1,892 | 610 | 299 | 321 | 1,230 | 696 | 335 | 369 | 1,400 |
| Narraway | 817 | 368 | 207 | 1,392 | 470 | 501 | 278 | 1,249 | 709 | 772 | 418 | 1,900 |
| ALaPeche | 373 | 615 | 279 | 1,267 | 588 | 939 | 422 | 1,949 | 1,064 | 1,741 | 765 | 3,570 |
| Little Smoky | 959 | 727 | 421 | 2,106 | 921 | 969 | 558 | 2,448 | 1,378 | 1,491 | 842 | 3,711 |
| Redrock -PrairieCk | 840 | 861 | 398 | 2,099 | 868 | 1,254 | 570 | 2,692 | 1,414 | 2,150 | 952 | 4,516 |
| East Athabasca | 2,791 | 698 | 796 | 4,284 | 1,736 | 840 | 991 | 3,568 | 2,228 | 1,046 | 1,266 | 4,540 |
| West Athabasca | 1,732 | 626 | 850 | 3,208 | 1,894 | 859 | 1,140 | 3,893 | 2,633 | 1,205 | 1,554 | 5,392 |
| Chinchaga | 2,828 | 1,927 | 1,295 | 6,050 | 3,223 | 2,539 | 1,729 | 7,490 | 5,022 | 4,107 | 2,683 | 11,812 |
| Outside Herds | 56,855 | 31,113 | 22,610 | 110,578 | 51,223 | 38,400 | 28,219 | 117,842 | 68,183 | 52,005 | 37,910 | 158,098 |
| Total | 69,776 | 37,835 | 27,690 | 135,301 | 62,831 | 47,477 | 34,996 | 145,304 | 85,261 | 66,152 | 47,900 | 199,314 |

Table 14. Net present values of profits, royalties, and taxes for all wells for each ERCB ultimate potential
scenario for conventional gas.

| | Low ERCB Potential Scenario | | | | Medium ERCB Potential Scenario | | | | High ERCB Potential Scenario | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HerdName | Prof. | Roy. | Tax | Tot. | Prof. | Roy. | Tax | Tot. | Prof. | Roy. | Tax | Tot. |
| Richardson | 2 | 6 | 9 | 17 | 12 | 8 | 13 | 34 | 18 | 12 | 17 | 46 |
| Caribou Mountains | 10 | 60 | 53 | 122 | 187 | 118 | 104 | 409 | 369 | 232 | 205 | 806 |
| Slave Lake | 581 | 79 | 97 | 757 | 226 | 94 | 118 | 438 | 288 | 117 | 150 | 555 |
| Nipisi | 256 | 102 | 105 | 463 | 228 | 127 | 132 | 487 | 300 | 167 | 173 | 641 |
| Red Earth | 165 | 178 | 159 | 501 | 407 | 248 | 225 | 880 | 605 | 371 | 333 | 1,309 |
| Bistcho | 380 | 256 | 171 | 806 | 398 | 331 | 224 | 954 | 524 | 455 | 314 | 1,293 |
| Narraway | 900 | 389 | 229 | 1,518 | 562 | 523 | 301 | 1,386 | 808 | 796 | 444 | 2,048 |
| CLAWR | 1,477 | 299 | 330 | 2,106 | 754 | 326 | 368 | 1,449 | 844 | 364 | 416 | 1,623 |
| ALaPeche | 442 | 636 | 291 | 1,369 | 658 | 962 | 434 | 2,053 | 1,136 | 1,764 | 777 | 3,677 |
| Little Smoky | 1,073 | 760 | 449 | 2,282 | 1,045 | 1,005 | 589 | 2,638 | 1,509 | 1,531 | 875 | 3,915 |
| Redrock -PrairieCk | 1,000 | 894 | 426 | 2,321 | 1,033 | 1,289 | 598 | 2,920 | 1,582 | 2,185 | 981 | 4,748 |
| East Athabasca | 3,093 | 745 | 882 | 4,720 | 2,068 | 890 | 1,084 | 4,042 | 2,584 | 1,102 | 1,366 | 5,051 |
| West Athabasca | 1,923 | 681 | 905 | 3,510 | 2,101 | 916 | 1,200 | 4,217 | 2,853 | 1,266 | 1,619 | 5,738 |
| Chinchaga | 3,236 | 2,069 | 1,426 | 6,731 | 3,650 | 2,694 | 1,866 | 8,210 | 5,469 | 4,272 | 2,828 | 12,568 |
| Outsided Herds | 64,294 | 33,311 | 24,594 | 122,199 | 59,351 | 40,740 | 30,338 | 130,429 | 76,921 | 54,524 | 40,189 | 171,633 |
| Total | 78,834 | 40,464 | 30,127 | 149,425 | 72,682 | 50,271 | 37,593 | 160,546 | 95,809 | 69,158 | 50,686 | 215,652 |

Table 15. Estimated gas extraction and numbers of wells, past and future, for each herd and ERCB ultimate potential scenario for conventional gas.

| HerdName | ERCB Low Scenario | | | ERCB Medium Scenario | | | ERCB High Scenario | | |
|---|---|---|---|---|---|---|---|---|---|
| | Gas million m3 | Est. Future Wells | Existing Wells | Gas million m3 | Est. Future Wells | Existing Wells | Gas million m3 | Est. Future Wells | Existing Wells |
| Richardson | 282 | 117 | 15 | 389 | 151 | 15 | 515 | 187 | 15 |
| Caribou Mountains | 1,760 | 213 | 3 | 3,462 | 420 | 3 | 6,772 | 828 | 3 |
| Slave Lake | 3,497 | 548 | 211 | 4,167 | 621 | 211 | 5,133 | 739 | 211 |
| Nipisi | 3,710 | 659 | 194 | 4,624 | 797 | 194 | 6,021 | 983 | 194 |
| RedEarth | 6,017 | 930 | 279 | 8,400 | 1,233 | 279 | 12,267 | 1,650 | 279 |
| Bistcho | 6,567 | 711 | 169 | 8,821 | 976 | 169 | 13,061 | 1,394 | 169 |
| Narraway | 10,304 | 637 | 374 | 13,543 | 697 | 374 | 19,826 | 791 | 374 |
| CLAWR | 11,213 | 1,941 | 1,039 | 12,458 | 2,102 | 1,039 | 14,028 | 2,295 | 1,039 |
| ALaPeche | 17,506 | 347 | 153 | 25,584 | 431 | 153 | 42,576 | 589 | 153 |
| Little Smoky | 23,437 | 1,283 | 690 | 31,773 | 1,487 | 690 | 46,326 | 1,803 | 690 |
| Redrock-PrairieCk | 26,187 | 688 | 347 | 35,748 | 811 | 347 | 55,213 | 1,021 | 347 |
| East Athabasca | 31,888 | 5,767 | 2,386 | 38,637 | 6,816 | 2,386 | 47,657 | 8,018 | 2,386 |
| West Athabasca | 30,997 | 5,526 | 1,282 | 40,604 | 7,088 | 1,282 | 53,658 | 8,898 | 1,282 |
| Chinchaga | 53,456 | 4,273 | 1,289 | 69,425 | 5,436 | 1,289 | 103,951 | 7,398 | 1,289 |
| Outside Herds | 953,477 | 92,487 | 37,669 | 1,182,746 | 109,143 | 37,669 | 1,565,263 | 133,647 | 37,669 |
| Grand Total | 1,180,297 | 116,125 | 46,100 | 1,480,382 | 138,208 | 46,100 | 1,992,267 | 170,242 | 46,100 |

Table 16. NPVs per unit area ($/ha) for each herd and ERCB ultimate potential scenario.

| HerdName | Herd Area 1000 ha | $/ha Profits by herd | | | $/ha Profits+Royalties+Taxes by herd | | |
|---|---|---|---|---|---|---|---|
| | | Low | Medium | High | Low | Medium | High |
| Richardson | 270 | 8 | 46 | 65 | 64 | 124 | 170 |
| CaribouMountains | 1,866 | 5 | 100 | 198 | 66 | 219 | 432 |
| SlaveLake | 134 | 4,338 | 1,689 | 2,146 | 5,652 | 3,267 | 4,140 |
| Nipisi | 208 | 1,231 | 1,097 | 1,442 | 2,226 | 2,341 | 3,081 |
| RedEarth | 1,600 | 103 | 255 | 378 | 313 | 550 | 818 |
| Bistcho | 1,280 | 296 | 311 | 410 | 630 | 745 | 1,011 |
| Narraway | 102 | 8,828 | 5,510 | 7,925 | 14,885 | 13,591 | 20,078 |
| CLAWR | 269 | 5,492 | 2,804 | 3,137 | 7,831 | 5,385 | 6,035 |
| ALaPeche | 625 | 707 | 1,053 | 1,818 | 2,190 | 3,285 | 5,884 |
| LittleSmoky | 292 | 3,676 | 3,577 | 5,168 | 7,815 | 9,034 | 13,406 |
| Redrock-PrairieCk | 465 | 2,152 | 2,221 | 3,402 | 4,991 | 6,279 | 10,211 |
| EastAthabasca | 1,473 | 2,100 | 1,404 | 1,754 | 3,205 | 2,744 | 3,429 |
| WestAthabasca | 1,504 | 1,279 | 1,397 | 1,897 | 2,334 | 2,804 | 3,815 |
| Chinchaga | 1,710 | 1,892 | 2,135 | 3,198 | 3,936 | 4,801 | 7,350 |

## 4 Discussion and Conclusions

In this paper we developed a NPV model of conventional natural gas drilling. We then proceeded to describe the data and computations that were required for each variable and parameter in the model. The net present value model is written from the perspective of a gas company that explores for gas using seismic and drilling and then develops gas resources by completing wells and then extracting the gas.

Several weaknesses exist in the model. One is that it describes only marginal activities of the gas company. Hence, computation of corporate taxes can only be approximated. Royalty calculations are restricted to the main aspects of Alberta's new royalty system, implemented starting in January 2009. Elements such as the transition well program, which features reduced royalty rates, are ignored here for the sake of simplicity. Other issues relate to data. First, the ultimate potential data is up to date to the end of 2004 so there have been several years of activity since then. In this paper, we made no attempt to update the data as this would have entailed more resources than were available. Another problem with the ultimate potential database developed by ERCB and NEB is that it does not contain depth data. Since drilling depth is a major determinant of cost we need to find a way of estimating depths for each layer. Hence, we developed the matching procedure described in section 2 which may not have accurately matched wells to strata in all cases.

In section three we presented a sensitivity analysis on the ERCB ultimate potential scenarios to see the effect of increasing expected reserves sizes by increasing the a priori probability of discovery $p_{sm}^{EUB}$. This was an obvious analysis to perform due to the inherent uncertainties in the data we obtained from the ERCB ultimate potential database.

However, there are other sensitivity analyses we could perform on other variables in the model which include price forecasts, success rates, numbers of wells need to extract gas, size of future reserves and so on. Since the main purpose of the this paper was to present the methods used to estimate the value of natural gas reserves for use in subsequent models we leave these sensitivity analyses for future papers.

The analysis presented here, although incomplete, does show substantial differences in gas resource values across the herds. However, the ranking of herds by NPV of resources does significantly differ if one uses total herd values and $/ha values. The former is relevant if herds are considered indivisible for conservation purposes while the latter is relevant if herds are divisible. Hence, in future analyses it will be important to consider the specific objectives of caribou conservation and recovery, such as whether all herds must be recovered, whether some herds may be allowed to extirpate as long as others are recovered, and to what extent herds (particularly the large ones) may be subdivided into areas of development and areas of protection.

Table A1. Gas production profiles from representative wells by PSAC region. Taken from profiles given in Alberta Department of Energy (2007a) and converted to m3.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|
| 1 | 3 | 1 | 1133 | 198 | 0.175 |
| 1 | 3 | 2 | 1133 | 170 | 0.150 |
| 1 | 3 | 3 | 1133 | 170 | 0.150 |
| 1 | 3 | 4 | 1133 | 113 | 0.100 |
| 1 | 3 | 5 | 1133 | 85 | 0.075 |
| 1 | 3 | 6 | 1133 | 57 | 0.050 |
| 1 | 3 | 7 | 1133 | 142 | 0.125 |
| 1 | 3 | 8 | 1133 | 113 | 0.100 |
| 1 | 3 | 9 | 1133 | 85 | 0.075 |
| 1 | 3 | 10 | 1133 | 0 | 0.000 |
| 2 | 4 | 1 | 1133 | 538 | 0.475 |
| 2 | 4 | 2 | 1133 | 396 | 0.350 |
| 2 | 4 | 3 | 1133 | 198 | 0.175 |
| 2 | 4 | 4 | 1133 | 0 | 0.000 |
| 3 | 5 | 1 | 2152 | 821 | 0.382 |
| 3 | 5 | 2 | 2152 | 510 | 0.237 |
| 3 | 5 | 3 | 2152 | 283 | 0.132 |
| 3 | 5 | 4 | 2152 | 227 | 0.105 |
| 3 | 5 | 5 | 2152 | 170 | 0.079 |
| 3 | 5 | 6 | 2152 | 142 | 0.066 |
| 3 | 5 | 7 | 2152 | 0 | 0.000 |
| 4 | 3 | 1 | 2464 | 510 | 0.207 |
| 4 | 3 | 2 | 2464 | 396 | 0.161 |
| 4 | 3 | 3 | 2464 | 368 | 0.149 |
| 4 | 3 | 4 | 2464 | 227 | 0.092 |
| 4 | 3 | 5 | 2464 | 142 | 0.057 |
| 4 | 3 | 6 | 2464 | 113 | 0.046 |
| 4 | 3 | 7 | 2464 | 255 | 0.103 |
| 4 | 3 | 8 | 2464 | 283 | 0.115 |
| 4 | 3 | 9 | 2464 | 170 | 0.069 |
| 4 | 3 | 10 | 2464 | 0 | 0.000 |
| 5 | 6 | 1 | 2464 | 821 | 0.333 |
| 5 | 6 | 2 | 2464 | 623 | 0.253 |
| 5 | 6 | 3 | 2464 | 255 | 0.103 |
| 5 | 6 | 4 | 2464 | 198 | 0.080 |
| 5 | 6 | 5 | 2464 | 198 | 0.080 |
| 5 | 6 | 6 | 2464 | 198 | 0.080 |
| 5 | 6 | 7 | 2464 | 170 | 0.069 |
| 5 | 6 | 8 | 2464 | 0 | 0.000 |
| 6 | 4 | 1 | 3002 | 1303 | 0.434 |
| 6 | 4 | 2 | 3002 | 1048 | 0.349 |
| 6 | 4 | 3 | 3002 | 566 | 0.189 |
| 6 | 4 | 4 | 3002 | 85 | 0.028 |
| 6 | 4 | 5 | 3002 | 0 | 0.000 |

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|
| 7 | 3 | 1 | 3681 | 736 | 0.200 |
| 7 | 3 | 2 | 3681 | 566 | 0.154 |
| 7 | 3 | 3 | 3681 | 481 | 0.131 |
| 7 | 3 | 4 | 3681 | 396 | 0.108 |
| 7 | 3 | 5 | 3681 | 340 | 0.092 |
| 7 | 3 | 6 | 3681 | 255 | 0.069 |
| 7 | 3 | 7 | 3681 | 227 | 0.062 |
| 7 | 3 | 8 | 3681 | 170 | 0.046 |
| 7 | 3 | 9 | 3681 | 142 | 0.038 |
| 7 | 3 | 10 | 3681 | 113 | 0.031 |
| 7 | 3 | 11 | 3681 | 85 | 0.023 |
| 7 | 3 | 12 | 3681 | 28 | 0.008 |
| 7 | 3 | 13 | 3681 | 28 | 0.008 |
| 7 | 3 | 14 | 3681 | 28 | 0.008 |
| 7 | 3 | 15 | 3681 | 28 | 0.008 |
| 7 | 3 | 16 | 3681 | 28 | 0.008 |
| 7 | 3 | 17 | 3681 | 28 | 0.008 |
| 7 | 3 | 18 | 3681 | 0 | 0.000 |
| 8 | 7 | 1 | 3681 | 1218 | 0.331 |
| 8 | 7 | 2 | 3681 | 906 | 0.246 |
| 8 | 7 | 3 | 3681 | 651 | 0.177 |
| 8 | 7 | 4 | 3681 | 368 | 0.100 |
| 8 | 7 | 5 | 3681 | 255 | 0.069 |
| 8 | 7 | 6 | 3681 | 227 | 0.062 |
| 8 | 7 | 7 | 3681 | 57 | 0.015 |
| 8 | 7 | 8 | 3681 | 0 | 0.000 |
| 9 | 5 | 1 | 4332 | 1614 | 0.373 |
| 9 | 5 | 2 | 4332 | 1076 | 0.248 |
| 9 | 5 | 3 | 4332 | 538 | 0.124 |
| 9 | 5 | 4 | 4332 | 425 | 0.098 |
| 9 | 5 | 5 | 4332 | 340 | 0.078 |
| 9 | 5 | 6 | 4332 | 311 | 0.072 |
| 9 | 5 | 7 | 4332 | 28 | 0.007 |
| 9 | 5 | 8 | 4332 | 0 | 0.000 |
| 10 | 6 | 1 | 4757 | 1614 | 0.339 |
| 10 | 6 | 2 | 4757 | 1189 | 0.250 |
| 10 | 6 | 3 | 4757 | 481 | 0.101 |
| 10 | 6 | 4 | 4757 | 368 | 0.077 |
| 10 | 6 | 5 | 4757 | 396 | 0.083 |
| 10 | 6 | 6 | 4757 | 396 | 0.083 |
| 10 | 6 | 7 | 4757 | 311 | 0.065 |
| 10 | 6 | 8 | 4757 | 0 | 0.000 |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|
| 11 | 3 | 1 | 4814 | 963 | 0.200 |
| 11 | 3 | 2 | 4814 | 736 | 0.153 |
| 11 | 3 | 3 | 4814 | 623 | 0.129 |
| 11 | 3 | 4 | 4814 | 510 | 0.106 |
| 11 | 3 | 5 | 4814 | 425 | 0.088 |
| 11 | 3 | 6 | 4814 | 340 | 0.071 |
| 11 | 3 | 7 | 4814 | 255 | 0.053 |
| 11 | 3 | 8 | 4814 | 198 | 0.041 |
| 11 | 3 | 9 | 4814 | 170 | 0.035 |
| 11 | 3 | 10 | 4814 | 142 | 0.029 |
| 11 | 3 | 11 | 4814 | 142 | 0.029 |
| 11 | 3 | 12 | 4814 | 85 | 0.018 |
| 11 | 3 | 13 | 4814 | 57 | 0.012 |
| 11 | 3 | 14 | 4814 | 57 | 0.012 |
| 11 | 3 | 15 | 4814 | 57 | 0.012 |
| 11 | 3 | 16 | 4814 | 28 | 0.006 |
| 11 | 3 | 17 | 4814 | 28 | 0.006 |
| 11 | 3 | 18 | 4814 | 0 | 0.000 |
| 12 | 2 | 1 | 5125 | 1586 | 0.309 |
| 12 | 2 | 2 | 5125 | 1161 | 0.227 |
| 12 | 2 | 3 | 5125 | 934 | 0.182 |
| 12 | 2 | 4 | 5125 | 623 | 0.122 |
| 12 | 2 | 5 | 5125 | 396 | 0.077 |
| 12 | 2 | 6 | 5125 | 255 | 0.050 |
| 12 | 2 | 7 | 5125 | 142 | 0.028 |
| 12 | 2 | 8 | 5125 | 28 | 0.006 |
| 12 | 2 | 9 | 5125 | 0 | 0.000 |
| 13 | 4 | 1 | 6541 | 1784 | 0.273 |
| 13 | 4 | 2 | 6541 | 1472 | 0.225 |
| 13 | 4 | 3 | 6541 | 1189 | 0.182 |
| 13 | 4 | 4 | 6541 | 821 | 0.126 |
| 13 | 4 | 5 | 6541 | 566 | 0.087 |
| 13 | 4 | 6 | 6541 | 340 | 0.052 |
| 13 | 4 | 7 | 6541 | 227 | 0.035 |
| 13 | 4 | 8 | 6541 | 85 | 0.013 |
| 13 | 4 | 9 | 6541 | 57 | 0.009 |
| 13 | 4 | 10 | 6541 | 28 | 0.004 |
| 13 | 4 | 11 | 6541 | 0 | 0.000 |
| 14 | 2 | 1 | 7532 | 2350 | 0.312 |
| 14 | 2 | 2 | 7532 | 1699 | 0.226 |
| 14 | 2 | 3 | 7532 | 1388 | 0.184 |
| 14 | 2 | 4 | 7532 | 934 | 0.124 |
| 14 | 2 | 5 | 7532 | 538 | 0.071 |
| 14 | 2 | 6 | 7532 | 368 | 0.049 |
| 14 | 2 | 7 | 7532 | 198 | 0.026 |
| 14 | 2 | 8 | 7532 | 57 | 0.008 |
| 14 | 2 | 9 | 7532 | 0 | 0.000 |
| 15 | 7 | 1 | 8099 | 2662 | 0.329 |
| 15 | 7 | 2 | 8099 | 2067 | 0.255 |
| 15 | 7 | 3 | 8099 | 1472 | 0.182 |
| 15 | 7 | 4 | 8099 | 906 | 0.112 |
| 15 | 7 | 5 | 8099 | 453 | 0.056 |
| 15 | 7 | 6 | 8099 | 453 | 0.056 |
| 15 | 7 | 7 | 8099 | 113 | 0.014 |
| 15 | 7 | 8 | 8099 | 0 | 0.000 |
| 16 | 4 | 1 | 9401 | 2548 | 0.271 |
| 16 | 4 | 2 | 9401 | 2095 | 0.223 |
| 16 | 4 | 3 | 9401 | 1699 | 0.181 |
| 16 | 4 | 4 | 9401 | 1189 | 0.127 |
| 16 | 4 | 5 | 9401 | 821 | 0.087 |
| 16 | 4 | 6 | 9401 | 453 | 0.048 |
| 16 | 4 | 7 | 9401 | 283 | 0.030 |
| 16 | 4 | 8 | 9401 | 142 | 0.015 |
| 16 | 4 | 9 | 9401 | 142 | 0.015 |
| 16 | 4 | 10 | 9401 | 57 | 0.006 |
| 16 | 4 | 11 | 9401 | 0 | 0.000 |
| 17 | 5 | 1 | 10590 | 2605 | 0.246 |
| 17 | 5 | 2 | 10590 | 1982 | 0.187 |
| 17 | 5 | 3 | 10590 | 1614 | 0.152 |
| 17 | 5 | 4 | 10590 | 1331 | 0.126 |
| 17 | 5 | 5 | 10590 | 1019 | 0.096 |
| 17 | 5 | 6 | 10590 | 566 | 0.053 |
| 17 | 5 | 7 | 10590 | 396 | 0.037 |
| 17 | 5 | 8 | 10590 | 283 | 0.027 |
| 17 | 5 | 9 | 10590 | 198 | 0.019 |
| 17 | 5 | 10 | 10590 | 198 | 0.019 |
| 17 | 5 | 11 | 10590 | 113 | 0.011 |
| 17 | 5 | 12 | 10590 | 57 | 0.005 |
| 17 | 5 | 13 | 10590 | 57 | 0.005 |
| 17 | 5 | 14 | 10590 | 57 | 0.005 |
| 17 | 5 | 15 | 10590 | 57 | 0.005 |
| 17 | 5 | 16 | 10590 | 28 | 0.003 |
| 17 | 5 | 17 | 10590 | 0 | 0.000 |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well | Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 3 | 1 | 12091 | 2464 | 0.204 | 20 | 7 | 1 | 13903 | 3596 | 0.259 |
| 18 | 3 | 2 | 12091 | 1727 | 0.143 | 20 | 7 | 2 | 13903 | 2775 | 0.200 |
| 18 | 3 | 3 | 12091 | 1331 | 0.110 | 20 | 7 | 3 | 13903 | 2237 | 0.161 |
| 18 | 3 | 4 | 12091 | 1104 | 0.091 | 20 | 7 | 4 | 13903 | 1586 | 0.114 |
| 18 | 3 | 5 | 12091 | 934 | 0.077 | 20 | 7 | 5 | 13903 | 1161 | 0.084 |
| 18 | 3 | 6 | 12091 | 736 | 0.061 | 20 | 7 | 6 | 13903 | 793 | 0.057 |
| 18 | 3 | 7 | 12091 | 595 | 0.049 | 20 | 7 | 7 | 13903 | 538 | 0.039 |
| 18 | 3 | 8 | 12091 | 481 | 0.040 | 20 | 7 | 8 | 13903 | 425 | 0.031 |
| 18 | 3 | 9 | 12091 | 396 | 0.033 | 20 | 7 | 9 | 13903 | 283 | 0.020 |
| 18 | 3 | 10 | 12091 | 340 | 0.028 | 20 | 7 | 10 | 13903 | 170 | 0.012 |
| 18 | 3 | 11 | 12091 | 311 | 0.026 | 20 | 7 | 11 | 13903 | 113 | 0.008 |
| 18 | 3 | 12 | 12091 | 255 | 0.021 | 20 | 7 | 12 | 13903 | 113 | 0.008 |
| 18 | 3 | 13 | 12091 | 227 | 0.019 | 20 | 7 | 13 | 13903 | 113 | 0.008 |
| 18 | 3 | 14 | 12091 | 170 | 0.014 | 20 | 7 | 14 | 13903 | 28 | 0.002 |
| 18 | 3 | 15 | 12091 | 142 | 0.012 | 20 | 7 | 15 | 13903 | 0 | 0.000 |
| 18 | 3 | 16 | 12091 | 142 | 0.012 | 21 | 3 | 1 | 14895 | 3002 | 0.202 |
| 18 | 3 | 17 | 12091 | 142 | 0.012 | 21 | 3 | 2 | 14895 | 2152 | 0.144 |
| 18 | 3 | 18 | 12091 | 113 | 0.009 | 21 | 3 | 3 | 14895 | 1671 | 0.112 |
| 18 | 3 | 19 | 12091 | 113 | 0.009 | 21 | 3 | 4 | 14895 | 1388 | 0.093 |
| 18 | 3 | 20 | 12091 | 113 | 0.009 | 21 | 3 | 5 | 14895 | 1133 | 0.076 |
| 18 | 3 | 21 | 12091 | 57 | 0.005 | 21 | 3 | 6 | 14895 | 906 | 0.061 |
| 18 | 3 | 22 | 12091 | 28 | 0.002 | 21 | 3 | 7 | 14895 | 736 | 0.049 |
| 18 | 3 | 23 | 12091 | 28 | 0.002 | 21 | 3 | 8 | 14895 | 595 | 0.040 |
| 18 | 3 | 24 | 12091 | 28 | 0.002 | 21 | 3 | 9 | 14895 | 510 | 0.034 |
| 18 | 3 | 25 | 12091 | 28 | 0.002 | 21 | 3 | 10 | 14895 | 425 | 0.029 |
| 18 | 3 | 26 | 12091 | 28 | 0.002 | 21 | 3 | 11 | 14895 | 340 | 0.023 |
| 18 | 3 | 27 | 12091 | 28 | 0.002 | 21 | 3 | 12 | 14895 | 311 | 0.021 |
| 18 | 3 | 28 | 12091 | 28 | 0.002 | 21 | 3 | 13 | 14895 | 255 | 0.017 |
| 18 | 3 | 29 | 12091 | 28 | 0.002 | 21 | 3 | 14 | 14895 | 198 | 0.013 |
| 18 | 3 | 30 | 12091 | 0 | 0.000 | 21 | 3 | 15 | 14895 | 170 | 0.011 |
| 19 | 5 | 1 | 13620 | 3398 | 0.249 | 21 | 3 | 16 | 14895 | 142 | 0.010 |
| 19 | 5 | 2 | 13620 | 2520 | 0.185 | 21 | 3 | 17 | 14895 | 142 | 0.010 |
| 19 | 5 | 3 | 13620 | 2067 | 0.152 | 21 | 3 | 18 | 14895 | 113 | 0.008 |
| 19 | 5 | 4 | 13620 | 1727 | 0.127 | 21 | 3 | 19 | 14895 | 113 | 0.008 |
| 19 | 5 | 5 | 13620 | 1274 | 0.094 | 21 | 3 | 20 | 14895 | 113 | 0.008 |
| 19 | 5 | 6 | 13620 | 765 | 0.056 | 21 | 3 | 21 | 14895 | 85 | 0.006 |
| 19 | 5 | 7 | 13620 | 510 | 0.037 | 21 | 3 | 22 | 14895 | 57 | 0.004 |
| 19 | 5 | 8 | 13620 | 340 | 0.025 | 21 | 3 | 23 | 14895 | 57 | 0.004 |
| 19 | 5 | 9 | 13620 | 255 | 0.019 | 21 | 3 | 24 | 14895 | 57 | 0.004 |
| 19 | 5 | 10 | 13620 | 198 | 0.015 | 21 | 3 | 25 | 14895 | 57 | 0.004 |
| 19 | 5 | 11 | 13620 | 142 | 0.010 | 21 | 3 | 26 | 14895 | 57 | 0.004 |
| 19 | 5 | 12 | 13620 | 113 | 0.008 | 21 | 3 | 27 | 14895 | 57 | 0.004 |
| 19 | 5 | 13 | 13620 | 113 | 0.008 | 21 | 3 | 28 | 14895 | 57 | 0.004 |
| 19 | 5 | 14 | 13620 | 113 | 0.008 | 21 | 3 | 29 | 14895 | 28 | 0.002 |
| 19 | 5 | 15 | 13620 | 113 | 0.008 | 21 | 3 | 30 | 14895 | 0 | 0.000 |
| 19 | 5 | 16 | 13620 | 28 | 0.002 | | | | | | |
| 19 | 5 | 17 | 13620 | 0 | 0.000 | | | | | | |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|
| 22 | 6 | 1 | 15404 | 4078 | 0.265 |
| 22 | 6 | 2 | 15404 | 2860 | 0.186 |
| 22 | 6 | 3 | 15404 | 2124 | 0.138 |
| 22 | 6 | 4 | 15404 | 1614 | 0.105 |
| 22 | 6 | 5 | 15404 | 1218 | 0.079 |
| 22 | 6 | 6 | 15404 | 906 | 0.059 |
| 22 | 6 | 7 | 15404 | 708 | 0.046 |
| 22 | 6 | 8 | 15404 | 510 | 0.033 |
| 22 | 6 | 9 | 15404 | 396 | 0.026 |
| 22 | 6 | 10 | 15404 | 283 | 0.018 |
| 22 | 6 | 11 | 15404 | 198 | 0.013 |
| 22 | 6 | 12 | 15404 | 170 | 0.011 |
| 22 | 6 | 13 | 15404 | 113 | 0.007 |
| 22 | 6 | 14 | 15404 | 57 | 0.004 |
| 22 | 6 | 15 | 15404 | 57 | 0.004 |
| 22 | 6 | 16 | 15404 | 57 | 0.004 |
| 22 | 6 | 17 | 15404 | 28 | 0.002 |
| 22 | 6 | 18 | 15404 | 0 | 0.000 |
| 23 | 6 | 1 | 19397 | 5097 | 0.263 |
| 23 | 6 | 2 | 19397 | 3596 | 0.185 |
| 23 | 6 | 3 | 19397 | 2662 | 0.137 |
| 23 | 6 | 4 | 19397 | 2010 | 0.104 |
| 23 | 6 | 5 | 19397 | 1557 | 0.080 |
| 23 | 6 | 6 | 19397 | 1133 | 0.058 |
| 23 | 6 | 7 | 19397 | 878 | 0.045 |
| 23 | 6 | 8 | 19397 | 651 | 0.034 |
| 23 | 6 | 9 | 19397 | 510 | 0.026 |
| 23 | 6 | 10 | 19397 | 340 | 0.018 |
| 23 | 6 | 11 | 19397 | 283 | 0.015 |
| 23 | 6 | 12 | 19397 | 198 | 0.010 |
| 23 | 6 | 13 | 19397 | 170 | 0.009 |
| 23 | 6 | 14 | 19397 | 113 | 0.006 |
| 23 | 6 | 15 | 19397 | 113 | 0.006 |
| 23 | 6 | 16 | 19397 | 113 | 0.006 |
| 23 | 6 | 17 | 19397 | 57 | 0.003 |
| 23 | 6 | 18 | 19397 | 0 | 0.000 |
| 24 | 7 | 1 | 21492 | 5550 | 0.258 |
| 24 | 7 | 2 | 21492 | 4304 | 0.200 |
| 24 | 7 | 3 | 21492 | 3483 | 0.162 |
| 24 | 7 | 4 | 21492 | 2464 | 0.115 |
| 24 | 7 | 5 | 21492 | 1812 | 0.084 |
| 24 | 7 | 6 | 21492 | 1189 | 0.055 |
| 24 | 7 | 7 | 21492 | 821 | 0.038 |
| 24 | 7 | 8 | 21492 | 623 | 0.029 |
| 24 | 7 | 9 | 21492 | 425 | 0.020 |
| 24 | 7 | 10 | 21492 | 311 | 0.014 |
| 24 | 7 | 11 | 21492 | 198 | 0.009 |
| 24 | 7 | 12 | 21492 | 142 | 0.007 |
| 24 | 7 | 13 | 21492 | 142 | 0.007 |
| 24 | 7 | 14 | 21492 | 57 | 0.003 |
| 25 | 1 | 1 | 21804 | 6116 | 0.281 |
| 25 | 1 | 2 | 21804 | 4984 | 0.229 |
| 25 | 1 | 3 | 21804 | 3540 | 0.162 |
| 25 | 1 | 4 | 21804 | 2265 | 0.104 |
| 25 | 1 | 5 | 21804 | 1472 | 0.068 |
| 25 | 1 | 6 | 21804 | 1557 | 0.071 |
| 25 | 1 | 7 | 21804 | 963 | 0.044 |
| 25 | 1 | 8 | 21804 | 566 | 0.026 |
| 25 | 1 | 9 | 21804 | 311 | 0.014 |
| 25 | 1 | 10 | 21804 | 28 | 0.001 |
| 25 | 1 | 11 | 21804 | 0 | 0.000 |
| 26 | 1 | 1 | 26957 | 7561 | 0.280 |
| 26 | 1 | 2 | 26957 | 6145 | 0.228 |
| 26 | 1 | 3 | 26957 | 4389 | 0.163 |
| 26 | 1 | 4 | 26957 | 2803 | 0.104 |
| 26 | 1 | 5 | 26957 | 1812 | 0.067 |
| 26 | 1 | 6 | 26957 | 1897 | 0.070 |
| 26 | 1 | 7 | 26957 | 1189 | 0.044 |
| 26 | 1 | 8 | 26957 | 680 | 0.025 |
| 26 | 1 | 9 | 26957 | 396 | 0.015 |
| 26 | 1 | 10 | 26957 | 28 | 0.001 |
| 26 | 1 | 11 | 26957 | 0 | 0.000 |
| 27 | 2 | 1 | 30101 | 8070 | 0.268 |
| 27 | 2 | 2 | 30101 | 5522 | 0.183 |
| 27 | 2 | 3 | 30101 | 4389 | 0.146 |
| 27 | 2 | 4 | 30101 | 3653 | 0.121 |
| 27 | 2 | 5 | 30101 | 2917 | 0.097 |
| 27 | 2 | 6 | 30101 | 2039 | 0.068 |
| 27 | 2 | 7 | 30101 | 1331 | 0.044 |
| 27 | 2 | 8 | 30101 | 821 | 0.027 |
| 27 | 2 | 9 | 30101 | 481 | 0.016 |
| 27 | 2 | 10 | 30101 | 311 | 0.010 |
| 27 | 2 | 11 | 30101 | 198 | 0.007 |
| 27 | 2 | 12 | 30101 | 142 | 0.005 |
| 27 | 2 | 13 | 30101 | 85 | 0.003 |
| 27 | 2 | 14 | 30101 | 57 | 0.002 |
| 27 | 2 | 15 | 30101 | 57 | 0.002 |
| 27 | 2 | 16 | 30101 | 28 | 0.001 |
| 27 | 2 | 17 | 30101 | 0 | 0.000 |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well | Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 28 | 4 | 1 | 33782 | 7249 | 0.215 | 30 | 4 | 1 | 37576 | 8212 | 0.219 |
| 28 | 4 | 2 | 33782 | 5522 | 0.163 | 30 | 4 | 2 | 37576 | 6230 | 0.166 |
| 28 | 4 | 3 | 33782 | 4531 | 0.134 | 30 | 4 | 3 | 37576 | 5125 | 0.136 |
| 28 | 4 | 4 | 33782 | 3483 | 0.103 | 30 | 4 | 4 | 37576 | 3908 | 0.104 |
| 28 | 4 | 5 | 33782 | 2775 | 0.082 | 30 | 4 | 5 | 37576 | 3115 | 0.083 |
| 28 | 4 | 6 | 33782 | 2152 | 0.064 | 30 | 4 | 6 | 37576 | 2407 | 0.064 |
| 28 | 4 | 7 | 33782 | 1642 | 0.049 | 30 | 4 | 7 | 37576 | 1869 | 0.050 |
| 28 | 4 | 8 | 33782 | 1303 | 0.039 | 30 | 4 | 8 | 37576 | 1472 | 0.039 |
| 28 | 4 | 9 | 33782 | 1048 | 0.031 | 30 | 4 | 9 | 37576 | 1161 | 0.031 |
| 28 | 4 | 10 | 33782 | 821 | 0.024 | 30 | 4 | 10 | 37576 | 934 | 0.025 |
| 28 | 4 | 11 | 33782 | 651 | 0.019 | 30 | 4 | 11 | 37576 | 736 | 0.020 |
| 28 | 4 | 12 | 33782 | 538 | 0.016 | 30 | 4 | 12 | 37576 | 595 | 0.016 |
| 28 | 4 | 13 | 33782 | 425 | 0.013 | 30 | 4 | 13 | 37576 | 453 | 0.012 |
| 28 | 4 | 14 | 33782 | 311 | 0.009 | 30 | 4 | 14 | 37576 | 368 | 0.010 |
| 28 | 4 | 15 | 33782 | 255 | 0.008 | 30 | 4 | 15 | 37576 | 227 | 0.006 |
| 28 | 4 | 16 | 33782 | 227 | 0.007 | 30 | 4 | 16 | 37576 | 170 | 0.005 |
| 28 | 4 | 17 | 33782 | 170 | 0.005 | 30 | 4 | 17 | 37576 | 142 | 0.004 |
| 28 | 4 | 18 | 33782 | 113 | 0.003 | 30 | 4 | 18 | 37576 | 142 | 0.004 |
| 28 | 4 | 19 | 33782 | 113 | 0.003 | 30 | 4 | 19 | 37576 | 113 | 0.003 |
| 28 | 4 | 20 | 33782 | 85 | 0.003 | 30 | 4 | 20 | 37576 | 57 | 0.002 |
| 28 | 4 | 21 | 33782 | 57 | 0.002 | 30 | 4 | 21 | 37576 | 57 | 0.002 |
| 28 | 4 | 22 | 33782 | 57 | 0.002 | 30 | 4 | 22 | 37576 | 57 | 0.002 |
| 28 | 4 | 23 | 33782 | 57 | 0.002 | 30 | 4 | 23 | 37576 | 57 | 0.002 |
| 28 | 4 | 24 | 33782 | 57 | 0.002 | 30 | 4 | 24 | 37576 | 57 | 0.002 |
| 28 | 4 | 25 | 33782 | 57 | 0.002 | 30 | 4 | 25 | 37576 | 57 | 0.002 |
| 28 | 4 | 26 | 33782 | 57 | 0.002 | 30 | 4 | 26 | 37576 | 28 | 0.001 |
| 28 | 4 | 27 | 33782 | 0 | 0.000 | 30 | 4 | 27 | 37576 | 0 | 0.000 |
| 29 | 2 | 1 | 34320 | 9203 | 0.268 | | | | | | |
| 29 | 2 | 2 | 34320 | 6286 | 0.183 | | | | | | |
| 29 | 2 | 3 | 34320 | 5040 | 0.147 | | | | | | |
| 29 | 2 | 4 | 34320 | 4191 | 0.122 | | | | | | |
| 29 | 2 | 5 | 34320 | 3313 | 0.097 | | | | | | |
| 29 | 2 | 6 | 34320 | 2350 | 0.068 | | | | | | |
| 29 | 2 | 7 | 34320 | 1501 | 0.044 | | | | | | |
| 29 | 2 | 8 | 34320 | 934 | 0.027 | | | | | | |
| 29 | 2 | 9 | 34320 | 566 | 0.017 | | | | | | |
| 29 | 2 | 10 | 34320 | 368 | 0.011 | | | | | | |
| 29 | 2 | 11 | 34320 | 227 | 0.007 | | | | | | |
| 29 | 2 | 12 | 34320 | 142 | 0.004 | | | | | | |
| 29 | 2 | 13 | 34320 | 85 | 0.002 | | | | | | |
| 29 | 2 | 14 | 34320 | 57 | 0.002 | | | | | | |
| 29 | 2 | 15 | 34320 | 57 | 0.002 | | | | | | |
| 29 | 2 | 16 | 34320 | 28 | 0.001 | | | | | | |
| 29 | 2 | 17 | 34320 | 0 | 0.000 | | | | | | |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well | Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | 5 | 1 | 50913 | 11723 | 0.230 | 33 | 6 | 1 | 62750 | 10902 | 0.174 |
| 31 | 5 | 2 | 50913 | 8183 | 0.161 | 33 | 6 | 2 | 62750 | 9118 | 0.145 |
| 31 | 5 | 3 | 50913 | 6400 | 0.126 | 33 | 6 | 3 | 62750 | 7447 | 0.119 |
| 31 | 5 | 4 | 50913 | 5324 | 0.105 | 33 | 6 | 4 | 62750 | 6088 | 0.097 |
| 31 | 5 | 5 | 50913 | 4247 | 0.083 | 33 | 6 | 5 | 62750 | 4870 | 0.078 |
| 31 | 5 | 6 | 50913 | 3341 | 0.066 | 33 | 6 | 6 | 62750 | 4078 | 0.065 |
| 31 | 5 | 7 | 50913 | 2605 | 0.051 | 33 | 6 | 7 | 62750 | 3313 | 0.053 |
| 31 | 5 | 8 | 50913 | 2010 | 0.039 | 33 | 6 | 8 | 62750 | 2690 | 0.043 |
| 31 | 5 | 9 | 50913 | 1501 | 0.029 | 33 | 6 | 9 | 62750 | 2237 | 0.036 |
| 31 | 5 | 10 | 50913 | 1161 | 0.023 | 33 | 6 | 10 | 62750 | 1897 | 0.030 |
| 31 | 5 | 11 | 50913 | 934 | 0.018 | 33 | 6 | 11 | 62750 | 1586 | 0.025 |
| 31 | 5 | 12 | 50913 | 736 | 0.014 | 33 | 6 | 12 | 62750 | 1359 | 0.022 |
| 31 | 5 | 13 | 50913 | 595 | 0.012 | 33 | 6 | 13 | 62750 | 1133 | 0.018 |
| 31 | 5 | 14 | 50913 | 453 | 0.009 | 33 | 6 | 14 | 62750 | 934 | 0.015 |
| 31 | 5 | 15 | 50913 | 340 | 0.007 | 33 | 6 | 15 | 62750 | 793 | 0.013 |
| 31 | 5 | 16 | 50913 | 255 | 0.005 | 33 | 6 | 16 | 62750 | 708 | 0.011 |
| 31 | 5 | 17 | 50913 | 227 | 0.004 | 33 | 6 | 17 | 62750 | 595 | 0.009 |
| 31 | 5 | 18 | 50913 | 198 | 0.004 | 33 | 6 | 18 | 62750 | 510 | 0.008 |
| 31 | 5 | 19 | 50913 | 142 | 0.003 | 33 | 6 | 19 | 62750 | 425 | 0.007 |
| 31 | 5 | 20 | 50913 | 85 | 0.002 | 33 | 6 | 20 | 62750 | 368 | 0.006 |
| 31 | 5 | 21 | 50913 | 57 | 0.001 | 33 | 6 | 21 | 62750 | 311 | 0.005 |
| 31 | 5 | 22 | 50913 | 57 | 0.001 | 33 | 6 | 22 | 62750 | 255 | 0.004 |
| 31 | 5 | 23 | 50913 | 57 | 0.001 | 33 | 6 | 23 | 62750 | 227 | 0.004 |
| 31 | 5 | 24 | 50913 | 57 | 0.001 | 33 | 6 | 24 | 62750 | 198 | 0.003 |
| 31 | 5 | 25 | 50913 | 57 | 0.001 | 33 | 6 | 25 | 62750 | 142 | 0.002 |
| 31 | 5 | 26 | 50913 | 57 | 0.001 | 33 | 6 | 26 | 62750 | 142 | 0.002 |
| 31 | 5 | 27 | 50913 | 57 | 0.001 | 33 | 6 | 27 | 62750 | 113 | 0.002 |
| 31 | 5 | 28 | 50913 | 28 | 0.001 | 33 | 6 | 28 | 62750 | 113 | 0.002 |
| 31 | 5 | 29 | 50913 | 0 | 0.000 | 33 | 6 | 29 | 62750 | 85 | 0.001 |
| | | | | | | 33 | 6 | 30 | 62750 | 85 | 0.001 |
| | | | | | | 33 | 6 | 31 | 62750 | 57 | 0.001 |
| | | | | | | 33 | 6 | 32 | 62750 | 28 | 0.000 |
| | | | | | | 33 | 6 | 33 | 62750 | 0 | 0.000 |

Table A1 cont'd.  Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|
| 32 | 5 | 1 | 55444 | 12771 | 0.230 |
| 32 | 5 | 2 | 55444 | 8948 | 0.161 |
| 32 | 5 | 3 | 55444 | 7023 | 0.127 |
| 32 | 5 | 4 | 55444 | 5805 | 0.105 |
| 32 | 5 | 5 | 55444 | 4644 | 0.084 |
| 32 | 5 | 6 | 55444 | 3681 | 0.066 |
| 32 | 5 | 7 | 55444 | 2832 | 0.051 |
| 32 | 5 | 8 | 55444 | 2180 | 0.039 |
| 32 | 5 | 9 | 55444 | 1642 | 0.030 |
| 32 | 5 | 10 | 55444 | 1274 | 0.023 |
| 32 | 5 | 11 | 55444 | 1019 | 0.018 |
| 32 | 5 | 12 | 55444 | 793 | 0.014 |
| 32 | 5 | 13 | 55444 | 623 | 0.011 |
| 32 | 5 | 14 | 55444 | 481 | 0.009 |
| 32 | 5 | 15 | 55444 | 368 | 0.007 |
| 32 | 5 | 16 | 55444 | 283 | 0.005 |
| 32 | 5 | 17 | 55444 | 227 | 0.004 |
| 32 | 5 | 18 | 55444 | 198 | 0.004 |
| 32 | 5 | 19 | 55444 | 142 | 0.003 |
| 32 | 5 | 20 | 55444 | 85 | 0.002 |
| 32 | 5 | 21 | 55444 | 57 | 0.001 |
| 32 | 5 | 22 | 55444 | 57 | 0.001 |
| 32 | 5 | 23 | 55444 | 57 | 0.001 |
| 32 | 5 | 24 | 55444 | 57 | 0.001 |
| 32 | 5 | 25 | 55444 | 57 | 0.001 |
| 32 | 5 | 26 | 55444 | 57 | 0.001 |
| 32 | 5 | 27 | 55444 | 57 | 0.001 |
| 32 | 5 | 28 | 55444 | 28 | 0.001 |
| 32 | 5 | 29 | 55444 | 0 | 0.000 |

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|
| 34 | 6 | 1 | 65638 | 11242 | 0.171 |
| 34 | 6 | 2 | 65638 | 9514 | 0.145 |
| 34 | 6 | 3 | 65638 | 7759 | 0.118 |
| 34 | 6 | 4 | 65638 | 6343 | 0.097 |
| 34 | 6 | 5 | 65638 | 5097 | 0.078 |
| 34 | 6 | 6 | 65638 | 4247 | 0.065 |
| 34 | 6 | 7 | 65638 | 3455 | 0.053 |
| 34 | 6 | 8 | 65638 | 2832 | 0.043 |
| 34 | 6 | 9 | 65638 | 2350 | 0.036 |
| 34 | 6 | 10 | 65638 | 1982 | 0.030 |
| 34 | 6 | 11 | 65638 | 1642 | 0.025 |
| 34 | 6 | 12 | 65638 | 1416 | 0.022 |
| 34 | 6 | 13 | 65638 | 1161 | 0.018 |
| 34 | 6 | 14 | 65638 | 991 | 0.015 |
| 34 | 6 | 15 | 65638 | 849 | 0.013 |
| 34 | 6 | 16 | 65638 | 736 | 0.011 |
| 34 | 6 | 17 | 65638 | 623 | 0.009 |
| 34 | 6 | 18 | 65638 | 538 | 0.008 |
| 34 | 6 | 19 | 65638 | 425 | 0.006 |
| 34 | 6 | 20 | 65638 | 368 | 0.006 |
| 34 | 6 | 21 | 65638 | 311 | 0.005 |
| 34 | 6 | 22 | 65638 | 283 | 0.004 |
| 34 | 6 | 23 | 65638 | 227 | 0.003 |
| 34 | 6 | 24 | 65638 | 198 | 0.003 |
| 34 | 6 | 25 | 65638 | 170 | 0.003 |
| 34 | 6 | 26 | 65638 | 170 | 0.003 |
| 34 | 6 | 27 | 65638 | 113 | 0.002 |
| 34 | 6 | 28 | 65638 | 113 | 0.002 |
| 34 | 6 | 29 | 65638 | 113 | 0.002 |
| 34 | 6 | 30 | 65638 | 85 | 0.001 |
| 34 | 6 | 31 | 65638 | 85 | 0.001 |
| 34 | 6 | 32 | 65638 | 57 | 0.001 |
| 34 | 6 | 33 | 65638 | 57 | 0.001 |
| 34 | 6 | 34 | 65638 | 57 | 0.001 |
| 34 | 6 | 35 | 65638 | 28 | 0.000 |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well | Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 35 | 7 | 1 | 78437 | 17981 | 0.229 | 36 | 7 | 1 | 93671 | 21492 | 0.229 |
| 35 | 7 | 2 | 78437 | 13734 | 0.175 | 36 | 7 | 2 | 93671 | 16452 | 0.176 |
| 35 | 7 | 3 | 78437 | 10704 | 0.136 | 36 | 7 | 3 | 93671 | 12799 | 0.137 |
| 35 | 7 | 4 | 78437 | 8297 | 0.106 | 36 | 7 | 4 | 93671 | 9911 | 0.106 |
| 35 | 7 | 5 | 78437 | 6371 | 0.081 | 36 | 7 | 5 | 93671 | 7645 | 0.082 |
| 35 | 7 | 6 | 78437 | 4927 | 0.063 | 36 | 7 | 6 | 93671 | 5890 | 0.063 |
| 35 | 7 | 7 | 78437 | 3709 | 0.047 | 36 | 7 | 7 | 93671 | 4446 | 0.047 |
| 35 | 7 | 8 | 78437 | 2832 | 0.036 | 36 | 7 | 8 | 93671 | 3370 | 0.036 |
| 35 | 7 | 9 | 78437 | 2152 | 0.027 | 36 | 7 | 9 | 93671 | 2577 | 0.028 |
| 35 | 7 | 10 | 78437 | 1642 | 0.021 | 36 | 7 | 10 | 93671 | 1954 | 0.021 |
| 35 | 7 | 11 | 78437 | 1246 | 0.016 | 36 | 7 | 11 | 93671 | 1501 | 0.016 |
| 35 | 7 | 12 | 78437 | 963 | 0.012 | 36 | 7 | 12 | 93671 | 1133 | 0.012 |
| 35 | 7 | 13 | 78437 | 736 | 0.009 | 36 | 7 | 13 | 93671 | 878 | 0.009 |
| 35 | 7 | 14 | 78437 | 566 | 0.007 | 36 | 7 | 14 | 93671 | 708 | 0.008 |
| 35 | 7 | 15 | 78437 | 481 | 0.006 | 36 | 7 | 15 | 93671 | 566 | 0.006 |
| 35 | 7 | 16 | 78437 | 396 | 0.005 | 36 | 7 | 16 | 93671 | 481 | 0.005 |
| 35 | 7 | 17 | 78437 | 340 | 0.004 | 36 | 7 | 17 | 93671 | 368 | 0.004 |
| 35 | 7 | 18 | 78437 | 283 | 0.004 | 36 | 7 | 18 | 93671 | 311 | 0.003 |
| 35 | 7 | 19 | 78437 | 227 | 0.003 | 36 | 7 | 19 | 93671 | 227 | 0.002 |
| 35 | 7 | 20 | 78437 | 198 | 0.003 | 36 | 7 | 20 | 93671 | 198 | 0.002 |
| 35 | 7 | 21 | 78437 | 142 | 0.002 | 36 | 7 | 21 | 93671 | 170 | 0.002 |
| 35 | 7 | 22 | 78437 | 142 | 0.002 | 36 | 7 | 22 | 93671 | 170 | 0.002 |
| 35 | 7 | 23 | 78437 | 113 | 0.001 | 36 | 7 | 23 | 93671 | 113 | 0.001 |
| 35 | 7 | 24 | 78437 | 57 | 0.001 | 36 | 7 | 24 | 93671 | 57 | 0.001 |
| 35 | 7 | 25 | 78437 | 57 | 0.001 | 36 | 7 | 25 | 93671 | 57 | 0.001 |
| 35 | 7 | 26 | 78437 | 57 | 0.001 | 36 | 7 | 26 | 93671 | 57 | 0.001 |
| 35 | 7 | 27 | 78437 | 28 | 0.000 | 36 | 7 | 27 | 93671 | 57 | 0.001 |
| 35 | 7 | 28 | 78437 | 28 | 0.000 | 36 | 7 | 28 | 93671 | 57 | 0.001 |
| 35 | 7 | 29 | 78437 | 28 | 0.000 | 36 | 7 | 29 | 93671 | 28 | 0.000 |
| 35 | 7 | 30 | 78437 | 0 | 0.000 | 36 | 7 | 30 | 93671 | 0 | 0.000 |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well | Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 37 | 1 | 1 | 129407 | 19652 | 0.152 | 38 | 1 | 1 | 135013 | 20473 | 0.152 |
| 37 | 1 | 2 | 129407 | 26476 | 0.205 | 38 | 1 | 2 | 135013 | 27637 | 0.205 |
| 37 | 1 | 3 | 129407 | 20331 | 0.157 | 38 | 1 | 3 | 135013 | 21209 | 0.157 |
| 37 | 1 | 4 | 129407 | 15914 | 0.123 | 38 | 1 | 4 | 135013 | 16622 | 0.123 |
| 37 | 1 | 5 | 129407 | 13054 | 0.101 | 38 | 1 | 5 | 135013 | 13620 | 0.101 |
| 37 | 1 | 6 | 129407 | 9175 | 0.071 | 38 | 1 | 6 | 135013 | 9571 | 0.071 |
| 37 | 1 | 7 | 129407 | 7107 | 0.055 | 38 | 1 | 7 | 135013 | 7447 | 0.055 |
| 37 | 1 | 8 | 129407 | 4899 | 0.038 | 38 | 1 | 8 | 135013 | 5097 | 0.038 |
| 37 | 1 | 9 | 129407 | 3851 | 0.030 | 38 | 1 | 9 | 135013 | 4049 | 0.030 |
| 37 | 1 | 10 | 129407 | 2803 | 0.022 | 38 | 1 | 10 | 135013 | 2917 | 0.022 |
| 37 | 1 | 11 | 129407 | 1926 | 0.015 | 38 | 1 | 11 | 135013 | 2010 | 0.015 |
| 37 | 1 | 12 | 129407 | 1472 | 0.011 | 38 | 1 | 12 | 135013 | 1557 | 0.012 |
| 37 | 1 | 13 | 129407 | 708 | 0.005 | 38 | 1 | 13 | 135013 | 708 | 0.005 |
| 37 | 1 | 14 | 129407 | 453 | 0.004 | 38 | 1 | 14 | 135013 | 425 | 0.003 |
| 37 | 1 | 15 | 129407 | 340 | 0.003 | 38 | 1 | 15 | 135013 | 340 | 0.003 |
| 37 | 1 | 16 | 129407 | 311 | 0.002 | 38 | 1 | 16 | 135013 | 311 | 0.002 |
| 37 | 1 | 17 | 129407 | 227 | 0.002 | 38 | 1 | 17 | 135013 | 255 | 0.002 |
| 37 | 1 | 18 | 129407 | 142 | 0.001 | 38 | 1 | 18 | 135013 | 170 | 0.001 |
| 37 | 1 | 19 | 129407 | 142 | 0.001 | 38 | 1 | 19 | 135013 | 170 | 0.001 |
| 37 | 1 | 20 | 129407 | 113 | 0.001 | 38 | 1 | 20 | 135013 | 113 | 0.001 |
| 37 | 1 | 21 | 129407 | 113 | 0.001 | 38 | 1 | 21 | 135013 | 113 | 0.001 |
| 37 | 1 | 22 | 129407 | 85 | 0.001 | 38 | 1 | 22 | 135013 | 85 | 0.001 |
| 37 | 1 | 23 | 129407 | 57 | 0.000 | 38 | 1 | 23 | 135013 | 57 | 0.000 |
| 37 | 1 | 24 | 129407 | 28 | 0.000 | 38 | 1 | 24 | 135013 | 57 | 0.000 |
| 37 | 1 | 25 | 129407 | 28 | 0.000 | 38 | 1 | 25 | 135013 | 0 | 0.000 |
| 37 | 1 | 26 | 129407 | 0 | 0.000 | | | | | | |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well | Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 39 | 2 | 1 | 144924 | 34433 | 0.238 | 40 | 2 | 1 | 152003 | 36160 | 0.238 |
| 39 | 2 | 2 | 144924 | 23220 | 0.160 | 40 | 2 | 2 | 152003 | 24409 | 0.161 |
| 39 | 2 | 3 | 144924 | 17415 | 0.120 | 40 | 2 | 3 | 152003 | 18293 | 0.120 |
| 39 | 2 | 4 | 144924 | 13365 | 0.092 | 40 | 2 | 4 | 152003 | 14045 | 0.092 |
| 39 | 2 | 5 | 144924 | 10760 | 0.074 | 40 | 2 | 5 | 152003 | 11298 | 0.074 |
| 39 | 2 | 6 | 144924 | 8637 | 0.060 | 40 | 2 | 6 | 152003 | 9090 | 0.060 |
| 39 | 2 | 7 | 144924 | 7192 | 0.050 | 40 | 2 | 7 | 152003 | 7561 | 0.050 |
| 39 | 2 | 8 | 144924 | 5862 | 0.040 | 40 | 2 | 8 | 152003 | 6145 | 0.040 |
| 39 | 2 | 9 | 144924 | 4786 | 0.033 | 40 | 2 | 9 | 152003 | 4984 | 0.033 |
| 39 | 2 | 10 | 144924 | 3794 | 0.026 | 40 | 2 | 10 | 152003 | 3964 | 0.026 |
| 39 | 2 | 11 | 144924 | 3058 | 0.021 | 40 | 2 | 11 | 152003 | 3200 | 0.021 |
| 39 | 2 | 12 | 144924 | 2435 | 0.017 | 40 | 2 | 12 | 152003 | 2577 | 0.017 |
| 39 | 2 | 13 | 144924 | 2039 | 0.014 | 40 | 2 | 13 | 152003 | 2124 | 0.014 |
| 39 | 2 | 14 | 144924 | 1586 | 0.011 | 40 | 2 | 14 | 152003 | 1642 | 0.011 |
| 39 | 2 | 15 | 144924 | 1246 | 0.009 | 40 | 2 | 15 | 152003 | 1303 | 0.009 |
| 39 | 2 | 16 | 144924 | 1048 | 0.007 | 40 | 2 | 16 | 152003 | 1104 | 0.007 |
| 39 | 2 | 17 | 144924 | 821 | 0.006 | 40 | 2 | 17 | 152003 | 878 | 0.006 |
| 39 | 2 | 18 | 144924 | 680 | 0.005 | 40 | 2 | 18 | 152003 | 708 | 0.005 |
| 39 | 2 | 19 | 144924 | 595 | 0.004 | 40 | 2 | 19 | 152003 | 595 | 0.004 |
| 39 | 2 | 20 | 144924 | 453 | 0.003 | 40 | 2 | 20 | 152003 | 453 | 0.003 |
| 39 | 2 | 21 | 144924 | 340 | 0.002 | 40 | 2 | 21 | 152003 | 340 | 0.002 |
| 39 | 2 | 22 | 144924 | 283 | 0.002 | 40 | 2 | 22 | 152003 | 255 | 0.002 |
| 39 | 2 | 23 | 144924 | 227 | 0.002 | 40 | 2 | 23 | 152003 | 255 | 0.002 |
| 39 | 2 | 24 | 144924 | 198 | 0.001 | 40 | 2 | 24 | 152003 | 198 | 0.001 |
| 39 | 2 | 25 | 144924 | 142 | 0.001 | 40 | 2 | 25 | 152003 | 170 | 0.001 |
| 39 | 2 | 26 | 144924 | 113 | 0.001 | 40 | 2 | 26 | 152003 | 113 | 0.001 |
| 39 | 2 | 27 | 144924 | 113 | 0.001 | 40 | 2 | 27 | 152003 | 57 | 0.000 |
| 39 | 2 | 28 | 144924 | 57 | 0.000 | 40 | 2 | 28 | 152003 | 57 | 0.000 |
| 39 | 2 | 29 | 144924 | 28 | 0.000 | 40 | 2 | 29 | 152003 | 28 | 0.000 |
| 39 | 2 | 30 | 144924 | 0 | 0.000 | 40 | 2 | 30 | 152003 | 0 | 0.000 |

Table A1 cont'd. Gas production profiles from representative wells by PSAC region.

| Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well | Curve # | PSAC Region | time years | Total Flow over Well Life 1000 m3 | Gas Flow 1000 m3 | Proportion of Flow over Life of Well |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 41 | 1 | 1 | 462976 | 72717 | 0.157 | 42 | 1 | 1 | 477276 | 74982 | 0.157 |
| 41 | 1 | 2 | 462976 | 71216 | 0.154 | 42 | 1 | 2 | 477276 | 73425 | 0.154 |
| 41 | 1 | 3 | 462976 | 61900 | 0.134 | 42 | 1 | 3 | 477276 | 63826 | 0.134 |
| 41 | 1 | 4 | 462976 | 49327 | 0.107 | 42 | 1 | 4 | 477276 | 50857 | 0.107 |
| 41 | 1 | 5 | 462976 | 38482 | 0.083 | 42 | 1 | 5 | 477276 | 39672 | 0.083 |
| 41 | 1 | 6 | 462976 | 30072 | 0.065 | 42 | 1 | 6 | 477276 | 31007 | 0.065 |
| 41 | 1 | 7 | 462976 | 25145 | 0.054 | 42 | 1 | 7 | 477276 | 25938 | 0.054 |
| 41 | 1 | 8 | 462976 | 21492 | 0.046 | 42 | 1 | 8 | 477276 | 22172 | 0.046 |
| 41 | 1 | 9 | 462976 | 17528 | 0.038 | 42 | 1 | 9 | 477276 | 18066 | 0.038 |
| 41 | 1 | 10 | 462976 | 14272 | 0.031 | 42 | 1 | 10 | 477276 | 14725 | 0.031 |
| 41 | 1 | 11 | 462976 | 11723 | 0.025 | 42 | 1 | 11 | 477276 | 12091 | 0.025 |
| 41 | 1 | 12 | 462976 | 9741 | 0.021 | 42 | 1 | 12 | 477276 | 10052 | 0.021 |
| 41 | 1 | 13 | 462976 | 8042 | 0.017 | 42 | 1 | 13 | 477276 | 8297 | 0.017 |
| 41 | 1 | 14 | 462976 | 6513 | 0.014 | 42 | 1 | 14 | 477276 | 6711 | 0.014 |
| 41 | 1 | 15 | 462976 | 5493 | 0.012 | 42 | 1 | 15 | 477276 | 5663 | 0.012 |
| 41 | 1 | 16 | 462976 | 4361 | 0.009 | 42 | 1 | 16 | 477276 | 4502 | 0.009 |
| 41 | 1 | 17 | 462976 | 3653 | 0.008 | 42 | 1 | 17 | 477276 | 3766 | 0.008 |
| 41 | 1 | 18 | 462976 | 2945 | 0.006 | 42 | 1 | 18 | 477276 | 3030 | 0.006 |
| 41 | 1 | 19 | 462976 | 2209 | 0.005 | 42 | 1 | 19 | 477276 | 2265 | 0.005 |
| 41 | 1 | 20 | 462976 | 1586 | 0.003 | 42 | 1 | 20 | 477276 | 1614 | 0.003 |
| 41 | 1 | 21 | 462976 | 1218 | 0.003 | 42 | 1 | 21 | 477276 | 1246 | 0.003 |
| 41 | 1 | 22 | 462976 | 793 | 0.002 | 42 | 1 | 22 | 477276 | 821 | 0.002 |
| 41 | 1 | 23 | 462976 | 680 | 0.001 | 42 | 1 | 23 | 477276 | 736 | 0.002 |
| 41 | 1 | 24 | 462976 | 595 | 0.001 | 42 | 1 | 24 | 477276 | 623 | 0.001 |
| 41 | 1 | 25 | 462976 | 453 | 0.001 | 42 | 1 | 25 | 477276 | 481 | 0.001 |
| 41 | 1 | 26 | 462976 | 255 | 0.001 | 42 | 1 | 26 | 477276 | 255 | 0.001 |
| 41 | 1 | 27 | 462976 | 227 | 0.000 | 42 | 1 | 27 | 477276 | 227 | 0.000 |
| 41 | 1 | 28 | 462976 | 198 | 0.000 | 42 | 1 | 28 | 477276 | 198 | 0.000 |
| 41 | 1 | 29 | 462976 | 113 | 0.000 | 42 | 1 | 29 | 477276 | 28 | 0.000 |
| 41 | 1 | 30 | 462976 | 28 | 0.000 | 42 | 1 | 30 | 477276 | 0 | 0.000 |
| 41 | 1 | 31 | 462976 | 0 | 0.000 | | | | | | |

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