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Early New Field Production Estimation Could Assist in Quantifying Supply Trends

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A severe slump in the global E&P industry during 1998/99 saw oil prices bottoming at $10 a barrel - the lowest in 27 years -, U.S. drilling levels hitting their lowest point in 66 years, and global spending on E&P dropping 30 percent to $110 billion[1]. As oil prices picked up from $18 a barrel in June 1999 to $27 in January 2000, U.S. drilling grew 46 percent, E&P capital spending built up steadily reaching an all-time high of $200 billion in 2005. Kazakhstan discovered oil offshore for the first time – the Kashagan field with reserves estimated in 11.6 billion barrels (Gb). This is the largest field discovered anywhere in a single year since 1991. Iran made a big oil discovery, the Azadegan field with reported reserves of 5 Gb. Offshore West Africa, especially Angola and Nigeria, turns out to be one of the world's new great hydrocarbon areas.

Over the last seven years some 140 new oil fields, ranging in size from 11.6 Gb to 50 million barrels (mb) of recoverable reserves, have been discovered worldwide. They contain a total of 85 Gb of recoverable reserves, with a production potential of roughly 15 mb/d. One hundred and twenty-seven of these new fields are located offshore, and fifty-three of these are deepwater fields. Only thirteen of the fields have been discovered onshore, many of which are in remote areas. In general, both offshore and onshore regions are characterized by complex environmental constraints and limited opportunities for acquiring reservoir and well production potential data. A deepwater well may cost upwards of $100 million!

After drilling a successful exploratory well, depending on the probable size of the find, one or two additional exploratory and one or two appraisal wells are drilled for extended well testing. Sophisticated visualization/interpretation software allows borehole calibration of seismic volumes for prediction of lithology, porosity and fluid connectivity between wells. This data is essential to obtain a comprehensive production evaluation before a development plan for the field can be made. The evaluation period can take 2 to 5 years or more from the time of discovery. Currently, 105 of the 140 new fields are still under development or in the planning stage. Only 35 fields, with a production potential of 3 mb/d, are on stream. Consequently, it is of paramount interest to have available an *early* estimate of the production potential a new field discovery can put forward. This threshold is vital to supply analysts and for the design of production facilities.

The objective of this paper is to develop an algorithm that would provide an *early* estimate of the production potential of newly discovered oil fields. Based on the logistic equation which has

[1] "Global E&P capital expenditure: trends & determinants", Ivan Sandrea and Ghassan Aloshban, Oil and Gas Financial Journal, Feb. 10, 2006.

proven to successfully replicate the production behavior of both oil[2] and gas[3] fields, the *early* model is developed using field performance data from eight mature major oil fields around the world. These fields typify a broad spectrum of production characteristics: onshore, deepwater, heavy and light oils, and size variations from 15 Gb to 700 mb. The model is then used to predict the production potential of 18 new, world-class oil fields that have recently been put on stream or are scheduled to go on stream in the near term[4]. The predicted production potential values are compared with those available from profiles of the fields made public by stakeholders' disclosures. A world-class oil field is defined as one containing 50 million barrels or more of recoverable reserves and having a production potential of 45,000 b/d and up.

The *Early* Production Potential Model

The logistic equation is defined as follows:

$$dQ/dt = r_o\, Q\,(1 - Q/K) \qquad (1)$$

where Q is the cumulative oil production, dQ/dt the annual production rate, r_o the initial production growth rate, and K the ultimate recoverable reserves (URR).

The production potential or peak production of an oil field occurs at the half-life (Q= ½K) of its recoverable reserves. Solving Equation 1 for these conditions gives:

$$dQ/dt|_{peak} \equiv q_{max} = r_o\, K / 4 \qquad (2)$$

Normally the parameters r_o and K are established from extrapolation of the steady state decline plot of (dQ/dt)/Q versus Q. For newly discovered oil fields, however, these parameters have to be established from other sources since there is no existing production history. At the time of discovery, the recoverable reserves, K, would be the volumetric estimate of the geologic prospect discovered by the successful exploratory well. However, in order to estimate the initial production growth rate $r_{o,}$ it is necessary to establish a correlation between the parameters r_o and K. This was accomplished using decline analysis to calculate the values of these two parameters for the eight sample fields (see Table 1). The correlation obtained is shown in Fig. 1. The least squares best-fit power regression is:

$$r_o = 41.885\, K^{-0.3866} \qquad (3)$$

This has a correlation coefficient of 0.972. Combining Equations 2 and 3 gives the *early* production potential model for new fields, namely:

$$q_{max} = 287\, K^{0.6134} \qquad (4)$$

[2] "What About Deffeyes' Prediction that Oil Will Peak in 2005?", Rafael Sandrea, MEES, Vol. 48 - No. 37, Sept. 12, 2005.

[3] "Global Natural Gas Reserves – A Heuristic Viewpoint", Rafael Sandrea, MEES, Vol. 49 - No. 11, March 13,2006 (*Part 1*); Vol. 51 - No. 12, March 20, 2006 (*Part 2*).

[4] "Prices set firm, despite massive new capacity", Chris Skrebowski, Petroleum Review, October, 2005

q_{max} is expressed in thousands of barrels per day (kb/d) and K is the volumetric estimate of the recoverable reserves in billions of barrels. A graphic solution of Equation 4 is shown in Fig. 2.

Another handy algorithm that defines the steady state decline trend line is:

$$D = r_o\,(1 - Q/K) \qquad (5)$$

This provides a straightforward determination of D, the annual production decline rate of the field, as a function of its degree of reserves depletion, Q/K. Fig. 3 depicts a universal plot of Equation (5).

Early model reliability

Table 1 summarizes the initial production growth rates and recoverable reserves values obtained using the decline curve technique (Equation 1) for the eight mature giant oil fields. These values are termed field values since they were established with field production data. The calculated production potential values obtained with the *early* model, Equation 4, are then compared with the corresponding actual field peak production values. The average deviation is 6.6%, with estimated values for individual fields varying between 2% and 18% from the field values. Only two fields had deviations above 8%.

The *early* model was then applied to a mix of eighteen new, world-class conventional oil fields (see Table 2) that have recently been put on stream or will do so over the next six years. They vary in size from 230 mb to 11.6 Gb of recoverable reserves; their total reserves are 35 Gb which can sustain a production potential of 5.6 mb/d. Two of the fields (Agbami and Kashagan), with a combined production potential of 1.4 mb/d, are yet to go on stream. Five of the fields currently on production will continue under development through 2010 in order to arrive at their full potential of 1.9 mb/d. The 18 fields were selected to demonstrate the validity of the *early* algorithm in support of a wide variety of geological conditions over 12 countries. For example, the Peng Lai (China), Elephant (Libya) and Erha (Nigeria) fields each has 500 million barrels of recoverable reserves which generate a field production potential of 150 - 160 kb/d, a fine window of similarity.

The peak production potentials predicted by the *early* model must be compared with actual field behavior or with theoretical values obtained from dynamic reservoir studies. Since the fields are new, there are no true field production potential values per se available. Values from stakeholders' public disclosures of field profiles and from other public sources were used as a basis of comparison. It should be pointed out, however, that these published values are more correctly nameplate capacities of the production facilities which are normally set at 10 - 15% *below* the field peak production potential. The object is to maintain a plateau-like production level over a prolonged period in order to optimize the investment.

With these considerations in mind, the peak potentials for the eighteen selected oil fields were calculated using the *early* model. The results and comparisons with the known nameplate capacities are summarized in Table 2. All of the *early* production potential estimates are *higher* than the corresponding nameplate capacities. This is as would be expected since the production facilities are designed at a lower capacity (10-15%) than the corresponding peak field production level. The average variation between the *early* estimates and the nameplate values for the 18 fields was 17.5%.

Peak potential as determined by the *early* algorithm, Equation 4, depends critically on the accuracy of the estimated value of the field's reserves (K). The published reserves values for several (7) of the fields are specific only to single digit accuracy, such as 0.5 Gb or 6 Gb. This level of precision can generate an intrinsic 5% deviation in the peak production values estimated with the *early* model. When the *early* estimates were compared with the nameplate capacities for the 11 fields with double digit precision reserves values, the average deviation was reduced to 11.5%. This is well within the 10-15% design spread between nameplate capacities and field peak production values.

Final Comments

- The *early* model was developed to provide an estimate of the peak production potential of newly discovered oil fields. It is intended to be applied as soon as a wildcat is confirmed to be an oil discovery. Establishing the real potential of an oil field may take 2 - 5 years after discovery, following a costly appraisal drilling program.

- The predictive algorithm, Equation 4, is simple and only requires a geologic approximation of the recoverable reserves of the target field at the time of discovery. It provides an estimate of field production potential, on average 11% *higher* than the so-called nameplate production capacity. The latter is a plateau rate normally set at about 10 - 15% *below* the true field peak potential. Consequently, the *early* model provides a sound estimate of a field's peak production.

- The *early* model is an effective tool for supply analysis; it is bidirectional in that it can predict production potential or reserves, when only one of these two parameters is announced at the time of discovery, as sometimes occurs. In other cases, as when the field is developed in phases, the reserves being committed in each phase can be easily accounted for.

In the final analysis of supply trends, production capacity from newly discovered fields is only one component of the equation. New capacity is constantly being mitigated by natural depletion of the existing reserves. Overall global depletion is presently just about 2.5% per year[*] which represents an annual loss of 1.8 mb/d of conventional crude oil production. Worldwide production capacity going on stream from new oil field discoveries has averaged roughly 500 kb/d per year over the last 7 years. Some 12 mb/d of new production capacity from 105 of the 140 oil fields discovered in the last 7 years is still awaiting development to go on stream. There is a need for a fast track development plan. At current rates of project slippage, depletion will continue eating into discovery gains.

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[*] Obtained from Equation 5 for r_o = 4.8%/year, K = 2000 Gb and Q_{2004} = 957 Gb. Analogous data for The Big Three: U.S. (D = 1.0%/yr. for r_o = 5.8%/yr., K = 225 Gb, Q_{2004} = 185 Gb); Russia (D = 2.1%/yr for r_o = 9.4%/yr., K = 195 Gb, Q_{2004}= 151 Gb); Saudi Arabia (D = 2.7%/yr. for r_o = 7.0%/yr., K = 165 Gb, Q_{2004} = 101 Gb).

Table 1. Comparative Estimates of Production Potential of Eight Giant Oil Fields varying in size from 700 mb to 15 Gb

Field (Country)	Recoverable Reserves, K Gb	Production Began year	Initial Production Growth Rate, r_o %/year		Peak Production, q_{max}, kb/d,		
	Field Value		Field Value	*Early* Estimate	Field Value	*Early* Estimate	% Difference
Cusiana (Colombia)	0.7	1992	48.0	48.0	250	230	- 8.0
Furrial (Venezuela)	2.0	1986	24.0	32.0	450	440	- 2.2
Forties (UK)	2.5	1975	27.0	29.4	530	500	-5.6
Marlim (Brazil)	2.7	1991	32.0	28.5	600	530	-11.6
Statfjord (Norway)	3.5	1980	26.0	25.8	640	620	-3.2
Cantarell* (Mexico)	10.5	1980	14.0	16.9	1,150	1,215	5.6
Prudhoe Bay (USA)	11.4	1977	17.5	16.3	1,550	1,275	-17.7
Romashkino **(**Russia)	15.0	1950	16.0	14.7	1,600	1,510	-5.6

Notes: Field values of peak production were obtained from the actual production history; field values of initial production growth (r_o) and ultimate recoverable reserves (K) were determined from the decline trend line of the production history. Production refers to conventional crude oil. *Early* estimates of initial growth rate and peak production were made using Equation 3 & 4, respectively. *Cantarell's recoverable reserves correspond to the value prior to the initiation of nitrogen injection in 2000; an additional 2.3 Gb of oil recovery have been attributed to the injection program.

Table 2. *Early* Estimates of Peak Production Potential for Eighteen Newly Developed Oil Fields

Field (Country)	Operator	Discovery Year	First Production Year	Recoverable Reserves, Gb	Production Potential, kb/d		
				Published Value	Published Value	*Early* Estimate	% Difference
White Rose (Canada)	Husky	1984	2005	0.23	100	115	15.0
Mad Dog (USA)	BP	1998	2005	0.25	100	120	20.0
Schiehallion-Loyal (UK)	BP	1993	1998	0.42	160	170	6.2
Peng Lai (China)	ConocoPhillips	1999	2002	0.5	160 (2008)	185	15.6
Elephant (Libya)	Eni	1997	2004	0.5	150	185	23.3
Erha (Nigeria)	ExxonMobil	2000	2006	0.5	150	185	23.3
Buzzard (UK)	Nexen	2001	2006	0.55	190 (2008)	200	5.2
Bonga (Nigeria)	Shell	1996	2005	0.6	200	210	5.0
Girassol (Angola)	Total	1996	2001	0.73	215	235	17.5
Agbami (Nigeria)	ChevronTexaco	1998	2008	0.8	210	250	19.0
Kizomba B (Angola)	ExxonMobil	1999	2005	0.91	250	270	8.0
Dalia (Angola)	Total	1997	2006	1.0	240	285	18.7
Hassi Berkine So. (Algeria)	Anadarko	1995	2001	1.3	285	335	17.5
Roncador (Brazil)	Petrobras	1997	1999	2.3	450 (2010)	475	5.5
Sakhalin (Russia)	ExxonMobil	1979	2006	2.3	370 (2007)	475	28.3
Qatif **(Saudi Arabia)**	Aramco	1945	2004	5	500	770	54.0
Tengiz (Kazakhstan)	ChevronTexaco	1979	2001	6	700 (2010)	860	22.8
Kashagan (Kazakhstan)	Eni	2000	2008	11.6	1,200 (2012)	1290	7.5

Notes: Published values of production potential generally correspond to nameplate production capacities. Whenever possible, the values were adjusted to reflect clean oil production. The field may be developed in phases but the production potential listed is the total potential for all phases. When a (year) is specified below the production potential value this indicates that expansion programs are scheduled through that period to attain the indicated production potential. *Early* estimates are calculated with Equation 4.
Sources: Stakeholders' public disclosures; World Oil; Oil & Gas J.; Petroleum Review.(http://www.globalpublicmedia.com/articles/539).

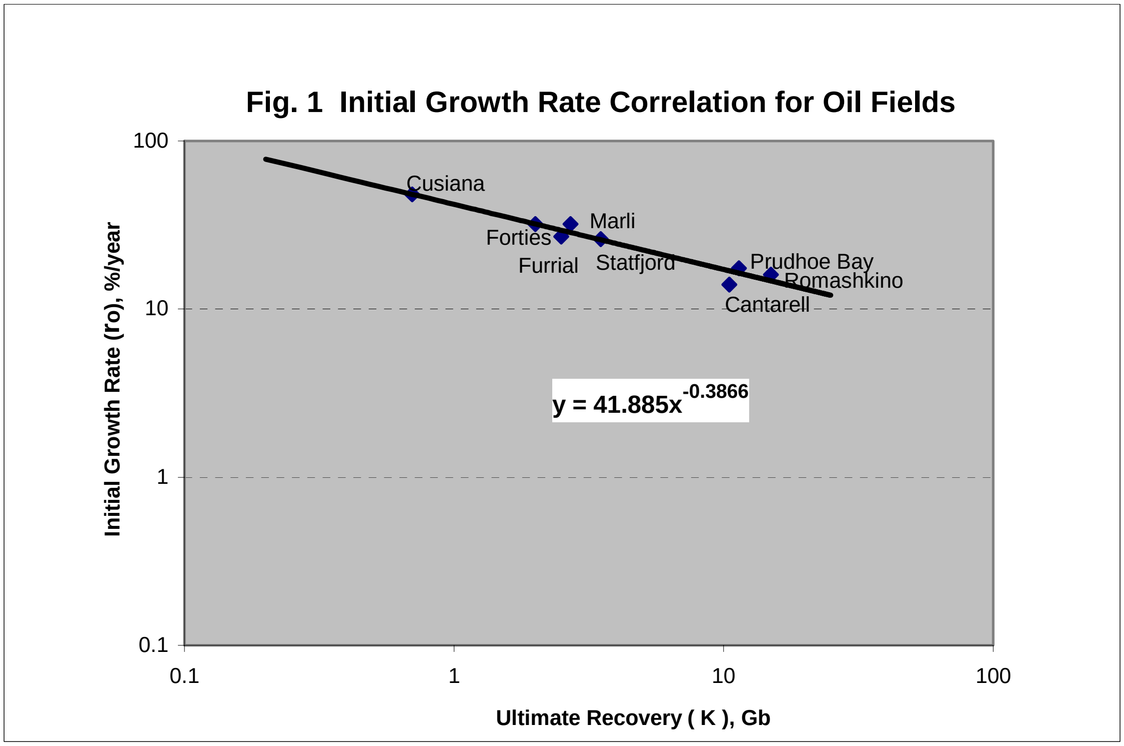
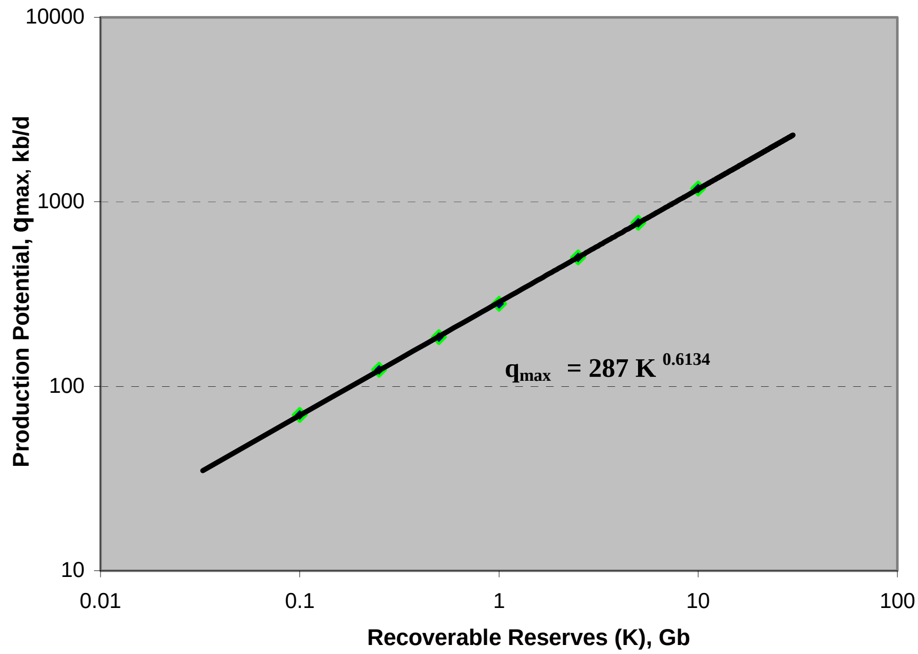


Fig. 1 Initial Growth Rate Correlation for Oil Fields
100
10
1
0.1
Cusiana
Marli
Forties
Furrial
Statfjord
Prudhoe Bay
Romashkino
Cantarell
y = 41.885x^-0.3866
0.1
1
10
100
Ultimate Recovery (K), Gb
Initial Growth Rate (ro), %/year

Fig. 2 Production Potential vs Recoverable Reserves for Oil Fields



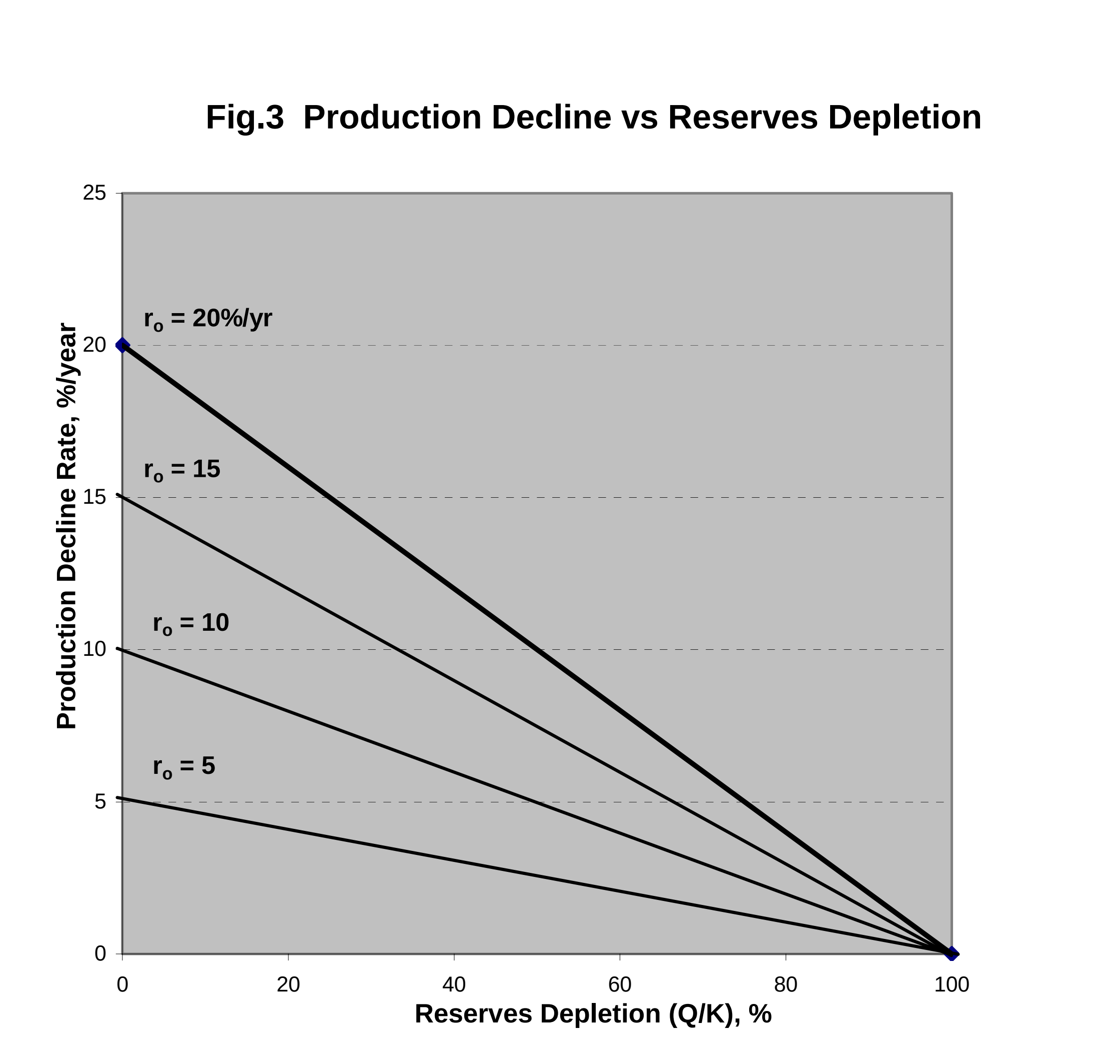


Fig.3 Production Decline vs Reserves Depletion
Production Decline Rate, %/year
Reserves Depletion (Q/K), %
r_o = 20%/yr
r_o = 15
r_o = 10
r_o = 5
0
5
10
15
20
25
0
20
40
60
80
100