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Abstract: It is increasingly important to provide the relevant data for strategic decisions related to oil production and the marketing of oil products. We propose the use of a forecasting model to define a production profile for the Canadian oil sector to 2050. Our approach considers both economic variables (prices) and physical variables (production and infrastructure) by establishing a link between well count, oil price, and oil production. Our methodology is based on practices developed in the oil industry. Indeed, the well count is used as a key component of planning and decision-making in matters such as capital and operational expenditures. We combine our approach with the Hubbert logistic function to take into account the impact of the age of the producing wells. We calibrate our forecasting model using a Canadian database of historical production data. The records come from the Eastern Canada offshore and Canadian oil sands projects that are of growing importance in the national oil production. We test our model under a particular scenario for oil prices, including an extrapolation of the historical price trends. Our results show the evolution of oil production and indicate when peak production is achieved for each of the oil sources considered.

Key Words: Forecasting, Hubbert, Well Count, Oil production, Oil prices, Oil reserves, Oil sands, Onshore, Offshore, Infrastructure.

1 Introduction

Given the complexity of oil markets, there is an ongoing need to create more accurate and reliable models to explain and predict evolutions in oil production, regulations, and prices. The models are necessarily simplified representations that aim to reflect real-world tendencies.

The estimation and forecasting of recoverable oil is difficult because reserves can vary from one year (and one source) to the next depending on technological, economic, and political considerations. Technological improvements reduce costs and increase access to resources that were not available before. Likewise, a better economic environment stimulates the energy demand, yielding higher oil prices that make more expensive projects profitable. Reserve data is also important for governments and companies because this information gives access to production quotas, as in the OPEC case, or to financing resources because the value of the fields is related to the reserves. BP (British Petroleum) reports illustrate these variations for 2006 and 2010: (BP, 2006) assesses Canadian proven reserves for 2006 at 17.1 million barrels per day (MMbpd), while (BP, 2010) assesses the value for the same year at 27.6 MMbpd, with a further increase to 32.1 MMbpd for 2010. Note that the economic and technological dimensions of the reserves are easier to model than the political dimension. In particular, the technological aspect can be modelled using the cumulative stock (Holland, 2008), and the economic aspect is related to the concept of the supply curve (Besanko and Braeutigam, 2011).

This article considers in particular unconventional oil and offshore production. The former category consists of extra-heavy crude oil, oil sands, and oil shale. These unconventional oil sources are more labour-intensive to produce, require extra energy to refine, have higher production costs, and are often in remote locations. Additionally, they present other problems such as higher greenhouse gas (GHG) emissions (up to three times more GHG emissions per barrel than conventional sources (Arsenault, 2008; Charpentier, Bergerson, and MacLean , 2009)), waste management issues, and water usage issues. This article also considers offshore production, which is mostly light oil, because of its recent growth and the challenges associated with such technological development. The exploitation is more complex because of the remote locations. Additionally, offshore developments present a risk of ecological disasters, such as the one that occurred in the Gulf of Mexico in 2010. All these factors have contributed to the postponement of unconventional oil exploitation. However, the transformation experienced by oil markets, mainly significantly higher price levels, now permits the development of these expensive resources. Three of the key unconventional sources for large-scale production are the extra-heavy oil in the Orinoco Belt of Venezuela, the oil sands in the Western Canada Sedimentary Basin (WCSB), and the oil shale of the Green River Formation in Colorado, Utah, and Wyoming in the United States.

Canada is an important energy producer, in the sixth position globally; the United States is the main consumer of Canadian energy products (BP, 2010). In 2008 Canadian oil production was led by Alberta, which produced approximately 67% of the total, while Eastern Offshore production represented approximately 13% (Canadian Association of Petroleum Producers (CAPP), 2009). Over the last 10 years, Alberta's production share has decreased by 6%, while Eastern Offshore production increased by 10% between 1998 and 2008 (CAPP, 2009). Despite these changes, Western Canada (British Columbia, Alberta, Saskatchewan, and Manitoba) continues to lead oil production with a share of approximately 86% (CAPP, 2009). In parallel, there has been a decrease in the share of conventional oil: conventional production accounted for 74% of the total in 1998, and 53% in 2008 (a decrease of approximately 20%) (CAPP, 2009). Thus, the decline in the percentage of conventional energy sources runs parallel with an increase in unconventional sources. In particular, oil sands production has experienced significant growth, rising from 26% of the total in 1998 to 47% in 2008 (CAPP, 2009). Considering the oil production by province and by source reveals an interesting new trend for Canada's oil production. The leading new developments in the last ten years are the Western oil sands (with an increase of 20%) and the Eastern offshore (with an increase of 10%). To summarize, as conventional oil production declines, there is a corresponding increase in crude oil produced from oil sands and offshore developments. What about the future? More precisely, what changes can be expected in the future in the Canadian oil sector and the evolution of conventional and unconventional sources?

To address this question, we combine two approaches. First, we use a forecasting approach based on the correlation of oil production and price to predict the annual well count (i.e., the new wells drilled each year). Second, we use the logistic function of the Hubbert approach (Hubbert, 1956) to empirically explain the decay in oil production. The Hubbert curve improves the forecasting approach by taking into account the depletion characteristic of oil resources according to their installed capacity. In addition, the forecasting approach complements the Hubbert approach by accounting for the necessary investment. The overall approach corresponds to a combination of physical and economic variables in an original model that allows us to analyze the evolution of the Canadian oil sector and its economic implications under different scenarios.

Traditional forecasting models use past data to determine historical trends that predict future behaviour. These models are commonly used to create a "business as usual" (BAU) scenario. Brandt (2010) describes several approaches to forecasting oil production: Hubbert's logistic model (Hubbert, 1956), the system simulation model (Sterman and Richardson, 1985), bottom-up models (Bentley and Boyle, 2007), and economic models (Hotelling, 1931; Nordhaus, 1973; Kaufmann and Cleveland, 2001; Holland, 2008)]. We will describe the economic models in more detail. Hotelling (1931) asserts that if there is an optimal and efficient extraction path over time, the value of the non-renewable resource must be rising at the interest rate. In other words, the (discounted) shadow price of the resource stock, which can be considered as an economic measure of the resource scarcity, should grow at the interest rate. Nordhaus (1973) focuses on the whole energy market and looks for the minimum discounted costs to meet demand, assuming competitive suppliers operating in a competitive market. Alternatively, Holland (2008) presents four Hotelling-style models evaluating different situations such as demand shift and technological change while analyzing peaks in oil production. Finally, Kaufmann and Cleveland (2001) apply the Hubbert model to predict oil production using differences between the predicted and actual values as input for the calibration of an econometric model with economic and policy variables.

However, these approaches do not deal with the combined problem of pricing, production, and infrastructure. In this article, we do so by developing a bottom-up model based on well count (or production assets), where this count represents the main connector between oil production and oil price. We estimate the parameters via linear regression. Our model allows us to explain well-count evolution according to oil production and oil price, under the assumption that there is a linear relationship between the dependent variable (well count) and the independent variables (production and price). This linear relationship is the result of microeconomic assumptions that define a perfect competitive market, where one can postulate an upward relationship between the market price and the quantity produced at a specific time (Besanko and Braeutigam, 2011). We apply a Hubbert logistic model looking at the most basic level of oil production (i.e., the well count). Our approach differs from other multi-cycle Hubbert logistic models, which usually consider the field level, looking at two or three cycles. Cycles are changes in the parameters due to new production or discovery conditions. For example, cycles in production relate to conventional production versus enhanced oil recovery, and cycles in discovery relate to the type of field such as oil sands, shale oil, or deepwater exploration (Laherrére, 2000). In our case, although we are not explicitly dealing with a multi-cycle approach, we are implicitly considering cycles through investments. Furthermore, we are able to simulate the maturity of a field by modifying the production level of each year's well count according to the age of the field.

We apply our approach to the Canadian oil sector. More precisely, we generate numerical results for a BAU development of the Canadian oil sector. We analyze the results and compare them to predictions from different sources (Söderbergh, Robelius, and Aleklett, 2005; National Energy Board of Canada (NEB), 2007; CAPP, 2009).

The remainder of this paper is organized as follows. In Section 2, we present our model and describe how it is calibrated. Section 3 discusses our numerical results, and Section 4 provides concluding remarks.

2 Modelling Approach

Our model aims to guide oil production planning using a forecast that links well count, oil price, and oil production. More precisely, we first use a forecast based on a linear regression model to predict the well count. We then consider the decay in oil production using a Hubbert logistic curve. This enables us to predict the oil production and well count under different oil-price scenarios.

For a company exploiting an oil field, a well is the basic production unit. Called a "producing asset," its production decreases over time as the corresponding non-renewable resource is exploited. In a given oil field, the initial production of an individual well is determined by the oil field's age. Specifically, in a new oil field, the production rate per well will initially increase when a new well is drilled. Conversely, in a mature oil field, the production rate per well will decrease when a new well is drilled.

2.1 Model

We assume that yearly production of oil ($P_{o,n}$) of a given oil type o (e.g., onshore, offshore, or oil sands) in a given field or region n is a linear function of the new investments ($I_{o,n}$) that correspond to the number of newly drilled wells (the well count); the field average production rate ($f_{o,n}$) per well; the time-indexed performance (production) for individual wells ($w_{o,n}$), which is assumed to be identical for the new wells drilled in a given year (as a vintage); and the average life ($l_{o,n}$) of the assets (wells), as follows:

$$P_{o,n}(t) = \sum_{i=t-l_{o,n}}^{t} \left(I_{o,n}\left(i\right).f_{o,n}\left(i\right).w_{o,n}(t-i) \right) \tag{1}$$

where t is a (discrete) time index corresponding to the year considered. Note that the field average production rate ($f_{o,n}$) could be either a constant (average production) or a function of time or the quantity produced. In the latter case, it could account for learning effects (improving with time or as more oil is produced). It can also represent the maturity of the oil field.

Let us now detail the investment in new wells ($I_{o,n}$). Under some (strong) microeconomic assumptions (Jukić, Scitovski, and Sabo, 2005) that define a perfect competitive market (such as perfect information, a large number of buyers and sellers, free entry and exit, homogeneous goods, perfect factor mobility, and zero transaction costs), one can postulate an upward relationship between oil price (p) and the production ($P_{o,n}$) at time t. We assume here that the new investments follow this rationale as described below:

$$I_{o,n}(t) = k_o + k_1.p(t) + k_2.P_{o,n}(t) \tag{2}$$

where k_0, k_1, and k_2 are calibration parameters.

Equations (1) and (2) are based on supplier behaviour according to specific microeconomic principles as well as practices in the oil industry. More precisely, oil-producing firms typically use an approach similar to Eq. (2) as a planning tool to help them decide what new wells to drill. In this case, the price and production levels (to be used in Eq. (2)) are based on expert estimations. We have statistically tested the correlation between oil prices and well counts for Canada; see Section 3.

We now discuss the performance of individual wells ($w_{o,n}$). To predict the future oil production, we use the Hubert peak approach that uses a logistic function to explain the decline in the production of oil wells and fields over time (Hubbert, 1956). This function is based on empirical observations made by the American geophysicist M. King Hubbert as he successfully predicted the evolution of American oil production around 1965–1970. It can be expressed as follows:

$$w_{o,n}(t) = \frac{p_0 \cdot e^{-p_1 \cdot t}}{\left(p_2 + p_3 \cdot e^{-p_4 \cdot t}\right)^2} \tag{3}$$

where $p_0, \ldots, p_4$ are calibration parameters, adjusted to match the total production for a specific oil type and region.

The next section details how we calibrate our model for Canadian oil production.

2.2 Calibration

2.2.1 Calibration procedure

We have calibrated our model for the different types of oil production (conventional onshore, offshore, and oil sands) for two regions (Eastern and Western Canada) for the period 1980–2007. The calibration procedure has two steps. First, parameters k from Eq. (2) and p from Eq. (3) are estimated to match the historical well-count levels using estimations of price and production. However, this calibration does not precisely match the historical production level. A second iteration is necessary, to produce new estimates for the parameters k that will be used only to forecast production levels (and reserve levels, as discussed in Section 3.3).

Step 1 (parameter calibration for well-count estimation):

Parameters k_0, k_1, and k_2 from Eq. (2) are estimated using a multiple linear regression. The prices (p) are the annual average market prices of West Texas Intermediate (WTI) (U.S. Energy Information Administration (EIA), 2011). Note that until 2007 WTI was routinely used as an oil-price reference for North America. The production levels ($P_{o,n}$) are chronological values for the total oil production for the specific type and region considered (CAPP, 2009). The investment values are chronological values for newly drilled wells (CAPP, 2009; BP, 2010). The values $f_{o,n}$ are available for the period 1980–2007 for which the calibration is performed (CAPP, 2009; BP, 2010). The parameters p_0, p_1, p_2, p_3, and p_4 from Eq. (3) are estimated via a multiple nonlinear regression on Eq. (1).

When we use the above estimates for k and p to compute (following Eq. (1)) the predicted production levels, we find that the levels do not exactly match the observed historical values. Indeed, as already explained, oil firms do not base their future investment decisions on prices and production levels (that cannot be observed) but on an expert estimation of these values. Hence, Eqs. (1) and (2) cannot precisely reproduce past investment decisions. To overcome this difficulty, we propose a second calibration for the parameters k to be used only when forecasting oil-production levels.

Step 2 (revised calibration for oil-production estimation):

Let k_i^1 be the parameter estimate from step 1, and let $I_{o,n}^1$ and $P_{o,n}^1$ be the values of the well count and production computed using this estimate. Similarly, let k_i^2 be the parameter estimate to be obtained during step 2, and let $I_{o,n}^2$ and $P_{o,n}^2$ be the values to be computed using the new estimate. Let $\overline{P_{o,n}}$ be the observed historical values for the calibration period (1980–2007).

To calibrate $P_{o,n}^2$, we use a weighted least squares approach (Kiers H.A.L., 1997). The idea is to minimize the (weighted) error between the observed production ($\overline{P_{o,n}}$) and the predicted production ($P_{o,n}^2$) while keeping the new predicted well count ($I_{o,n}^2$) close to the count ($I_{o,n}^1$) calibrated in step 1.

2.2.2 Calibration results

As an illustration, we present the results of our calibration for the Canadian onshore oil production, for which long-term historical data are available (CAPP, 2009). Onshore oil fields are mature, so the production rates are decreasing over time. Figure 1 presents the estimated well count versus the actual count, together with the 95% confidence interval curves.

Figure 1 reveals that there is a good agreement between the estimated and actual values. We have also verified that the results are statistically significant by performing a series of tests. The student test yields values of 8.04 for production and 14.12 for price (for 13 observations the values should be higher than 2.02). The P-values are around 10-6 for production and 10-8 for price. The adjusted R-square is 0.91, indicating a strong linear correlation between our dependent variable (well count) and the independent variables (WTI and oil production). Finally, the Fisher test indicates that the variance of the dependent variable explained by the model is approximately 988 times higher than the unexplained variance.

Figure 2 shows the contribution of each input variable (production and price) to the well count, resulting from the linear regression of Step 1 of the calibration.

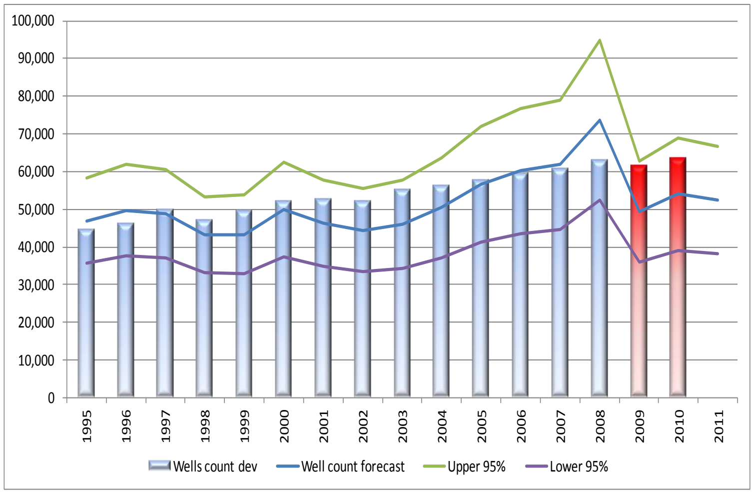

Figure 1: Comparison of the estimated and actual well count (actual data from CAPP (2009)).

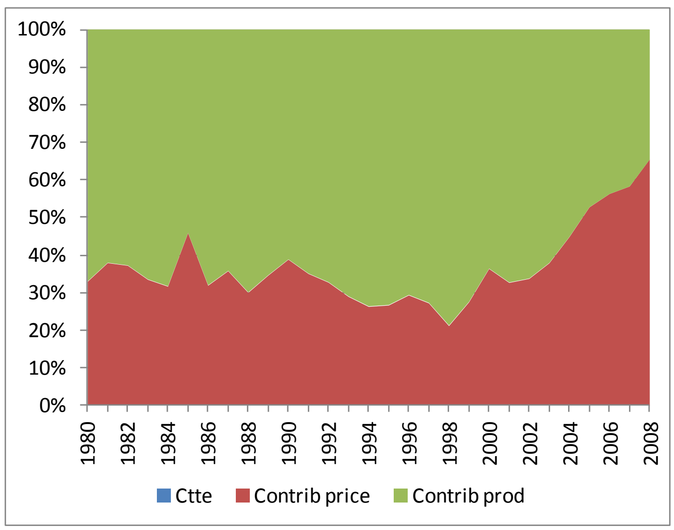

Figure 2: Contribution of each input to well count.

As expected, Fig. 2 reveals that production is the main driver of well count, but as the price increases, its contribution becomes more significant. A possible explanation for this is that higher prices may fuel speculation. This would be similar to the behaviour observed in the stock market, where traders show a positive feedback for future purchases in response to today's price increase (De Long, Shleifer, Summers and Waldmann, 1990). This result helps to justify the use of two calibration steps, the first based on expected market values and the second linked to real production values.

To estimate the field average production rate per well ($f_{o,n}$), we divide the annual total production by the well count and perform a linear regression. Figure 3 illustrates this linear fit for Canadian onshore production.

As expected, Fig. 3 reveals that the oil production for each new well decreases since the oil field is depleting. Such a linear fit is appropriate for a mature oil field. In the case of a new field (oil sands) we have adjusted the linear trend to capture the change from an increasing to a decreasing rate. A more sophisticated approach would be to use a Hubbert logistic function to capture this change.

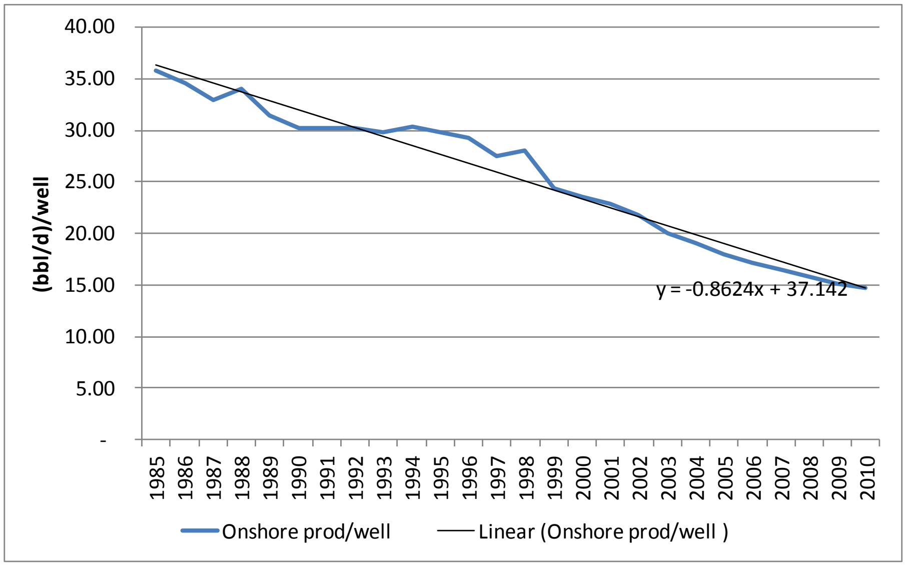

Figure 3: Linear trend for unitary well production in onshore Canada (actual data from CAPP (2009)).

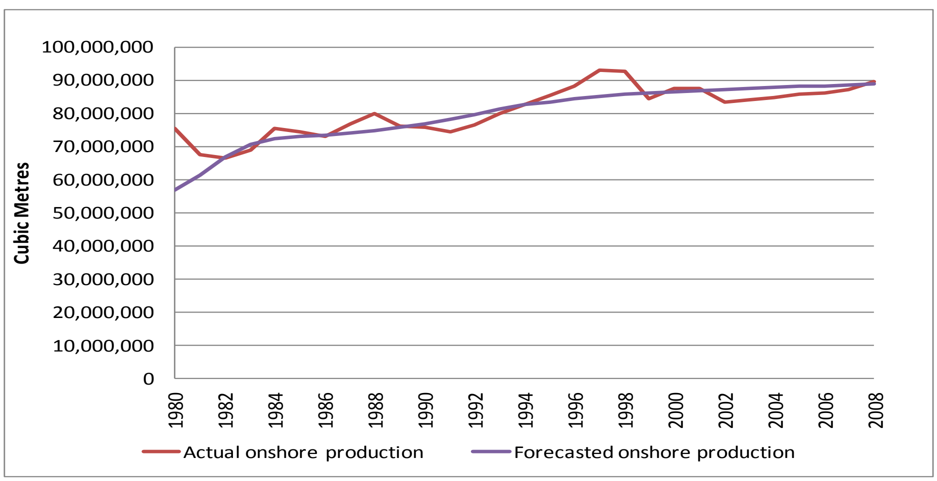

Figure 4: Results from the curve fitting model (actual data from CAPP (2009)).

Figure 4 presents the final fit for the onshore oil production after the second calibration step. In this figure, the actual production data come from the CAPP report (2009).

Figure 4 shows a good agreement between the estimated and actual onshore production. Additionally, various tests show that the results are statistically significant. The student test yields a value of 91.82 (for 29 observations the value should be higher than 2.045). The P-values are around 10-36. The adjusted R-square is 0.96, indicating a strong linear correlation between the forecast and observed production. Finally, the Fisher test indicates that the variance of the dependent variable explained by the model is approximately 8431 times higher than the unexplained variance.

3 Numerical Results

In this section, we apply our methodology to forecast the Canadian offshore and oil sands production for newer oil fields (CAPP, 2009). The production rates initially increase over time and then start to decrease as the fields become mature. We must also predict the inflection point.

3.1 Offshore oil production

The reports from the Canada–Nova Scotia Offshore Petroleum Board [Canada–Nova Scotia Offshore Petroleum Board (CNSOPB), 2010] and the Canada–Newfoundland and Labrador Offshore Petroleum Board [Canada–Newfoundland and Labrador Offshore Petroleum Board (CNLOPB), 2010] contain detailed information about the Eastern Canada offshore projects. This includes the oil production by well and the production profiles. It allows us to forecast the overall production and the well count (new wells to be drilled); our results are reported in Figs. 5 and 6. We have prepared these results by splitting the total production (as estimated by our model) between the different offshore projects (that are either ongoing or announced by the industry, (CNSOPB, 2010; CNLNPB, 2010)). It is important to categorize production trends by project and water-depth because the production costs are directly correlated with these factors. In Fig. 5, the total production is allocated to three different water-depth categories. The categories correspond to those used by the industry: 0–300 ft (shallow water), 300–400 ft (deep-water) and 400–1000 ft (ultra-deep water).

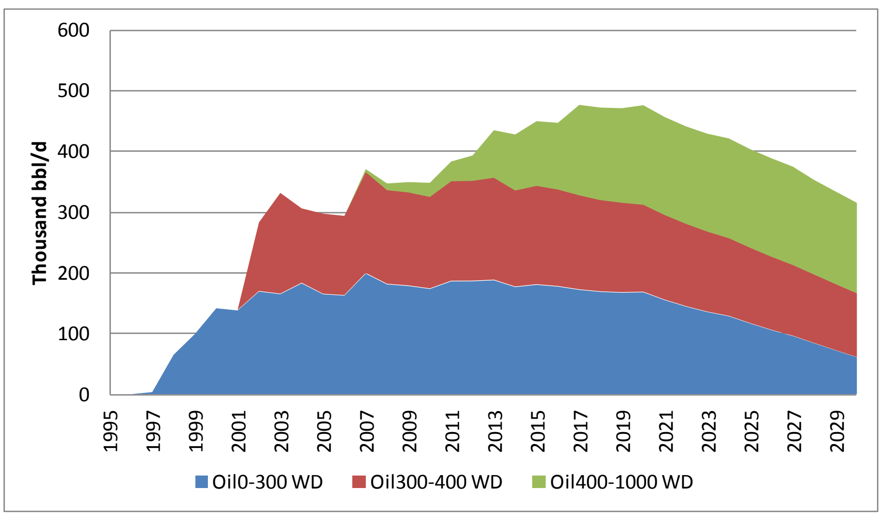

Figure 5: Forecast of the offshore oil production in Eastern Canada considering production by water depth.

Figure 6 reports the well count together with the production split between specific projects (ongoing and announced). Note that the difference between the total production forecast by our model and the total production of all the specific projects (Hibernia, White Rose, Terra Nova, Terra Nova Extension, and Hebron) is reported in the category NewOil.

Our model indicates that the oil from offshore production will continue to grow, peaking in 2020 at 476 thousand barrels per day (Mbpd). This will represent 12% of the total Canadian oil production. This value does not represent an important change (the proportion was 13% in 2008), but it is important because it will account for 53% of the total conventional oil production. The total Canadian conventional oil production in 2020 will be 900 Mbpd, according to our model. Furthermore, the production at a water depth of 400–1000 ft appears to be the most promising: the forecast for 2030 indicates a production of 315 Mbpd. As a comparison, the conventional oil production in 2008 was close to 1.4 MMbpd. The sustained growth of offshore oil production, from 350 Mbpd in 2008 to 476 Mbpd in 2020, while all other sources of light oil are decreasing, indicates the importance of Canadian offshore oil production.

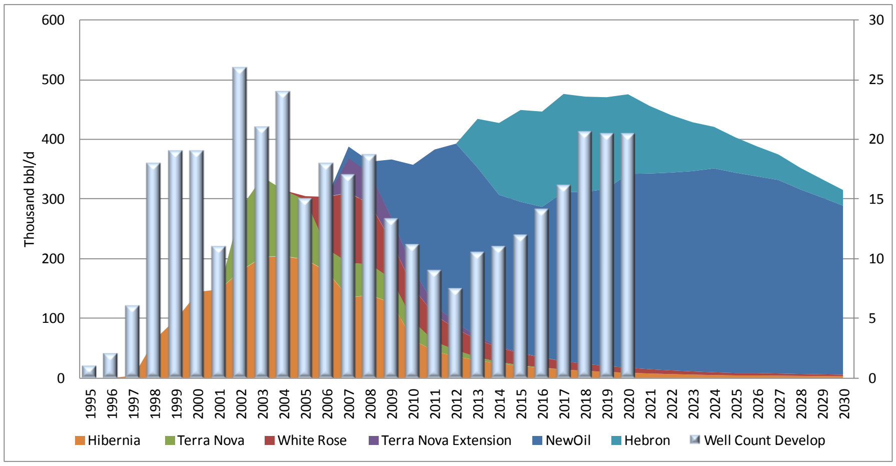

Figure 6: Offshore Eastern Canada oil production (area graph) and well count (bar chart).

The National Energy Board report indicates that in the "Reference Case" the production peaks in 2016 at 438 Mbpd, declining to 65 Mbpd by 2030 (NEB, 2007). In our forecast, the peak production occurs later, mainly because the recovery of oil prices after the 2009 economic crisis was slower than anticipated (seen by comparing the NEB expected oil prices [and the actual prices, (EIA, 2011)). This slow recovery is apparent from the drop in the well count shown in Fig. 6. Another important difference is that we take into account the contribution from the Jeanne d'Arc Basin (located in Newfoundland, Canada) and 500 million barrels of reserves in other unexplored regions that could start producing in 2015. Figure 7 provides a graphical comparison of our forecast and two NEB forecasts.

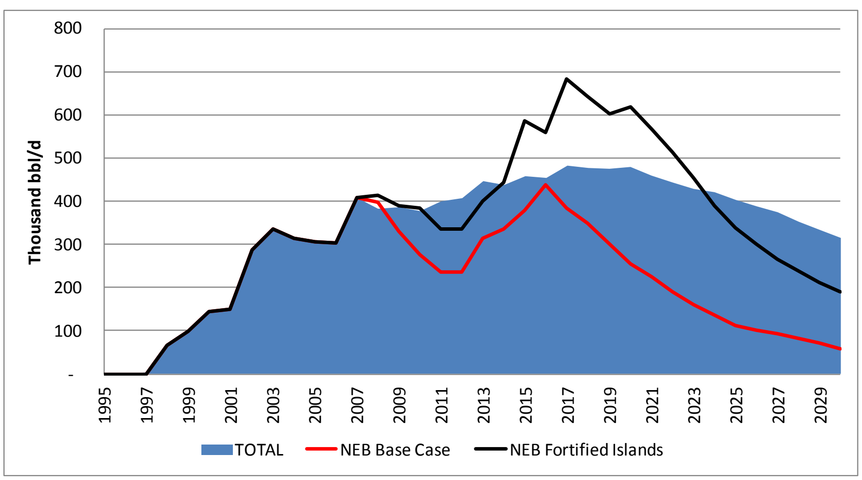

Figure 7: Comparison of our forecast and NEB's forecasts.

Figure 7 reveals that our forecast is closer to the NEB Fortified Islands scenario. In particular, the area below our curve is quite similar to that of this NEB scenario, although our production profile shows slower development after 2014 and higher development after 2024. Note that the NEB Fortified Islands scenario is characterized by a focus on security issues. Specifically, it assumes geopolitical conflicts, no international cooperation, and protectionist government policies (NEB, 2007).

3.2 Oil sands production

There are two types of oil sands production: mined and in-situ (upgraded and non-upgraded). In the latter category, the production is similar to that of onshore and offshore because wells are used to produce oil. In the former category, the oil production uses mining techniques rather than well construction. The National Energy Board (NEB, 2007) provides information about the different mining and in-situ projects. This allows us to forecast the oil sands production by taking into account the different projects currently under development in combination with the detailed scheduling information. However, the possibility of additional oil from new discoveries is not included, mainly because of a lack of detailed information. Because of this lack of information we must simulate the wells in order to apply our well-count approach to oil sands production. The result is then split between the different oil sand projects (mining, in-situ, and in-situ non-upgraded). An artificial well-production unit (pseudo-wells) is associated with the producing assets (trucks, mechanical shovels) of mining projects. Figure 8 displays the resulting forecast for the oil sands.

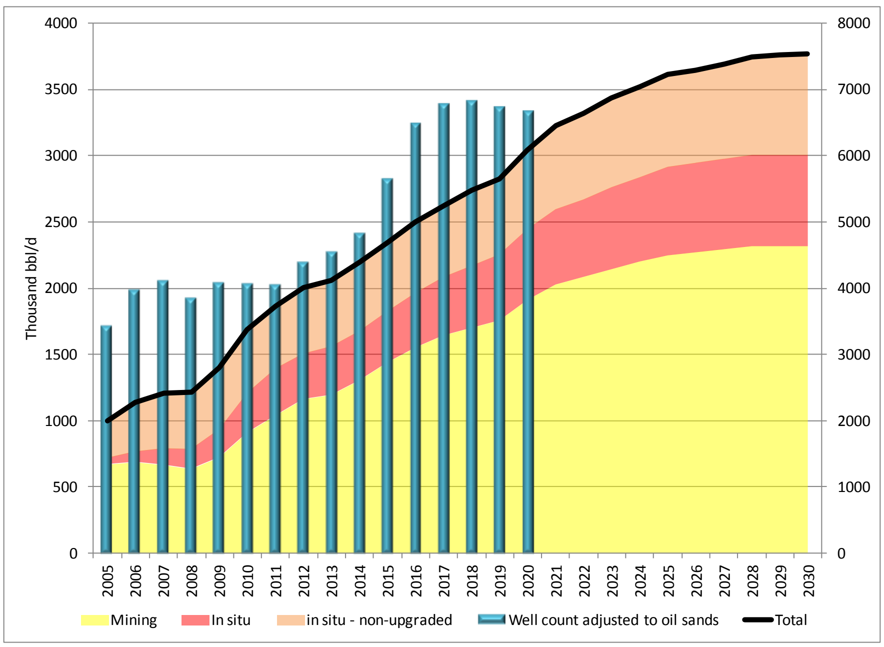

Figure 8: Forecast for oil sands production.

Comparing our results to those reported by (Söderbergh, Robelius, and Aleklett, 2005), we see that a production level of 3.5 MMbpd is achieved later (around 2025 compared to 2015). This difference reflects a slower development of the oil sands in our forecast. The slower development can be explained by the technological challenges associated with oil sands projects and other constraints such as pipeline capacity. Our forecast also reveals that peak oil levels are reached in 2030 at close to 3.8 MMbpd, distributed as follows: 761 Mbpd from the non-upgraded bitumen category and 3 MMbpd from upgraded bitumen. Figure 9 compares our results to those of (NEB, 2007), where the projection for oil sands comes from the extrapolation of their "Reference Case" trends and includes the production from the Saskatchewan oil sands, assumed to start in 2017.

In the NEB forecast, the oil sands production reaches 4.15 MMbpd by 2030, with 2.67 MMbpd from upgraded bitumen and 1.48 MMbpd from non-upgraded bitumen. According to our forecast, the oil sands reserves were close to 64 billion barrels in 2005. Our forecast follows rather closely that of NEB.

Combining all our forecasts for Canada, we find that peak oil happens around 2030 and the most important source is the Western oil sands, as shown in Fig. 10. Specifically, in 2029 the total Canadian oil production will be close to 4.6 MMbpd, and of this 3.8 MMbpd will come from oil sands. This represents an important change in the Canadian oil sector. First, the total oil production in 2030 will be close to double that of 2008

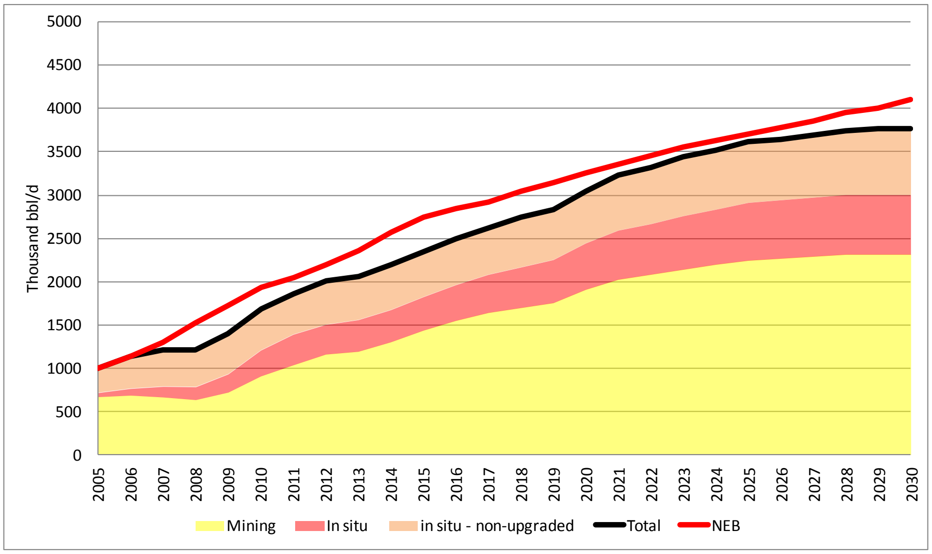

Figure 9: Comparison of our forecast and NEB's forecast.

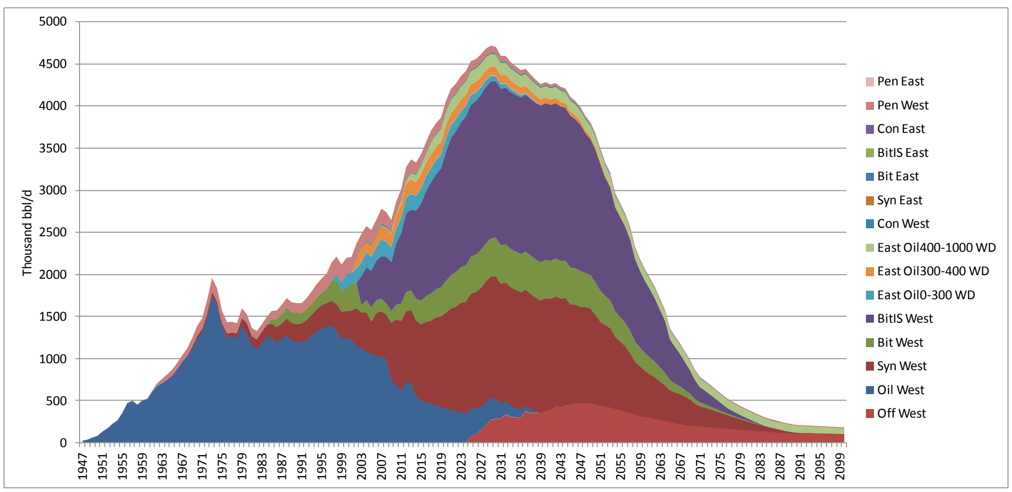

Figure 10: Total Canadian oil production for the BAU scenario.

(slightly above 2.5 MMbpd). Second and more important, in 2030 the oil sands production will account for 81% of the total Canadian production. In 2008, only 1.2 MMbpd (47% of the total) came from oil sands. This change represents an increase of 34% in the oil sands share between 2008 and 2030. As mentioned earlier, the estimated total Canadian production from our model is comparable to the estimates of CAPP and NEB.

In the next section, we use our approach to estimate the available reserves.

3.3 Reserves

Although our model was not originally developed to estimate the reserves, it can be used for this purpose. Assuming that we can accurately estimate the time at which the total available oil is consumed, we simply compute the area below the oil production curve (from the year under consideration to the year when the total available oil is consumed).

Our method for estimating the reserves, which is quite simple given the forecasting model we have developed, makes an important contribution by connecting the oil production, reserves, and economics variables; the literature has acknowledged this as a challenge. It is however important to connect reserves and prices. The economic conditions influence the feasibility of oil production projects, and this in turn affects the oil production levels. According to Jakobsson et al. (2009), constructing a model to explain the evolution of oil production using economic variables can be difficult. To overcome this problem, some authors use a simple extrapolation of past data (Lynch, 2002; Simon, 1996). However, this makes it impossible to grasp the dynamics involved such as the production-cost decline over time due to technological improvements and the cost increases due to peaks in demand and uncertainties about reserves. For instance, approaches that deal well with oil production forecasting do not account for the economic dimension (such as oil prices). On the other hand, models dealing with the economic dimension neglect the physical dimension (Brandt, 2010). In our model we address these issues by connecting the oil production to the well count and thus to oil prices.

To estimate the offshore reserves for 2007, we have extended the time horizon and assume that all reserves will be consumed by 2100. When computing the area below the resulting production curve, we estimate the offshore reserves to be close to 7 billion barrels. To estimate the oil sands reserves for 2005, we again assume that all reserves will be consumed by 2100, and we estimate the reserves to be close to 64 billion barrels. These volumes differ from those in the literature. For instance, (NEB, 2007) estimates the oil sands reserves to be 173 billion barrels. However, these reserves are not attached to a particular year, as in our case.

For 2009, we estimate the reserves to be 80 billion barrels. In 2007, BP (BP, 2007) estimated 11 billion barrels but took only active developments into account. The Oil & Gas Journal (2006) estimated around 175 billion barrels as proven reserves at the end of 2006. The NEB (2006) estimated that the Canadian oil sands contained an ultimately recoverable bitumen resource of 315 billion barrels, and from this the remaining reserves (established for 2004) were 174 billion barrels (Kjärstad and Johnsson, 2009). In 2008, BP (BP, 2008) estimated that "*Canadian proved reserves include an official estimate of 21.0 billion barrels for oil sands 'under active development'*" (EIA, 2009), and it recorded an additional 152.2 billion barrels of reserves, defined as "*'remaining established reserves' minus the reserves 'under active development'*" (EIA, 2009). Also in 2008, the Oil & Gas Journal (2008) estimated reserves of 5.392 billion barrels for conventional crude oil and condensate and 172.7 billion barrels for oil sands. Finally, in 2008 World Oil (2008)] estimated 2007 reserves of 4.9 billion barrels for conventional crude and 174 billion barrels for oil sands. Note that World Oil, (2008) considers these reserves not to be proven and states that their development would require at least 350 trillion cubic feet of gas and the implementation of new technologies.

These contrasting projections illustrate the difficulties of estimating the Canadian oil sands reserves.

4 Conclusion

We have proposed the use of a forecasting model to define oil production profiles. The novelty of our approach is that we consider both economic variables (prices) and physical variables (production and infrastructure) by establishing a link between well count, oil price, and oil production. This approach is combined with a Hubbert logistic function that takes into account the impact of the age of the producing wells. Our model can also be used to estimate the reserves, by using economics variables and trends to assess the role of those reserves and their future implications for oil production.

We have applied our model to forecast a production profile for the Canadian oil sector to 2050, distinguishing between conventional and unconventional sources. According to our model, Canadian production will reach a peak around 2030 and Western oil sands will be the most important source. We want to stress the importance of this change for the Canadian oil sector: oil sands developments have higher energy consumption, emissions, and technological costs. In addition, the poor social acceptability of oil sands may create (national and) international market barriers.

The model forecasts peak production of offshore developments in 2020, indicating that this could be another significant trend in Canadian oil production. The challenges associated with offshore production are the technological cost and the risk of ecological disasters such as the spill of 26,000 l of drilling mud into the Atlantic Ocean in March 2011 (Financial Post, 2012). However, in contrast to that of Western Canada, Eastern Canada oil production benefits from access to international markets. Moreover, the prices of Hibernia Blend usually have parity with the Brent benchmark. This is definitively an incentive for new projects, such as the new joint venture between Chevron, Statoil, and Repsol for the exploration of the Canadian offshore fields (Platts, McGraw Hill Financial, 2012).

As well as providing useful insights into the possible evolution of the Canadian oil sector, this model can be integrated into a bottom-up energy model describing the whole energy system, such as TIMES, to provide the oil supply curves that are typically exogenous to such models (Vaillancourt et al., 2013).

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