ENERGY REQUIREMENT FOR NORTH SEA OIL BY SECONDARY AND TERTIARY PRODUCTION METHODS

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PREFACE

Secondary recovery (water injection) and tertiary recovery (miscibles, chemicals, etc.) are more resource-demanding than primary recovery. Moreover, the necessary natural resources: energy, water, materials (chemicals), as usual, interact with each other. Such a process is well suited for analysis in terms of WELMM (water, energy, land, materials, manpower).

However, there is still much uncertainty about the data because tertiary recovery is mainly in the development stage. On the way to a more complete WELMM analysis, it has then been only natural to explore as a first step the energy balance of secondary and tertiary recovery for the oil fields of the North Sea.

This study is a logical continuation of the more complete study on WELMM resources reqirements for the North Sea and, in an interesting way, opens the door to a prospective study of future ultimate oil recovery in the North Sea and its WELMM impact.

Michel Grenon

ABSTRACT

This paper presents a review of the resources necessary to develop 13 UK offshore oil fields for purposes of obtaining primary recovered oil. An estimate is provided of the increasing energy requirement for a metric ton of North Sea oil due to secondary production methods. Also presented is an estimate of the possible energy requirements should tertiary (i.e. enhanced oil recovery) techniques be undertaken in the North Sea.

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INTRODUCTION

There is considerable interest today in the energy required for the extraction of resources [1]. It has been argued [2,3] that the energy required for extraction is a measure as good as any of the difficulty of assessing a resource. Therefore the estimate of energy requirements for extraction as a function of future production could serve as an indicator of future cost.

This paper presents an estimate of the increasing energy requirements for a metric ton[1] of North Sea oil (averaged over 13 specific fields) due to secondary production methods. An estimate is also made of the possible energy requirement should tertiary methods be embarked upon, though it must be stressed that it is not yet known whether tertiary methods will ever be used in the North Sea, and this estimate is subject to large uncertainties.

PRIMARY OIL RECOVERY

Primary oil recovery is the reliance upon natural energy forms in the reservoir for the production of crude oil. Such natural energy forms include natural water drive, expansion of free gas, oil, water, and solution gas; and capillary and gravitational forces.

To bring about the initial primary recovery of oil from the North Sea a large portion of resources has been and is being

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[1] or tonne, in the following simply referred to as ton.

expended in exploration, platform and pipeline construction, production well drilling, and the production process itself.

The development of thirteen commercially deemed oil fields in the UK sector of the North Sea requires directly or indirectly the following activities for primary recovery:

Total number of miles surveyed	310,700 miles (500,000 km)
Exploration wells drilled	474
Appraisal wells drilled	169
Production wells drilled (637 anticipated to be drilled to complete the 13 fields)	293
Total number of miles of major crude pipelines constructed or under construction	487 miles (784 km)
Total number of miles of field pipelines (crude) constructed or under construction	65.3 miles (105 km)
Production platforms installed	11 (steel) 3 (concrete)
Production platforms under construction or being constructed or being installed	2 (steel) 4 (concrete)

The total amount of material and energy resources necessary for the construction of all facilities in the oil field in UK waters is 12.2 million metric tons. Energy materials represent the major quantity, 7.6 million tons, and structural and consumable materials represent 4.6 million tons of the total.

SECONDARY PRODUCTION METHODS

Because of the large amount of resources utilized for primary recovery it seems important to continue the evaluation of how larger quantities of oil can be obtained for the resources expended.

There is now a terminology problem regarding which technologies for enhanced oil recovery should be classified as "secondary" and "tertiary". This arises because the more sophisticated methods previously regarded as tertiary may come to be used in the earlier stages of field development in order to obtain the best overall return. Also some secondary techniques such as injection of water or gas could be termed "enhanced primary" methods if the primary production was due to natural water or gas drive. For the present paper we will regard the injection of sea water as being the main secondary method in use in the North Sea. As shown in Table 1 water injection is being used (or planned to be used) in almost all North Sea fields currently under development. As far as can be ascertained the re-injection of natural gas is being used primarily as a means of storing the gas for later use and not as an aid to oil production. Consequently energy requirements for gas re-injection should not be counted as an input to oil production.

Table 1. The 13 fields covered by the analysis

Field Name	Water Injection Planned	Estimated Recoverable Reserves (MTOE[2])
Argyll	no	4
Auk	yes	10
Beryl	yes	54
Brent	yes	270
Claymore	yes	68
Cormorant	yes	22
Dunlin	yes	79
Forties	yes	243
Heather	yes	20
Montrose	yes	20
Ninian	yes	149
Piper	yes	108
Thistle	yes	74

[2]million tons of oil equivalent

TERTIARY PRODUCTION METHODS

The term tertiary production encompasses thermal methods (e.g. steam-injection), carbon dioxide flooding, and chemical flooding (surfactants to reduce surface tension and ease the passage of oil through the rock and polymers to improve the efficiency of water injection). All these methods are still in the experimental stage for land-based fields, and it is not known whether they will be used in the North Sea. However it is possible to make some general observations regarding tertiary recovery in the North Sea, and then to make a tentative estimate of the possible energy requirements. Thermal methods are unlikely to be used in the North Sea for two reasons. Firstly, they are best suited to higher viscosity crudes, and the crude found in the North Sea is of low viscosity. Secondly, thermal methods are considered unsuitable for field depths greater than ~ 3000 ft because of the associated cooling problems. Thus it seems that carbon dioxide or chemical flooding are the only candidates for tertiary recovery in the North Sea. Of those we consider chemical flooding to be the more likely choice as this is known to be suitable for use after a water injection program and, as stated above, water injection is being used in most North Sea fields.

THE ANALYSIS

The analysis was carried out using data collected by J.K. Klitz as part of the IIASA WELMM[3] analysis program [4]. This data base contains detailed information on all the facilities being used in, and associated with, the 13 fields currently in the most advanced stages of development. A complete WELMM analysis has been carried out for these fields up to and including primary production, and this yielded a figure for the

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[3] Water, Energy, Land, Manpower, and Materials.

average gross energy requirement[4] for crude oil (primary recovery) of 0.497 GJ/ton, which compares well with other studies of single North Sea fields [5,6].

Secondary Production

In order to calculate the increasing energy requirement as production is phased in, it is necessary to know what quantity of oil can ultimately be attributed to secondary production (above that which would have been obtained by primary production alone), and then allocate the additional energy inputs accordingly.

Let

T = total oil in place, in MTOE;

R = recoverable reserves, in MTOE;

r_p = fraction of T recoverable by primary recovery alone;

r_s = fraction of T recoverable using primary and secondary methods;

Δr_s = additional fraction of T due to secondary recovery = $r_s - r_p$.

The value for the recoverable reserves, R, is normally quoted assuming secondary recovery so:

$$R = r_s \cdot T \quad . \tag{1}$$

Now let

E_i = initial energy invested in field (construction platforms, pipelines, etc.), in GJ;

e_p = ongoing energy requirement for primary production, in GJ/ton;

e_t = energy for transportation of crude to shore, in GJ/ton.

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[4]Includes all direct, indirect, and capital energy costs of landing one metric ton of crude oil onshore and transferring it to a refining facility.

Since the initial investment E_i is made in equipment and facilities which are used in both the primary and secondary phases, E_i must be apportioned to oil produced in both phases. Thus the energy requirement for primary production, e_1, in GJ/ton, is given by:

$$e_1 = \frac{E_i}{R} + e_p + e_t \quad . \tag{2}$$

Now let

E_s = additional energy investment in secondary production facilities, in GJ;

e_{ps} = additional ongoing energy for secondary production, in GJ/ton;

A = quantity of oil recovered after secondary production starts, in tons.

e_{ps} can vary with time, so we have $e_{ps} = e_{ps}(t)$.

We need to define r'_s as the fraction of A attributable to water injection, that is:

$$r'_s \cdot A = \Delta r_s \cdot T \quad ,$$

or

$$r'_s = \frac{\Delta r_s \cdot T}{A} \quad .$$

The fraction r'_s of the quantity A is extracted at an energy cost of

$$e_1 + \frac{E_s}{r_s T} + e_{ps}(t) \quad ,$$

while the remaining fraction, $1 - r'_s$, of A have an energy cost of e_1.

Thus the energy requirement during secondary recovery, $e_2(t)$, is given by:

$$e_2(t) = (1 - r'_s)\, e_1 + r'_s \left[\frac{e_1 + E_s}{\Delta r_s T} + e_{ps}(t) \right] \quad , \text{ in GJ/ton,}$$

which simplifies to:

$$e_2(t) = e_1 + r'_s \left[\frac{E_s}{\Delta r_s T} + e_{ps}(t) \right] \qquad (3)$$

For all the fields the operating companies' estimate was taken for the recoverable reserves, R. In some cases estimates were also available for T, the total oil in place. Where this was not available it was calculated from (1) using either the quoted value of r_s or an assumed value of $r_s = 0.41$ (the average of all estimates of r_s available). In very few cases was there a figure for r_p, and in general an assumed value of $r_p = 0.2$ was used.

For each field a production profile was constructed using the operators' estimate of the time of start of production and the time, duration, and magnitude of peak production. An exponential decay of 10 percent per annum was used for the declining phase.

The most important contribution to the additional energy investment in secondary production, E_s, is the provision of extra wells for the injection of water. Using the data collected in J.K. Klitz' IIASA study [4] an energy analysis for a typical well (11,000 ft depth) was made, and this was used in conjunction with available drilling data to find E_s for each field. Accurate figures for the planned numbers of production and water injection wells were available as well as details of numbers of wells to be drilled in a given year.

Further assumptions had to be made in order to estimate $e_{ps}(t)$. For most fields there is some uncertainty regarding the timing of the onset of water injection, the volume of water to be pumped, and the pumping pressure. These parameters depend on characteristics of the field which can only be ascertained once production is under way. For example, the Piper field has been found to have a substantial natural aquifer and may not now need additional water injection, while in the Forties field water injection is already under way. However it is possible to make some general deductions from the information available. For example, in all cases where water injection equipment is installed on a platform the capacity of the equipment, in barrels of water per day, is equal to or slightly greater than the estimated peak production of the field, in barrels of oil per day. In the case of the Auk field it is estimated that water injection of 70,000 b/d may be needed throughout the life of the field, while peak production is estimated at 50,000 b/d. From these facts we conclude that it is reasonable to assume that on average the rate of water injection continues at the maximum rate while oil production declines in the later stages. If flow rate, pressure, and pump efficiency are known the energy requirement for pumping can be calculated. The manufacturer's quoted pump efficiencies range from 28% to 32%; a figure of 30% was used. An injection pressure of 1250 p.s.i. at the surface was used throughout. Sensitivity calculations were made to find the effects on the final result of 50% uncertainties in either pressure or flow rate.

For each of the 13 fields a profile for the energy requirement was constructed using equations (2) and (3) for the primary and secondary production phases. The weighted average energy requirement was then calculated, and this is shown as a function of cumulative production in Figure 1. The vertical error bars show the results of the sensitivity calculations described above. Uncertainties in the timing of events are estimated to be ± 1 year in the early stages, rising to ± 3 years in the later stages; these lead to the horizontal error bars in Figure 1. It is worth noting here that by taking an average over 13 fields at least some of the uncertainties will cancel out.

Tertiary Production

As already stated it is not known whether tertiary production will be embarked upon in the North Sea, or what the results would be. Consequently the analysis for this stage is very simple and is based on what is known for chemical injection

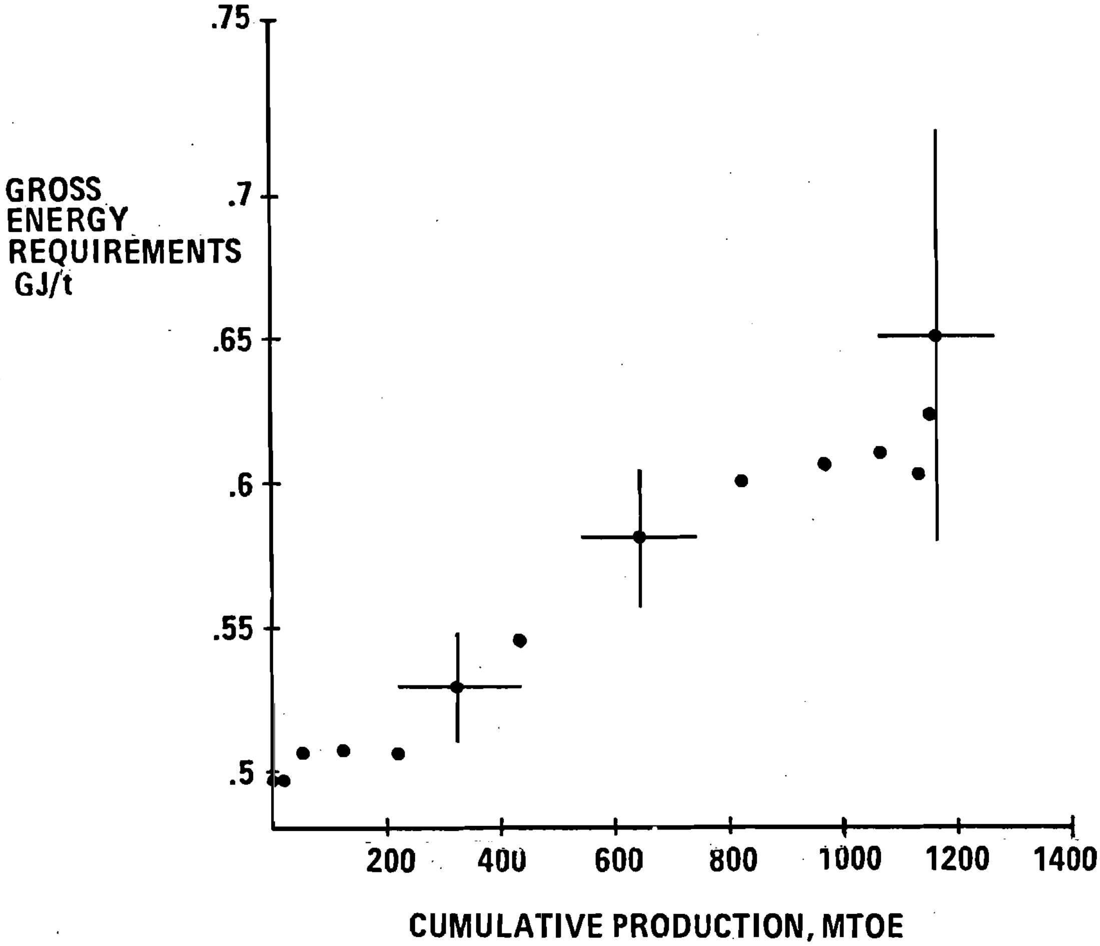

Figure 1. The increasing energy requirement due to secondary production methods for 13 North Sea fields.

programs in other parts of the world. Most information is available for fields in the USA where chemical injection is being used to follow secondary water injection. The different estimates given in the literature [7,8] for the possible increase in recovery factor due to tertiary methods range from 5% to 20%. For the present 13 fields under consideration these figures correspond to an extra production of 56 to 224 MTOE.

The best available estimates for the requirements in chemicals per additional barrel of oil produced [9] are:

10^{+5}_{-3} lb petroleum sulfonates;

3 lb alcohols;

$1 \pm 1/4$ lb polymers.

In energy terms these chemical inputs correspond to an extra 1.78 to 3.19 GJ per additional ton of oil produced. If we assume that the ongoing energy requirements for running the platform, pumping, etc., are the same as in the secondary phase then the above range of uncertainty in the energy requirement for chemicals is two orders of magnitude greater than other conceivable energy inputs, such as the transport of the chemicals by sea from the UK to the platform.

The extremes of the possibilities of tertiary production are shown below:

	Min.	Max.	
Extra Production (for 13 fields):	56	224	MTOE
Gross Energy Requirements:	2.43	3.84	GJ/ton

CONCLUSIONS

The increase in the average energy requirement due to secondary production techniques has been calculated for 13 specified fields in the North Sea. The gross energy requirement increases from 0.497 to 0.651 GJ/ton, that is from 1.12 to 1.5 per cent of the calorific value of the crude oil produced.

The possibilities of tertiary production have been calculated based on data available for chemical injection programs in the US fields. The possible extra production from the 13 fields due to tertiary techniques is between 56 and 224 MTOE at an energy requirement of between 2.43 and 3.84 GJ/ton. While we recognize that in practice it will be costs and not energy requirements that determine whether tertiary methods are embarked upon, even the higher figure for the energy requirement represents less than 10 per cent of the calorific value of the crude produced, indicating that tertiary methods for increasing the productivity of North Sea fields are worthy of more detailed consideration.

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