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Decline and depletion rates of oil production – a comprehensive investigation

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Abstract:

Two of the most fundamental concepts in the current debate about future oil supply are oil field *decline rates* and *depletion rates*. These concepts are related, but not identical. This paper clarifies the definitions of these concepts, summarises the underlying theory and empirically estimates decline and depletion rates for different categories of oil field. A database of 880 post-peak fields is analysed to determine typical depletion levels, depletion rates, and decline rates. This demonstrates that the size of oil fields has a significant influence on decline and depletion rates, with generally high values for small fields and comparatively low values for larger fields. These empirical findings have important implications for oil supply forecasting.

Key words: depletion rate, decline rate, peak oil, field-by-field analysis, depletion level

1. Introduction

Non-renewable fossil fuels provide around 81% of the global primary energy supply and oil remains the single largest primary fuel, satisfying 33% of the world's energy needs in 2009 (IEA, 2011). Given the high reliance on oil, particularly within the transportation sector, it is evident that policymakers and the public need reliable forecasts of future oil supply.

Two of the most fundamental concepts in the current debate about future oil supply are oil field *decline rates* and *depletion rates*. These concepts are related, but not identical. However, analysts and laymen alike tend to get these concepts mixed up, leading to misunderstandings and flawed conclusions. In addition, the definition of depletion rates can vary. The term *decline rate* refers to the annual reduction in the rate of production from an individual field or a group of fields, after a peak in production. Detailed empirical analyses of decline rates have been produced for well over 50 years and most studies tend to agree on the typical decline rates for different categories of field, despite some differences in details (Höök *et al.*, 2009a, b). However, the possible causes of observed decline rates are debated. Some propose that the observed decline rates are mainly caused by underinvestment while others argue that the reason is simply physical limits to production rates.

On the other hand, *depletion rates* refer to the rate at which oil is produced in a field or region expressed as a fraction of either the ultimate recoverable resources (URR) or the remaining reserves. Depletion rates have been studied since the late 1970s (Flower, 1978) and the concept has become prominent in the peak oil debate due largely to the work of Campbell (1992; 1996; 2006; Campbell & Heapes, 2008) - although he is far from alone in using depletion rates. However, the definition of depletion rate and the methodology for estimating them has varied over time and has never been as standardized as is the case for decline rates. Perplexing terminology, inconsistent theory, lack of clear methodology, and different definitions have contributed to a confusion surrounding depletion rates. This paper summarizes these topics and brings more clarity from both theoretical and empirical perspectives.

2. Fundamentals of oil production

Conventional oil accumulates through long geological processes in underground formations known as reservoirs. Typical reservoirs consist of porous rocks, such as sandstone or carbonates, where petroleum resides in the tiny void spaces between the rock grains. An oil field may consist of one or several reservoirs reachable from the surface by drilling.

Current global oil production is predominantly derived from conventional oil fields with minor contributions coming from natural gas liquids (NGL – ethane, propane, butane and pentane), unconventional oil, and other liquids. For historical reasons, oil is commonly measured in barrels corresponding to a volume of 42 US gallons or approximately 159 litres. An oil field may contain anything from less than a million barrels (Mb) to many billion barrels (Gb). Robelius (2007) estimated the number of identified oil fields in the world to be around 47,500. In contrast, IEA (2008) estimate there are around 70,000 fields, but also notes that the exact number depends on how specific fields are delineated and highlights data discrepancies. However, the importance of individual fields to global oil supply varies widely, with around 25 fields accounting for one quarter of global oil production and a few hundred 'giant' fields (> 500 million barrels) accounting for approximately one half of global production (Höök *et al.*, 2009b). All fields share similar overall behaviour, although the magnitude of production can differ significantly.

An oil field typically exhibits the production profile seen in Figure 1. However, significant deviations can be caused by development history, changes in technology or oil

price, accidents, political decisions, sabotage, and similar factors. Some fields have short plateau periods, more resembling a single peak, while others (especially large fields) may keep production relatively constant for many decades. But at some point, all fields will reach the onset of decline and begin to experience decreasing production.

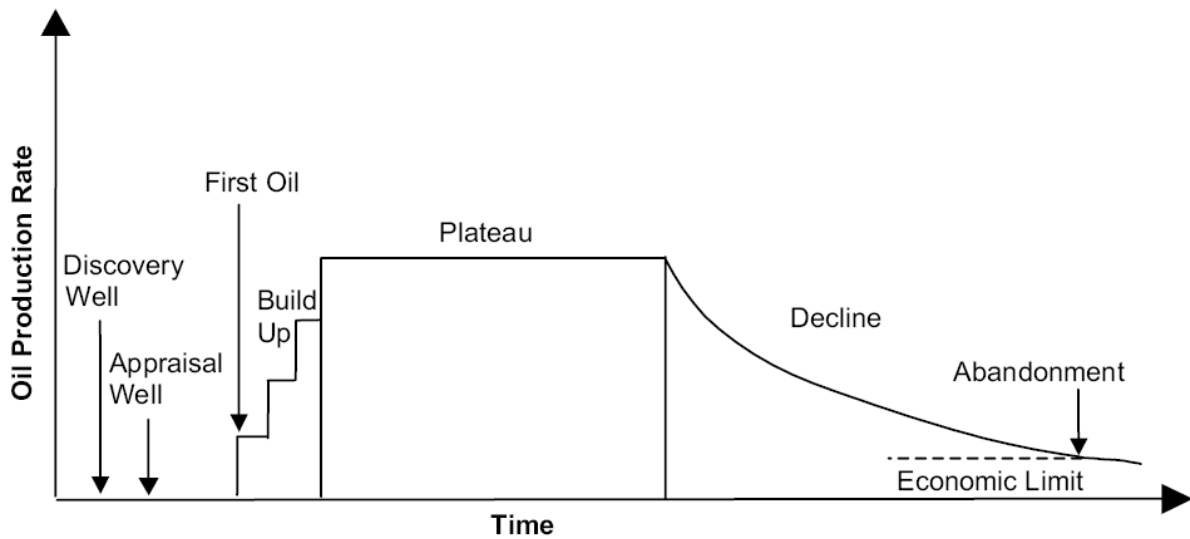


Figure 1. Idealized production behaviour of an oil field. Source: Höök *et al* (2009a).

The extraction of oil from a reservoir is commonly divided into three production methods, namely: *primary*, *secondary* and *tertiary* recovery. Several factors control the production flows in most oil fields. A basic understanding of these is necessary for better understanding of decline and depletion behaviour. Physically, oil recovery is about fluid flows through the porous material that make up the oil field. Fluid movements in a reservoir depend on the following factors that are explained more comprehensively by Satter *et al.* (2008):

- Depletion (leading to a decrease in reservoir pressure)
- Compressibility of the rock/fluid system
- Dissolution of the gas phase into the liquid
- Formation dip
- Capillary rise through microscopic pores
- Additional energy provided from the underlying aquifer or the overlying gas cap
- External fluid injection
- Thermal, or other, manipulation of fluid properties

2.1 Fluid flow fundamentals

The extraction of oil is to a large extent decided by physical properties related to the geological formation of the reservoir in question and the fluid characteristics of the petroleum it contains. Variations in these characteristics cause production rates to vary from field to field. An oil reservoir carries its fluid in small microscopic pores within the rock, and the term *porosity* refers to the fraction of the pore volume compared to the total bulk volume. The larger the porosity, the better the rock is at storing fluids. The pores serve both as storage and as a transmission network for fluid flows. The French physicist Henry Darcy (1856) studied fluid flow through a bed of packed sand and derived an elegant expression to describe the behaviour of the fluid, known as Darcy's law (Equation 1). The expression involves important physical properties such as the ability of the porous medium (rock in case of oil reservoirs) to permit fluid flow, its *permeability*, and the degree of internal resistance to flow

of the fluid, its *viscosity*. Viscous forces tend to influence reservoir flows of both produced and injected fluids in reservoirs under normal oil field conditions to a greater extent than gravity/capillary forces. This implies that fluids flow through porous media in parallel layers with few disruptions (i.e. laminar flow conditions) and the flow rate is proportional to the existing pressure gradient in the reservoir (Satter *et al.*, 2008). For a homogeneous rock formation, the equation is:

$$q = -\frac{kA}{\mu} \frac{\partial P}{\partial L} \quad (1)$$

Where q = volumetric flow rate [cm^3/sec], k = permeability [darcy], A = cross-sectional area [cm^2], μ = viscosity of fluid [centipoise], $\partial P/\partial L$ = pressure gradient over the length of the flow path [atm/cm]. Sand typically has a permeability of 1 darcy, but permeability are generally less for most rocks and often expressed in millidarcys. A darcy equals $0.986923 \mu\text{m}^2$ and this non-SI unit is still traditionally used in petroleum engineering and geology.

This equation is derived from a special case, where it is assumed that flow occurs in a horizontal direction without turbulence and that only one fluid is present in the pore space, which is not reacting chemically with the rock. Generally horizontal flow is greater than vertical flow due to directional differences in permeability (Selley, 1998), but this must be seen as a simplification of the real conditions in an oil field. Nevertheless it is relevant because it expresses the physical limits to the possible production rate, or defines a “*best case-scenario*” of production from a homogenous reservoir where the pressure gradient is the sole drive mechanism.

Darcy’s Law states that a fluid with high viscosity will have a low flow rate; that if the rock permeability is high there will be a high flow rate; and that there must be a pressure gradient in order to have any fluid flow. The negative sign in the expression also indicates that the flow goes in the opposite direction of the pressure gradient.¹

2.1.1 Primary recovery

Primary recovery uses naturally occurring energy, such as buoyancy (Archimedes principle) and reservoir pressure, to drive oil flows to the surface. Oil is simply allowed to flow under its own pressure, unless fluids are injected into the reservoir. However, the pressure gradient drops as oil is extracted and this will limit the rate of production according to Darcy’s law (Abrams and Wiener, 2010). This results in a depletion-driven decline in the rate of production as depletion of the reservoir reduces pressure and hence fluid flows.

Reservoir and fluid properties can greatly influence the outcome and lead to significant differences in the percentage of ‘oil in place’ that is recovered (i.e. *recovery factor*). Typically, about 10–30% of the oil in place can be extracted during primary recovery (Kjärstad and Johnsson, 2009).

2.1.2 Secondary recovery

Secondary recovery focuses on *artificial pressure maintenance* (APM), where injection of fluids maintains reservoir pressure. In most oil fields, especially those of significant size, secondary recovery accounts for the largest proportion of total recovery (Amit, 1986; Hyne, 2001). The most common method for maintaining pressure during secondary recovery is water flooding, where water is injected to maintain reservoir pressure. When this works well

¹ Darcy’s law can also be directly derived from the Navier–Stokes equations (Neuman, 1977).

the water forms a water bank that moves through the pores and presses the oil towards the producing wells.

The injection of water is generally intended to give a fairly constant pressure at the entry to a well pipe (i.e. *downhole pressure*), but eventually injected fluids will break through and mix with the oil. Conservation of mass (i.e. *material balance*) in oil reservoirs requires that the extracted volume of fluid is relatively constant throughout the lifetime (Satter *et al.*, 2008), but the water share (or ‘*water cut*’) will increase with time. This can be described by simple models, such as used by Abrams and Wiener (2010). As oil is extracted from the reservoir, an increased water cut will cause a decline of the oil production flow despite high reservoir pressure. An example of this can be seen in the Jay field (Figure 2).

Water-flooding presents numerous engineering challenges that vary with the rock and fluid properties, reservoir heterogeneities and the physical differences between the oil in place and the injected water (Satter *et al.*, 2008). One example is when the oil is much more viscous than the injected water causing so called “*fingering*”, where water moves in thin irregular ‘*fingers*’ instead of as a unified front. This bypasses significant volumes of recoverable oil and can cause premature breakthrough of water into production wells.

The properties of the oil compared to water are so important for oil extraction that the American Petroleum Institute has constructed a measure of the density of the oil compared to water, defined as API gravity = (141.5/specific gravity at 60 degrees Fahrenheit) – 131.5.

If API > 10° the oil is lighter and floats on fresh water, while if API < 10° it is denser and sinks. Water flooding is possible when the oil API > 25° and the viscosity is rather low (< 30 centipoise), and works best in homogenous reservoirs. Consequently, secondary recovery is not always effective, even though a majority of the world’s oil producing fields attempt secondary recovery. Primary and secondary recovery combined can usually extract 30–50% of the oil in place and nearly all reservoirs that can benefit from APM are using it (Kjärstad and Johnsson, 2009).

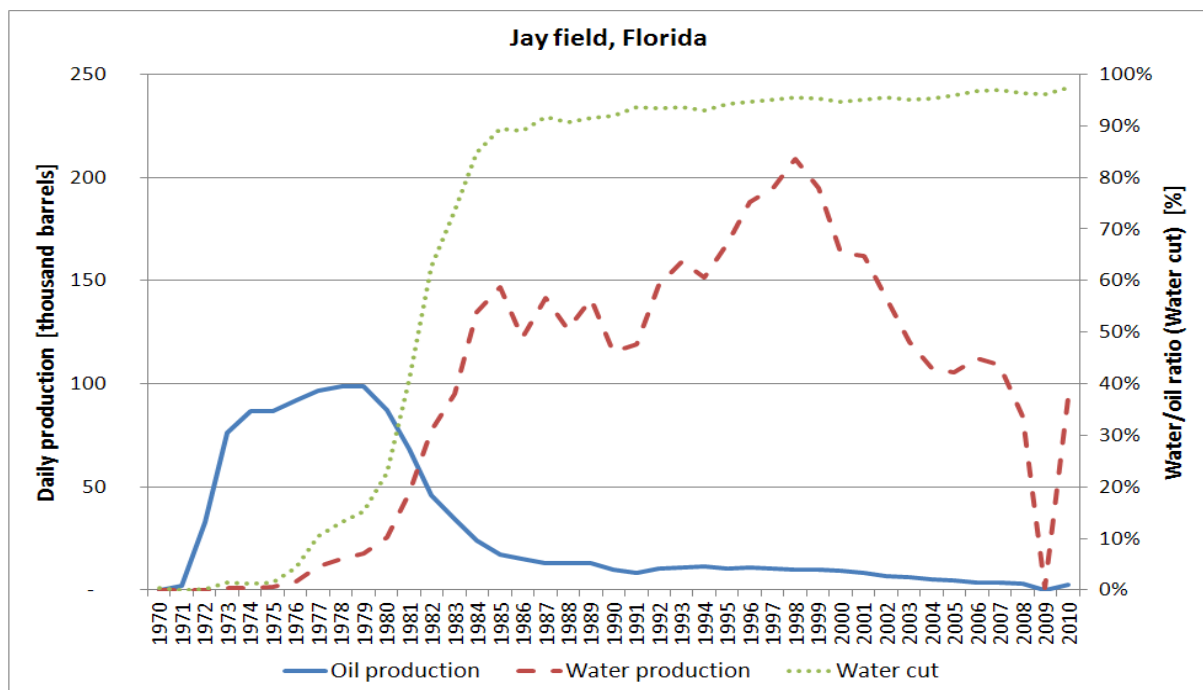


Figure 2. Production of oil and water for the giant Jay field in Florida, USA. The water cut reached over 90% of total produced fluids in the mid-1980s and is now at 97%. In 2010, the field produced 2,500 barrels of oil and 94,000 barrels of water per day. Data source: Florida Department of Environmental Protection (2012)

2.1.3 Tertiary (enhanced) oil recovery

Tertiary recovery or *enhanced oil recovery* (EOR), involves more complex ways of influencing rock and fluid properties (see Muggeridge *et al.*, this volume). The feasibility of EOR, together with the appropriate approach to EOR, will vary with the fluid properties and geological characteristics of the reservoir. According to Darcy's Law, the ability of oil to move in a reservoir can be increased by decreasing its viscosity. This leads to four main approaches to EOR, namely thermal, chemical, miscible and microbial methods.

Thermal methods are the most commonly used approach and make up nearly half of all worldwide EOR projects (Adasani and Bai, 2011). Thermal EOR involves changing oil viscosity by thermal means, such as steam flooding, hot-water flooding or in-situ combustion, where the bottom of the reservoir is ignited and heat is generated by burning a part of the oil in place (Kovscek, 2012).

Miscible methods account for about 41% of worldwide EOR projects and focus on injection of a gas or solvent that is miscible with the oil, resulting in improved recovery (Adasani and Bai, 2011). Miscibility increases the mobility of the oil, but also greatly adds to the complexity of the process (Bath, 1989). Carbon dioxide injection is widely applicable to many reservoirs at lower miscibility pressures than other methods (Satter *et al.*, 2008). Part of the carbon dioxide is soluble in oils and swells the net volume and reduces viscosity. As miscibility develops, both CO₂ and oil can flow together because of the low interfacial tension. If available, light hydrocarbons (primarily natural gas) can also be injected to generate miscibility, decrease the viscosity of the oil and increase oil volume via swelling. Nitrogen, or even flue gas, is an alternative in high permeability reservoirs containing light oil (Bath, 1989). These gases are usually rather inexpensive, but inferior to CO₂ or hydrocarbons from an oil recovery perspective (Satter *et al.*, 2008). Nitrogen has poor solubility in oil and requires much higher pressures to develop miscibility.

Chemical flooding uses the injection of polymer, surfactants, and caustic alkaline or other chemicals. At present, it makes up about 11% of global EOR projects (Adasani and Bai, 2011). This technique requires conditions favourable for water-flooding as it is a modification of water-flooding. Polymers can be used to augment water-flooding by changing water viscosity and mobility. More oil will be produced in the early life of the water flood and this is the primary economic advantage, as ultimate recovery is generally the same for as for conventional water-flooding (Satter *et al.*, 2008). Surfactants recover additional oil by enhancing mobility and solubility of oil and emulsification of oil and water. Caustic alkaline injection involves the injection of sodium compounds that can react with organic petroleum acids in certain oils to create surfactants in situ (Satter *et al.*, 2008). Injected chemicals can also react with reservoir rocks to change wettability and thereby improve recovery. Sheng (2011) reviewed these methods.

The final form of EOR uses microbes to improve oil recovery. It is a sparsely used approach and only makes up 0.6% of worldwide EOR projects (Adasani and Bai, 2011). Injected microbes can generate gas within the reservoir, thus increasing reservoir pressure and reducing oil viscosity. Alternatively microbes can generate bio-surfactants that can reduce interfacial tension and improve recovery by favourably changing wettability (Adasani and Bai, 2011).

Under favourable conditions, the combination of primary and secondary recovery can extract between one third and one half of the original oil in place. The average recovery from petroleum reservoirs around the world is estimated to be approximately 35% (Satter *et al.*, 2008). If a large part of the oil remains after both primary and secondary recovery, operators may implement a suitable EOR technique. However, only a small percentage of all oil fields are using EOR due to high costs and technology requirements (Kjärstad and Johnsson, 2009). Since 1959, only 652 EOR projects have been pursued and enhanced production

corresponded to ~1.8 Mb/d in 2010, or 1.5% of total global production (Adasani and Bai, 2011).

3. Defining decline and depletion rates

The concept of depletion is intuitive as it is something of which we all have every-day experience. For example, if we have a fixed amount of beer in a bottle, and drink some of it, the beer in the bottle is unavoidably depleted. Any resource that is extracted faster than it is produced is subject to depletion - which means that depletion is not restricted to non-renewable resources. For example, wood can be considered renewable, but if deforestation is faster than reproduction the resource is depleted within the the time-span considered. A resource can only be considered as renewable if the rate of extraction is less than or equal to the rate of increment of the resource. Fossil fuels are only reproduced on geological time-scales, making depletion of these resources irreversible for all practical purposes.

While the concept of depletion is the same for all resources, there may also be limits on the *rate* of depletion of a resource. This is an important consideration for oil resources, where the rate of depletion is constrained by geological conditions and the physical laws of fluid flow in porous media, together with economic and technological factors.

3.1 Fundamental definitions for oil depletion

A fundamental parameter concerning oil production is the size of recoverable resources remaining for exploitation. Multiple classification schemes for resources and reserves make it difficult to compare and combine data from different sources (UKERC, 2009a; Jackson and Smith, this volume). The remaining recoverable resource at time t may be expressed as:

$$R_r = URR_t - Q_t \quad (2)$$

Where R_r = remaining recoverable resource at time t , URR_t = ultimately recoverable resources (URR) estimated at time t , and Q_t = cumulative production at time t . The term reserve growth refers to the increase in the estimated URR of known fields over time and has been discussed in more detail by UKERC (2009b). Revisions to URR estimates may occur at any time as a consequence of changing market conditions, increased geological knowledge, and improved technology and so on. This makes URR a time varying quantity, although it is not as fluctuating as other reserve estimates.

URR may also be expressed as the remaining recoverable resource plus cumulative production at an arbitrary point in time. The *depletion level*, here denoted D_t , can then be defined as the fraction of the URR that has been extracted at time t :

$$D_t = \frac{Q_t}{Q_t + R_r} = \frac{Q_t}{URR_t} \quad (3)$$

Depletion levels can vary from 0 to 1 (i.e. 0–100%) and indicate what proportion of the estimated URR remains. Returning to the beer bottle analogy, we note that a half-full bottle would have a depletion level of 50%.

3.2 Depletion rates

Conceptually, the depletion rate is the ratio of annual production to some estimate of recoverable resources, where the latter can be defined as 1P or 2P reserves, remaining recoverable resources or the URR (see UKERC (2009a) or Jackson and Smith (this volume)). A lack of standardized use has resulted in several studies using depletion rates based on very

different definitions of recoverable resources and this has added to the confusion surrounding the concept.

In practice, a depletion rate can refer to two possible things. Firstly, it can relate to the rate of change of the depletion level at time t . Secondly, it could also refer to the rate at which remaining recoverable resources are being produced. Unclear definitions have led to confusion surrounding this parameter. This study will differentiate these two definitions by denoting them as *depletion rate of URR (URR depletion rate)* and *depletion rate of remaining recoverable resources (RRR depletion rate)*, respectively.

The *depletion rate of URR*, here denoted $d_{URR,t}$, is the time derivative of the depletion level. This parameter is easily calculated if one has access to URR estimates and reflects how much of the URR is extracted annually. For example, Saudi-Aramco (2004) used a very similar definition when they gave annual depletion rates (expressed as % of initial proved reserves) for some selected fields. If q_t denotes annual production, one obtains the following expression:

$$d_{URR,t} = \frac{q_t}{URR_t} \quad (4)$$

In addition, a measure of how fast remaining recoverable resources are depleted is of interest. The depletion rate of the remaining recoverable resource, $d_{RRR,t}$, is given by:

$$d_{RRR,t} = \frac{q_t}{R_r} = \frac{q_t}{URR_t - Q_t} \quad (5)$$

Furthermore, this parameter can also be expressed as a *production-to-reserve ratio* (P/R), since it is the reciprocal of the widely used *reserves-to-production ratio* (R/P). However, one must mind the underlying definitions as R/P ratios are often based upon 1P reserve estimates, while most applications of depletion rates use 2P data.

$$d_{RRR,t} = \frac{\text{production}}{\text{remaining recoverable resources}} = \frac{q_t}{R_r} = \frac{1}{\frac{R_r}{q_t}} \quad (6)$$

This parameter is useful since it can directly be estimated from commonly available data, such as reported remaining reserves and historical production (Jakobsson *et al.*, 2009). The $d_{RRR,t}$ -parameter has also been called *depletion rate of remaining reserves* and various similar expressions in published studies, but caution should be exercised depending on the definition of recoverable resources.

3.3 Decline rates

The rate of decline, λ , is equal to the difference in the rate of production from one period to the next (see Equation 7) and is commonly expressed on an annual or monthly basis. Changes can be both positive and negative, but are generally negative after a field has passed its peak of production.

$$\lambda_t = \frac{\text{Change in production rate}}{\text{Production rate}} \quad (7)$$

A disadvantage of decline rate studies is that they do not necessarily relate to the physical factors driving oil depletion (decreasing reservoir pressure, increasing water cut, etc.). Observed decline may also arise from non-physical factors such as underinvestment,

politics, production quotas, damage or sabotage. In essence, decline rates easily provide ambiguous signals for unwary analysts. Usually, decline of production is the result of complex interactions between reservoir physics, technology, economics and decision-making. Many factors influence production rates and one must be careful in extrapolating decline into the future.

Decline and disruption caused by socioeconomic events are often termed ‘above-ground’ constraints, and may be resolved if proper measures are taken. On the other hand, depletion-driven decline is the result of intrinsic, below-ground physical constraints and is difficult to alleviate. Since the early days of the petroleum industry, increasing exploitation and depleting reserves have been related to declining production (Satter *et al.*, 2008). *Decline curve analysis* has long been a tool for predicting field behaviour.

3.3.1 Decline curve analysis

The decline rate can also be expressed using derivatives with q = production rate in arbitrary units and t = time in arbitrary units. The solution to the arising differential equation allows decline characteristics to be expressed using the decline rate (λ_t), its exponent (β) and a constant denoted C (Satter *et al.*, 2008):

$$\lambda_t = -\frac{\dot{q}}{q} = -\frac{dq}{dt} = Cq^\beta \quad (8)$$

Originally introduced by Arps (1945; 1956), decline curve analysis is a simple tool to model and predict future production under the assumption that depletion is the driving decline mechanism. Decline can be constant ($\beta = 0$), directly proportional to production rate ($\beta = 1$), or proportional to a fractional power of the production rate ($0 < \beta < 1$).

In decline curve models, it is assumed that production begins to decline at time t_0 , with an initial production rate of q_0 and an initial cumulative production of Q_0 . The production rate at time $t \geq t_0$ is denoted by $q(t)$ and the cumulative production between t and t_0 is given by the integral $Q(t) = \int_{t_0}^t q(t) dt$. The simplest decline curves are characterized by three parameters: the initial production rate $q_0 > 0$, the initial decline rate $\lambda_0 > 0$ and the exponent $\beta \in [0,1]$. If the production is allowed to continue perpetually and the integral $Q(t) = \int_{t_0}^t q(t) dt$ converges to a single value as $t \rightarrow \infty$, it is possible to calculate the cumulative production over the decline phase. This can then be added to q_0 to give an estimate of the fields’ URR.

A more general presentation of decline curves can be found in Chang and Lin (1999), Höök *et al.* (2009c) and Khanamiri (2010). The general case is a hyperbolic decline curve ($0 < \beta < 1$), while exponential decline ($\beta = 0$), is an important special case due to its simplicity and ease of use. Their key properties can be seen in Table 1. Harmonic decline ($\beta = 1$), is another important special case of the hyperbolic decline curve, not described in detail here.

Decline curves should be seen as more than mathematical curve-fitting exercises since they have a sound physical basis. For example, exponential decline curves represent the solution to the physical flow equation of a homogenous field with a given initial drive pressure that reduces as the oil is extracted (Hurst, 1934; van Evendingen and Hurst, 1949). This connects decline curve models with the depletion-driven production declines caused by the exhaustion of recoverable resources. Although decline curve analysis was originally developed for single wells, it can also be applied to entire fields (Satter *et al.*, 2008). However, the time distribution of active wells as well as temporary shutdowns and similar

events will also influence the production profile and hence complicate the connection between observed decline and underlying driving forces.

Initial production decline is often exponential, although behaviour tends to flatten out towards hyperbolic or harmonic decline further out in the tail region. Hyperbolic decline gives longer well life and leads to larger URR values. An example of fitted decline curves can be found in Figure 3. Incorrect choice of decline curve can lead to flawed estimates if the curve is used to estimate URR.

Table 1. Key properties of hyperbolic and exponential decline curves of Arps type

	Hyperbolic	Exponential
β	$0 < \beta < 1$	$\beta = 0$
$q(t)$	$q_0[1 + \lambda_0\beta(t - t_0)]^{-1/\beta}$	$q_0 \exp(-\lambda_0(t - t_0))$
$Q(t)$	$Q_0 + \frac{q_0}{\lambda_0(1 - \beta)} \left[1 - \left(1 + \lambda_0\beta(t - t_0)^{1 - \frac{1}{\beta}} \right) \right]$	$Q_0 + \frac{q_0}{\lambda} (1 - \exp(-\lambda_0(t - t_0)))$
URR	$Q_0 + \frac{q_0}{\lambda_0(1 - \beta)}$	$Q_0 + \frac{q_0}{\lambda_0}$

Decline curve extrapolations require no detailed reservoir data, such as oil saturation or local permeability, and can easily be done from only production data, which is comparatively easy to acquire. They can also be used to estimate ultimate recovery of fields via curve-fitting. Consequently, decline curve projections are often used when analysing single fields or in bottom-up studies of oil depletion that sum up the production from individual fields.

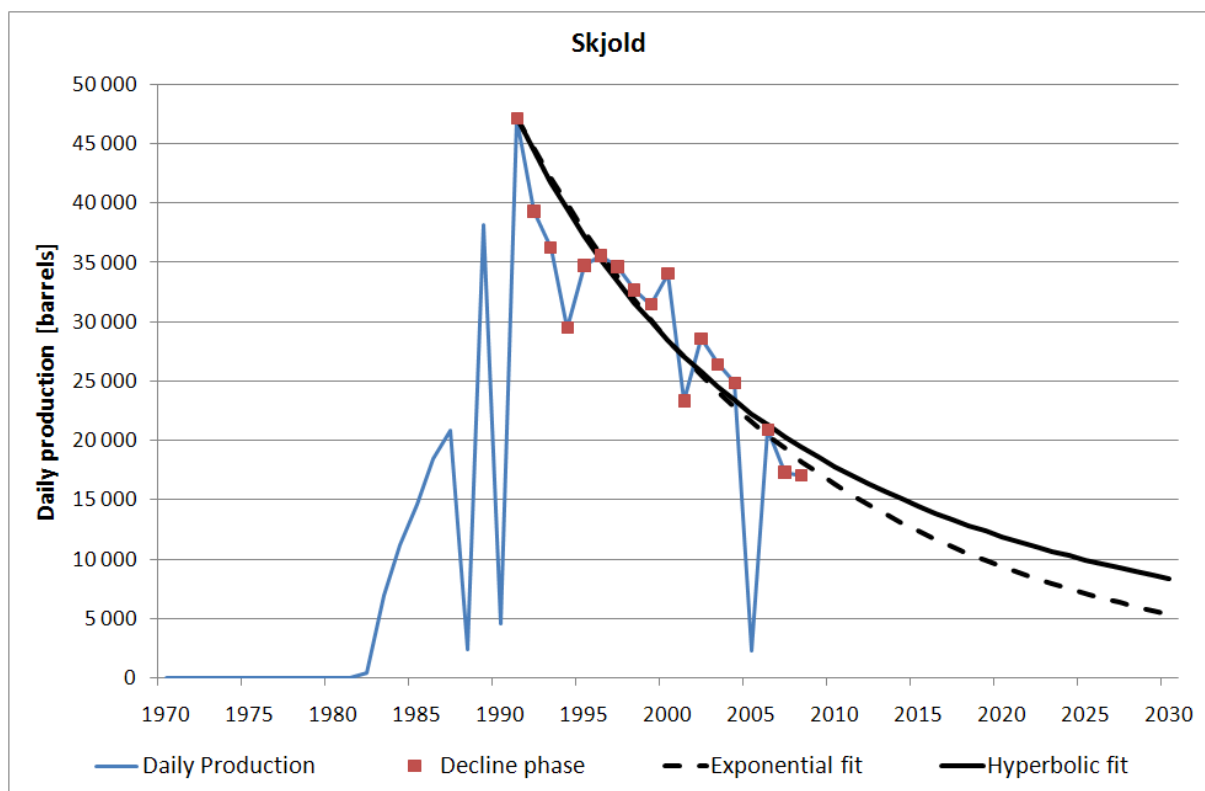


Figure 3. The Danish oil field Skjöld with both exponential and hyperbolic decline curve fits. Source: Höök et al. (2009c).

3.4 Depletion rates after the onset of decline

Depletion-driven production decline via reservoir mechanisms and decline curve analysis have some interesting properties that arise when they are combined. Depletion rates generally increase with increasing extraction before the decline phase is reached. In the exponential case, it can be shown that the depletion rate of remaining resources during the decline phase is equal to the decline rate. Inserting the expressions for production, cumulative production and URR for the exponential curve (Table 1) into the equation for the depletion rate of remaining recoverable resources ($d_{RRR,t}$), leads to:

$$d_{RRR,t} = \frac{q_0 \exp(-\lambda(t - t_0))}{\left(Q_0 + \frac{q_0}{\lambda}\right) - \left(Q_0 + \frac{q_0}{\lambda}(1 - \exp(-\lambda(t - t_0)))\right)} \quad (9)$$

This can be simplified to:

$$d_{RRR,t} = \frac{\lambda * \exp(-\lambda(t - t_0))}{\exp(-\lambda(t - t_0))} = \lambda \quad (10)$$

Consequently, having an estimate of $d_{RRR,t}$, prior to the onset of decline makes it possible to estimate the subsequent decline rate, provided the field can be assumed to follow exponential decline. In practice, fields tend to divert from exponential decline and move toward a more hyperbolic or harmonic decline curve as production heads further out into the tail region.

The second definition of the depletion rate of URR (Equation 4) yields a more complicated expression that cannot be additionally simplified:

$$d_{URR,t} = \frac{q_0 \exp(-\lambda(t - t_0))}{\left(Q_0 + \frac{q_0}{\lambda}\right)} \quad (11)$$

Since q_0 , Q_0 and λ all are constants and the exponential expression is strictly decreasing, it follows that the depletion rate of URR will be decreasing as the oil field enters the decline phase. It also holds that the maximum value of $d_{URR,t}$ must occur before the fields reaches the onset of decline.

It should also be mentioned that exponential behaviour is a simplified form of decline and that the general situation tends to be hyperbolic in nature. This makes it interesting to study how the two depletion rates behave in a hyperbolic decline situation. Once again, combining the definition of $d_{RRR,t}$ (Equation 5) and the functions for production, URR and cumulative production in the hyperbolic case (Table 1) yield:

$$d_{RRR,t} = \frac{q_0 [1 + \lambda\beta(t - t_0)]^{-1/\beta}}{\left(Q_0 + \frac{q_0}{\lambda(1 - \beta)}\right) - \left(Q_0 + \frac{q_0 [1 - (1 + \lambda\beta(t - t_0))^{1-1/\beta}]}{\lambda(1 - \beta)}\right)} \quad (12)$$

Simplifying this gives an expression that is decreasing with time:

$$d_{RRR,t} = \frac{\lambda(1 - \beta)}{1 + \lambda\beta(t - t_0)} \quad (13)$$

In contrast, the definition of $d_{URR,t}$ (Equation 4) and the functions for production, URR and cumulative production in the hyperbolic case (Table 1) give:

$$d_{URR,t} = \frac{q_0[1 + \lambda\beta(t - t_0)]^{-1/\beta}}{\left(Q_0 + \frac{q_0}{\lambda(1-\beta)}\right)} = \frac{1}{\left(Q_0 + \frac{q_0}{\lambda(1-\beta)}\right)(q_0[1 + \lambda\beta(t - t_0)]^{1/\beta})} \quad (14)$$

One should note that $\beta \in [0,1]$, making the power generally negative. All together, the expression for $d_{URR,t}$ will also be strictly decreasing with time as $t \rightarrow \infty$.

The expressions for depletion rates of both remaining resources ($d_{RRR,t}$) and ultimate resources ($d_{URR,t}$) in the hyperbolic case imply that a *maximum depletion rate* must be reached before the onset of decline. This holds for single wells, described by a single decline curve, as well as for entire fields consisting of many declining wells distributed in time. But some caution should be exercised regarding fields, as obfuscating factors of a non-physical nature such as temporary shutdowns or redevelopments may influence production.

The maximum depletion rate occurs just before the onset of decline, which can be shown analytically for wells or fields perfectly described by decline curves. In practice, the maximum depletion rate typically occurs around the peak production with some dependence on the definition of recoverable resources.

A real world illustration can be made from the Norwegian giant field Norne (Figure 4). The exponential decline curve provides a good fit to observed production and can also be used to estimate the URR, giving reasonable agreement with the official figure provided by the Norwegian Petroleum Directorate. The value of $d_{URR,t}$ reaches a maximum at the peak production, while $d_{RRR,t}$ based on the estimated URR does the same. When using the official URR, $d_{RRR,t}$ remains stable after the peak production with some oscillations around its maximum in reasonable agreement with theory. Investigating these parameters empirically in a larger dataset is the next step.

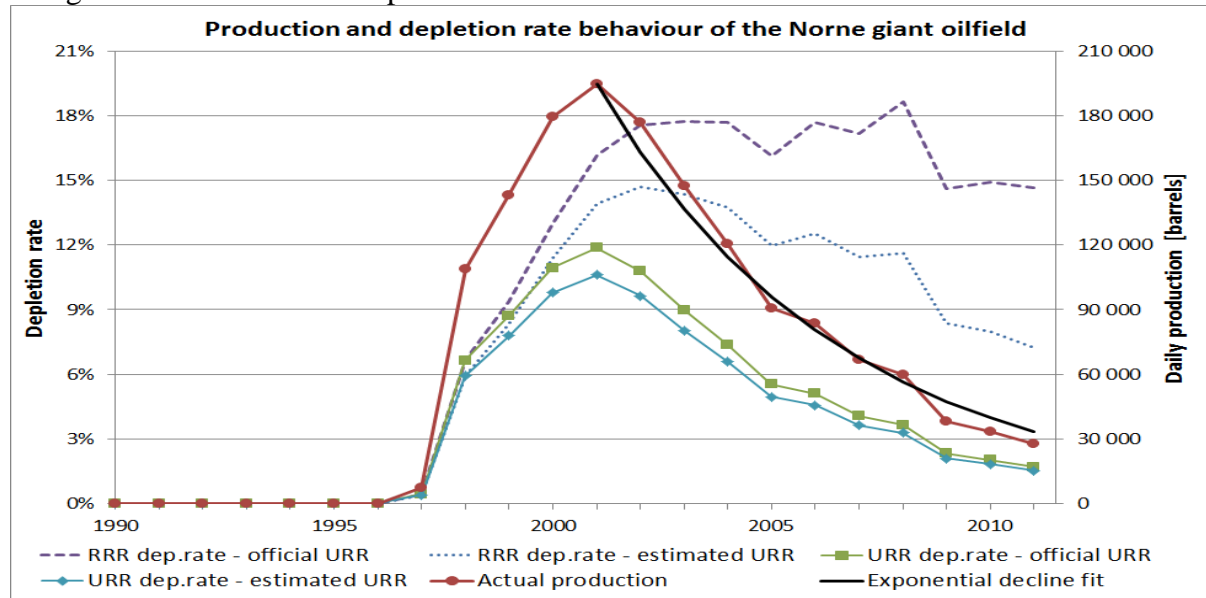


Figure 4. Production and depletion rate behaviour in the Norne giant oil field in Norway. The official URR estimate (0.60 Gb) was taken from the NPD fact pages (<http://factpages.npd.no/factpages/>), but includes economic considerations lowering the recoverable volume compared to an estimated URR (0.67 Gb) obtained using an exponential decline curve. Nevertheless, the RRR depletion rate remains stable or decreases.

3.5 Depletion rates for regions

Any oil region, such as a province, nation or a group of nations, consists of an arbitrary group of oil fields. A region contains n fields, where some may be in production while others are yet to be found. First, some definitions are needed. Let $URR_{reg,t}$ denote the aggregate estimated URR in a region with n fields while Q_{reg} refers to the aggregate cumulative production, and q_{reg} equals the aggregate annual production in the same region at time t . The regional URR at a given time is almost certainly larger than the URR of known producing fields, because of a contribution from unknown fields yet to be found. Regional production at a given time consists of the aggregated output from known fields plus a zero contribution from the undiscovered fields.

If $Q_{n,t}$ is the cumulative production of field n at time t , then the depletion level of the region ($D_{URR,t}$) may be defined as:

$$D_{URR,t} = \frac{Q_{reg,t}}{URR_{reg,t}} = \sum_1^n \frac{Q_{n,t}}{URR_{reg,t}} \quad (15)$$

The depletion rate of URR in a region is the next thing to delineate. If $q_{n,t}$ denotes annual production of field n one can now define it as:

$$d_{URR,t} = \frac{q_{reg,t}}{URR_{reg,t}} = \sum_1^n \frac{q_{n,t}}{URR_{reg,t}} \quad (16)$$

Finally, the depletion rate of remaining recoverable resources is defined as follows:

$$d_{RRR,t} = \frac{q_{reg,t}}{URR_{reg,t} - Q_{reg,t}} = \sum_1^n \frac{q_{n,t}}{URR_{reg,t} - Q_{reg,t}} \quad (17)$$

A maximum depletion rate for individual fields also indicates the existence of a maximum depletion rate on both regional and global scales, as the regional depletion rate is just a weighted average of the individual subparts. From this it follows that the regional depletion rates must lie somewhere between the smallest (0% if undiscovered fields are considered) and largest depletion rates for its individual fields, regardless of whether one uses depletion rates of URR or remaining recoverable resources. Thus, depletion rates of individual fields and the temporal distribution of field production profiles become the principal factors that determine the regional depletion rate.

The extreme situation would be if all fields reached their maximum depletion rates simultaneously, in which case the regional value would also be at a maximum, although not the same numerical value. However, this is not likely to happen in reality as fields are usually at different stages of development at any given point in time. Larger regions, such as the world, will never develop uniformly and some subparts will be developed in the beginning, while others will remain undeveloped for a long time. Such patterns will give more temporally dispersed fields, yielding lower regional depletion rates.

The timing of production from a particular field is determined by the year of discovery, available extraction technology, administrative barriers and macroeconomic circumstances, to name a few factors. Therefore no analytical expression for the temporal

distribution of fields can be found. Consequently, the estimation of regional depletion rates must chiefly rely on empirical experience of how regions generally develop.

4. Empirical study

This study relies on the Uppsala giant oil field database. The database was initiated by Robelius (2007) and later updated by Höök *et al.* (2009a, b). It contains ~350 giant oil fields worldwide accounting for an URR of over 1100 Gb. For the purpose of this study, complementary data on hundreds of smaller oil fields all over the world have been combined with the giant oil field data. From this combined database, some 880 individual oilfields were selected. They were chosen to reflect the wide array of field sizes, production strategies, and socioeconomic conditions seen over the globe. The size distribution is given in Table 2, and in general an equal number of fields in each size category have been chosen. However, due to the limited number of post-peak fields larger than 1 billion barrels (Gb), this size category contains fewer fields (N=130) than the other categories (N=150). However, this difference is assumed to be negligible when identifying the general patterns of behaviour.

Table 2. *Descriptive statistics of the sample of fields studied. The distribution is highly skewed with most resources concentrated in relatively few giant fields.*

Field size URR [Mb]	Number of fields	Median size [Mb]	Mean size [Mb]
$x < 0.1$	150	0.02	0.03
$0.1 < x < 1$	150	0.4	0.4
$1 < x < 10$	150	2.9	3.9
$10 < x < 100$	150	37.9	44.4
$100 < x < 1000$	150	567.5	537.1
$x > 1000$	130	2087.5	4575.6
<i>All fields</i>	880	9.1	775.9

4.1 Data considerations

To assess depletion and decline rate behaviour, data for individual fields is essential. Some data on production and recoverable resources is available in the public domain or can be obtained from companies (IHS, Rystad Energy, etc.), agencies or governments. Some regions, such as the North Sea, provide excellent openly accessible data while others, such as OPEC, are characterized by generally poor data access.

Annual or monthly production data is comparatively easy to acquire and can commonly be obtained from operators, agencies or third-party sources such as business magazines, trade journals, etc. Recoverable resources, reserve estimates, and related data are more problematic to acquire and are generally less reliable. The multiple classification schemes for resources and reserves make it difficult to compare and combine data from different sources (UKERC, 2009a).

Naturally, there are shortcomings in the available data. For example, different definitions among reporting agencies, changing classifications over time, terrorist strikes, major accidents (Piper Alpha, Deepwater Horizon, etc.), and political decisions can all influence both production trends and data quality. Fields with severely disturbed behaviour or otherwise dubious properties were, as far as possible, omitted from this analysis. Some fields exhibit a clear peak, commonly quite early in the field's life, followed a decline phase. Other fields can have long plateau phases, possibly ranging for decades, which are followed by the onset of decline.

This study focuses on fields that have “peaked” and left the plateau stage. Consequently, fields that are in the build-up phase or haven’t reached the onset of decline are excluded from the study. For fields with a plateau, “peaking” was defined as the point where production is judged to clearly leave a 4% fluctuation band around the plateau level, as earlier used by Höök *et al.* (2009b).

The data show a strong correlation ($R^2 = 0.98$) between estimated URR and peak/plateau production levels (a power fit indicates a strong correlation valid over several magnitudes as seen in figure 5). This is hardly surprising, since high daily production levels are generally only possible in fields with significant URR.

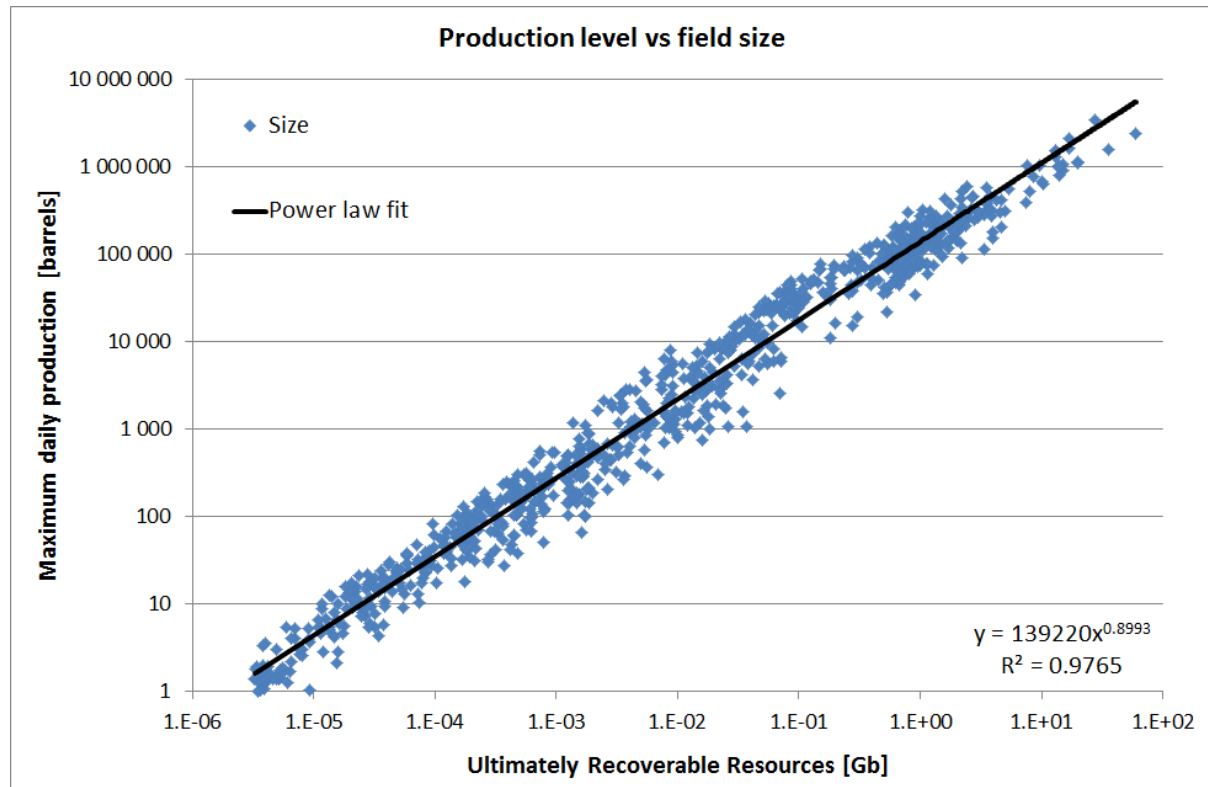


Figure 5. The relation between field size and maximum production level.

4.1.1 Specific notes on field sizes

For some fields, official estimates of URR or equivalent were available. For others, the URR was estimated by adding cumulative production to recent (no older than 2005) industry estimates of 2P (proven+probable) reserves. Bentley *et al.* (2007) discuss industry 2P data in more detail and suggest that they provide a median estimate of remaining recoverable resources (i.e. there is a 50% probability that recoverable resources are higher or lower). Thus it is equally likely that cumulative production over the remaining life-time of the field will be greater or lower than the 2P figure. However, reserve estimates tend to increase over time, a phenomenon known as reserve growth (Sorrell *et al.*, 2012). Factors such as increased investment, technology and knowledge are also acknowledged and known to increase reserves over time, making it probable that URR estimates based upon current 2P reserves will underestimate the actual field size, and the fact of reserves growth must also be acknowledged even in 2P data. For the remainder where no 2P data or official URR estimates were available, more traditional curve-fitting methods were used to estimate the URR.

In our aggregated dataset, the URR of some fields are surely overestimated, while others may be underestimated. We assume here that these effects cancel each other out when combined. For the sake of simplicity we assume here that a field’s URR remains fixed over

time. Changed URR values will not affect decline rates of any of the fields used in this study, and neither will it affect the peak production points. However, increases in the estimated URR reduce the estimated depletion level and depletion rate.

4.2 Decline rate behaviour

Decline rates seen in real fields can vary significantly. In this dataset, annual decline rates ranged from less than 1% to more than 70%, although the range decreases with increasing field size (Figure 6). The average decline rates for the entire data set can be derived, although such a figure can be misleading due to the underlying size dependence. Closer analysis shows major differences among decline rates and implies that decline rates of small fields may differ significantly from those of large fields (Table 3).

Giant fields of over 1 Gb have by far the lowest decline rates and there is a clear trend towards more rapid decline with decreasing field size (Table 3). Production-weighted (PW) average values also show that fields with high production levels tend to decline somewhat faster than the arithmetic average for small fields (<0.1 Gb), while the opposite was true for semi-giant and giant oil fields. Partly this can be explained by a large share of OPEC control among the larger fields and the fact that OPEC producers tend to aim for long and stable production profiles rather than rapid return on investment. Secondly, these patterns can arise from the economically rational behaviour of a price-taking producer who maximizes profit subject to technical and physical constraints (Jakobsson *et al.*, 2012).

Table 3. Observed annual decline rates in percent sorted by field size.

Field size [Mb]	Median	Mean	Production-weighted mean	Standard deviation
$x < 0.1$	-20.5	-24.0	-27.4	13.4
$0.1 < x < 1$	-17.7	-19.2	-23.0	10.6
$1 < x < 10$	-11.6	-16.7	-25.2	13.4
$10 < x < 100$	-13.5	-15.4	-18.9	9.9
$100 < x < 1000$	-7.5	-9.2	-9.2	6.1
$x > 1000$	-4.3	-5.2	-4.9	3.4
<i>All fields</i>	-12.3	-15.2	-6.2	11.9

Earlier studies have also shown that technological development such as EOR can result in more rapid declines. Gowdy and Julia (2007) initially highlighted this problem for two North Sea giant fields. Later, Höök *et al.* (2009a, b) elaborated on this and found a general tendency towards higher decline rates for giant fields as new technology and modern production strategies allowed the extension of plateau production at the expense of higher subsequent decline rates.

Table 4 compares the results of three studies that provide estimates of average decline rates from a globally representative sample of post-peak giant fields. Despite differences in data sets, definitions and weighting methods, the results are in broad agreement that the decline in the existing production is between 4–8% annually (Höök *et al.*, 2009b). Expressed in production capacity, this means that roughly a new North Sea (~5 Mb/d) has to come on stream every year just to keep the present output constant (Fantazzini *et al.*, 2011). This implies that nearly 5 new Saudi-Arabias would be needed by 2030 just to offset the decline in existing production (Alekklett *et al.*, 2010).

Höök *et al.* (2009b) provides additional data on the time evolution of giant oil field decline rates and finds the average decline rate has increased by around 0.15% per year since

mid-1960s - a trend that is expected to continue. From Table 3, it can be also seen that decline rates are higher for smaller fields and as future production becomes more reliant on non-giant fields it is reasonable that average decline in existing production will increase. The increasing decline rate is seldom discussed – even though it can lead to additional capacity requirements of as much as 7 Mb/d by 2030 (Alekklett *et al.*, 2010).

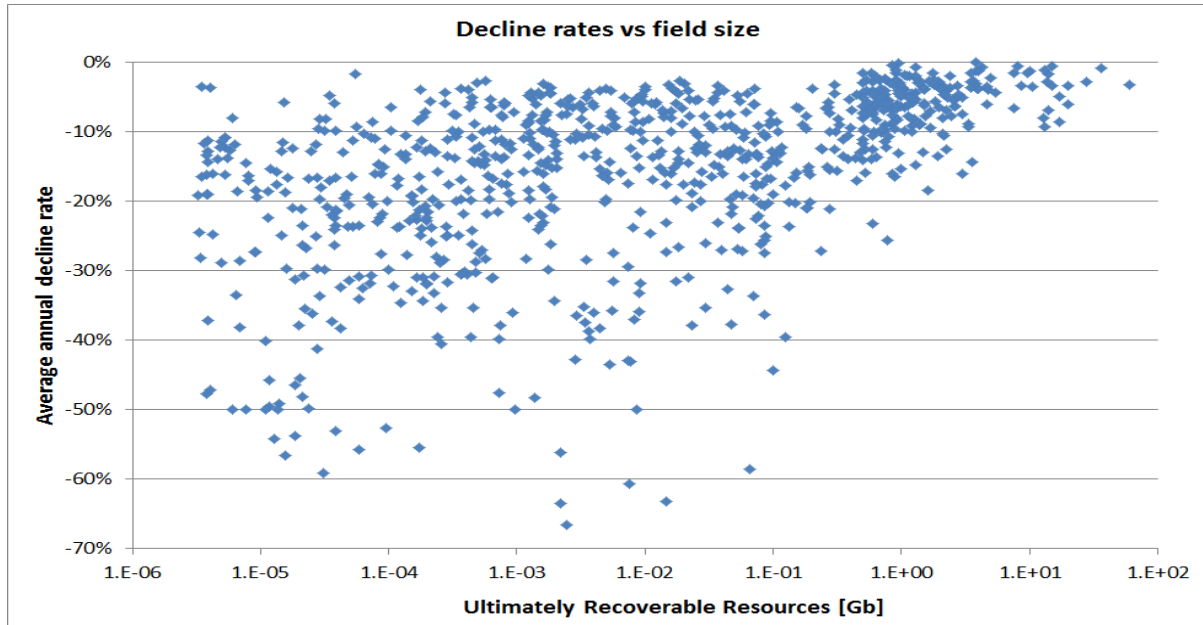


Figure 6. Scatter plot of observed decline rates seen the data set. Significant differences occur, but generally decrease with increasing field size.

Table 4. Average decline rates for post-peak giant fields found by recent studies. Source: Höök *et al.* (2009b)

Parameter	Höök <i>et al.</i>	IEA	CERA
Average decline [%]			
Total	6.5	n.a	6.3
Land	4.9	n.a	5.3
Offshore	9.4	n.a	7.5
Non-OPEC	7.5	n.a	6.4
OPEC	4.8	n.a	5.4
Production-weighted decline [%]			
Total	5.5	6.5	5.8
Land	3.9	5.6	n.a
Offshore	9.7	8.6	n.a
Non-OPEC	7.1	7.4	n.a
OPEC	3.4	4.8	n.a

4.3 Depletion level behaviour

Earlier studies have shown that it is common for giant oil fields to reach the onset of decline when less than half of the URR has been produced (Höök *et al.*, 2009a). In this study, this analysis is expanded to include smaller fields. Figure 7 provides a scatter plot of the estimated depletion level at the onset of decline, while Figure 8 provides a corresponding frequency histogram.

A significant spread can be seen among the fields studied with some reaching an estimated depletion level of over 80% before the onset of decline, while others peak at depletion levels as low as 10%. However, there is a clear trend towards higher depletion levels at peak with increasing field size (Table 5). Some of the fields with the highest depletion levels at peak, especially in the >100 Mb size category, are old American fields that were extensively redeveloped around the 1980s when new technology/investments allowed larger fractions of the oil-in-place to be recovered. Production-weighted figures indicate that fields with high annual production rates are usually developed in such a way that the depletion level is relatively high at the onset of decline.

Interestingly, there is virtually no correlation (linear correlation coefficient = -0.07) between the estimated depletion levels at peak and the subsequent decline rates in oil fields. This indicates that depletion levels have restricted relevance for analysing production flows.

It should also be noted that any future reserve growth in the studied fields will reduce the estimated depletion levels. If a significant portion of the URR figures used in this study are underestimates, the depletion levels derived here will be overestimates. If so, this would reinforce the conclusion that most fields begin to decline well before half of their URR is produced.

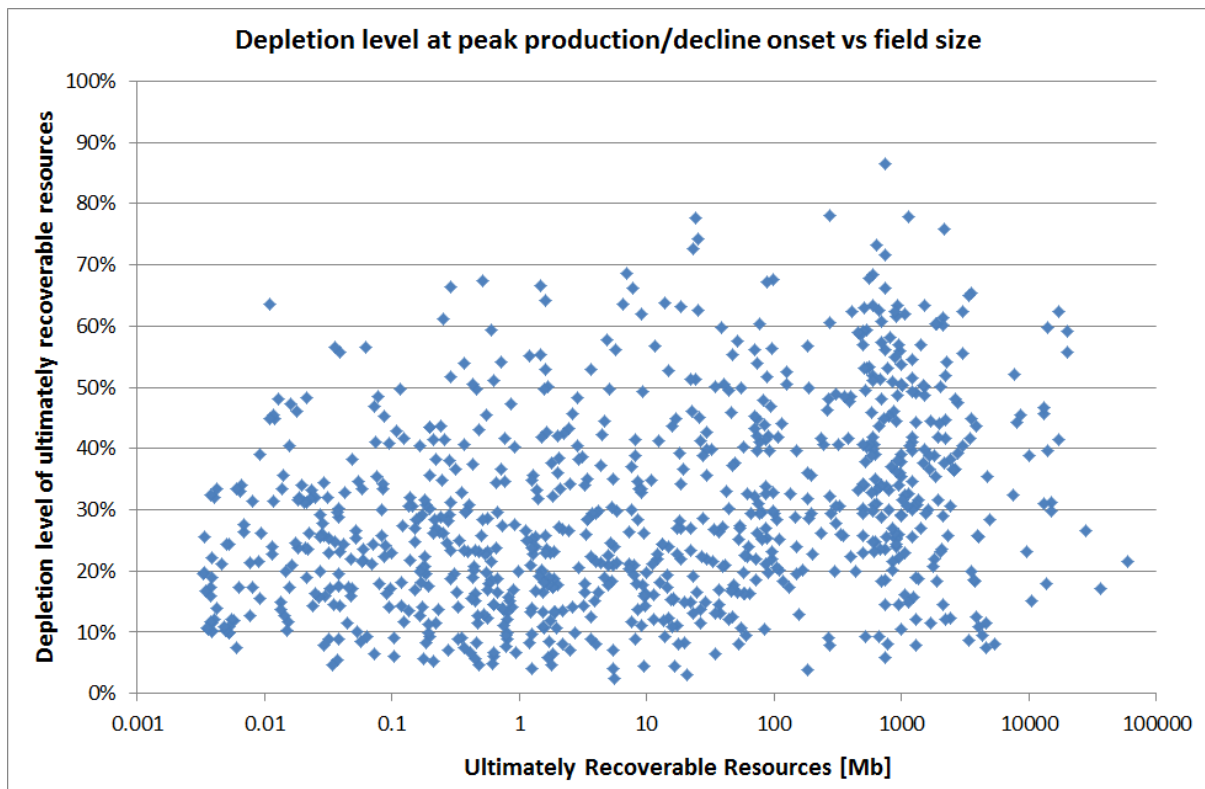


Figure 7. Scatter plot of estimated depletion levels at peak production (onset of decline).

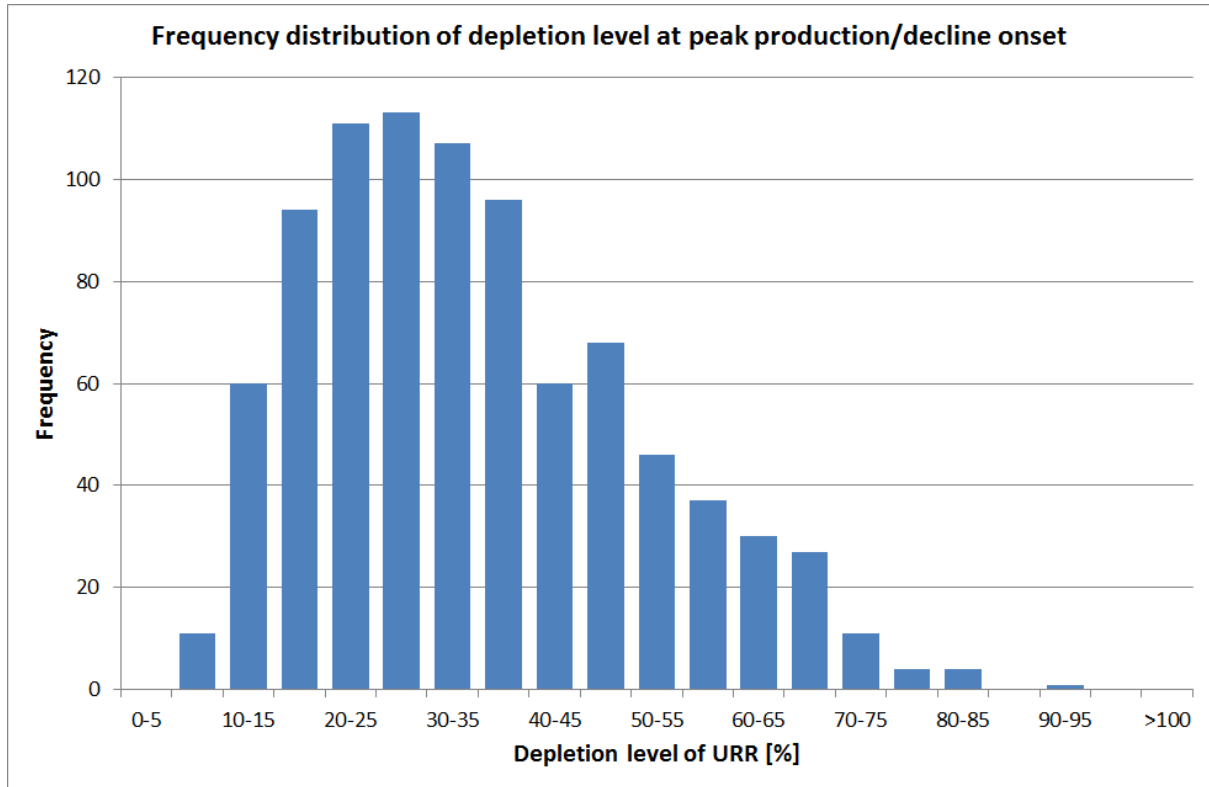


Figure 8. Frequency distribution of estimated depletion levels at peak (onset of decline).

Table 5. Estimated depletion levels at peak production sorted by field size.

Field size [Mb]	Depletion level at peak production			
	Median	Mean	Production weighted mean	Standard deviation
$x < 0.1$	23.4%	24.5%	27.2%	11.9%
$0.1 < x < 1$	22.5%	24.6%	26.0%	13.9%
$1 < x < 10$	23.1%	26.6%	28.6%	15.0%
$10 < x < 100$	27.0%	30.7%	31.6%	16.4%
$100 < x < 1000$	35.9%	38.1%	37.2%	16.4%
$x > 1000$	36.6%	36.1%	36.0%	16.0%
All fields	27.0%	29.9%	36.1%	15.9%

4.4 Depletion rate behaviour

The theory described above predicts that maximum depletion rates should occur when the onset of decline is reached. This may also be referred to as the *depletion rate at peak* and effectively marks the point where depletion-driven decline begins to dominate over other variables and leads to the onset of production decline.

Estimated annual depletion rates of URR at the onset of decline are plotted in Figure 9. A few small fields reach depletion rates of 30% or more before peaking, but most have significantly lower depletion rates at peak production. The histogram (Figure 10) shows a skewed distribution with the largest number of fields having values of 10% or less, leading to an overall mean of 10.3% and a production-weighted mean of 4.9%. The figure also demonstrates a clear trend towards lower depletion rates at peak with increasing field size (Table 6).

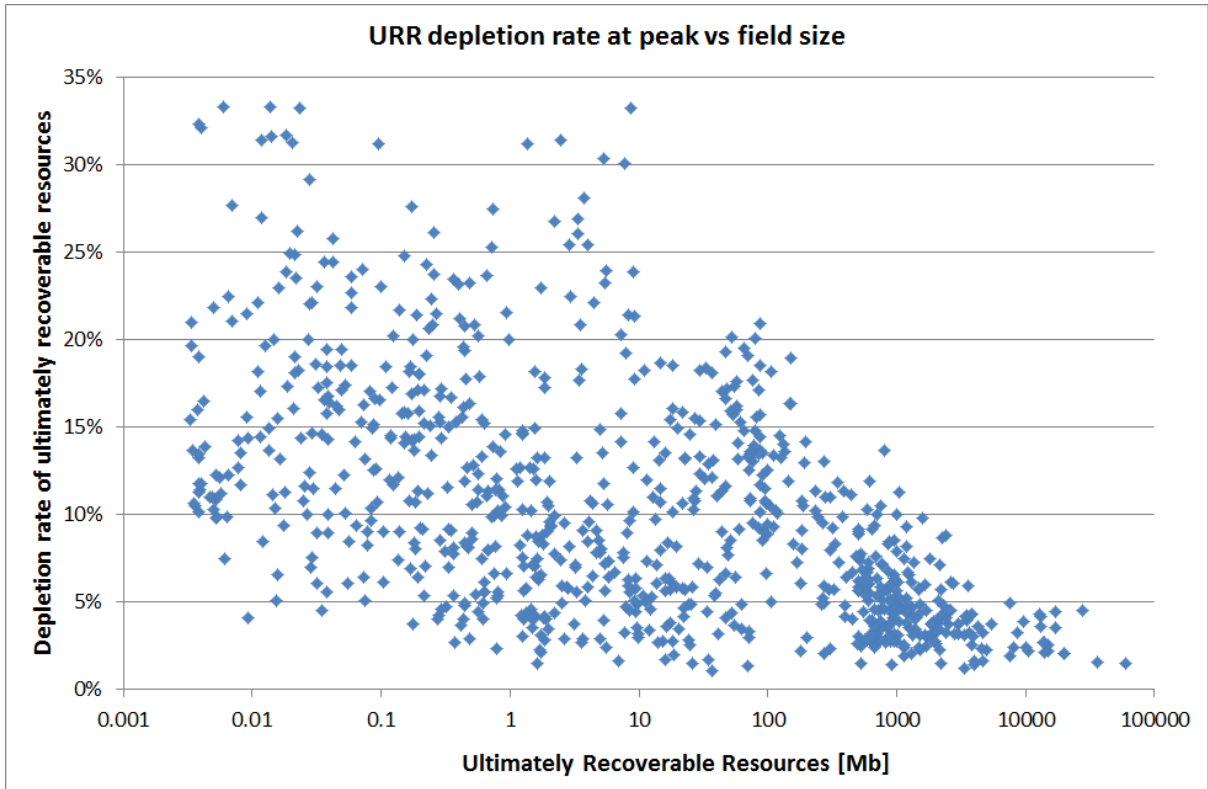


Figure 9. Scatter plot of estimated depletion rates of ultimately recoverable resources at the onset of decline.

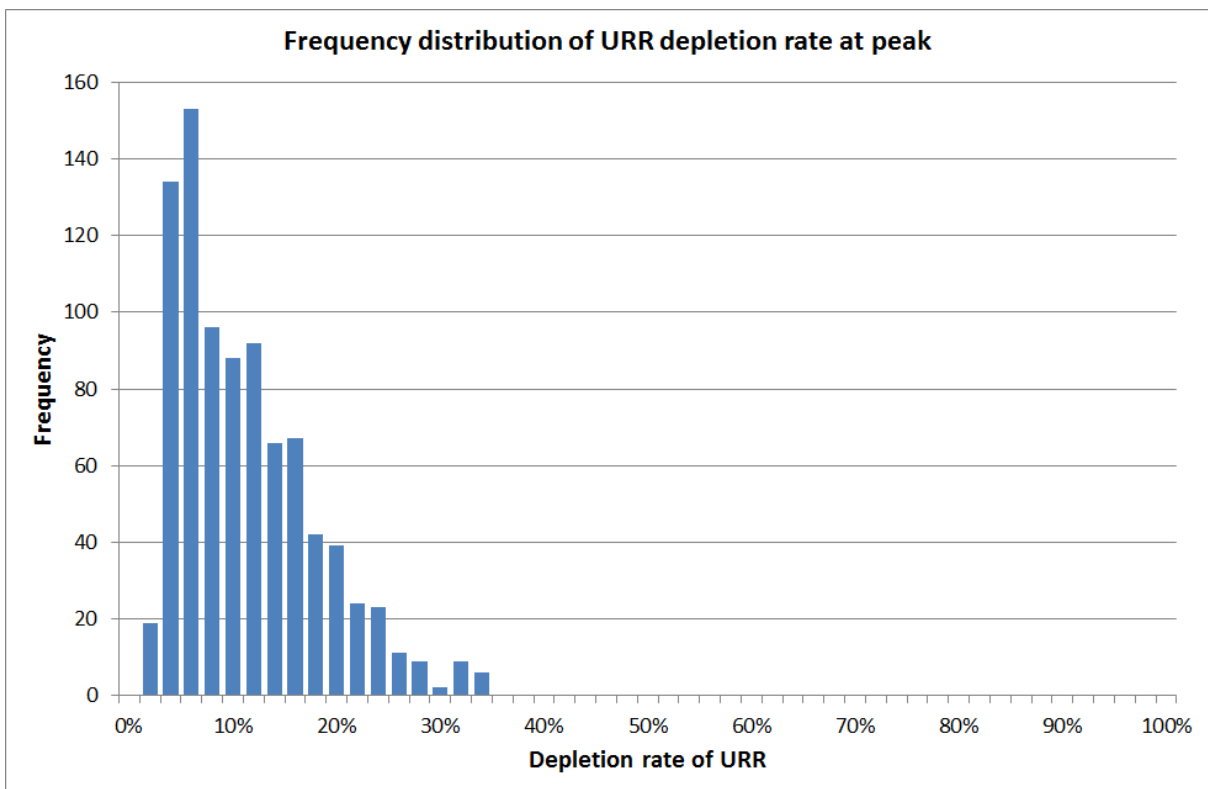


Figure 10. Frequency distribution of URR depletion rates at peak production/decline onset.

Table 6. *Estimated depletion rates of ultimately recoverable resources at onset of decline, sorted by field size.*

Field size [Mb]	Depletion rate at peak			
	Median	Mean	Production-weighted mean	Standard deviation
$x < 0.1$	15.0%	16.1%	18.4%	6.9%
$0.1 < x < 1$	12.1%	12.9%	15.3%	6.1%
$1 < x < 10$	8.2%	10.5%	16.5%	7.4%
$10 < x < 100$	10.8%	10.4%	13.5%	5.2%
$100 < x < 1000$	6.0%	6.8%	7.3%	3.6%
$x > 1000$	3.8%	4.2%	4.0%	1.9%
<i>All fields</i>	8.9%	10.3%	4.9%	6.7%

The general behaviour is similar for depletion rates of remaining recoverable resources (RRR) as seen in Figure 11. The distribution histogram (Figure 12) shows a skewed structure with only a small number of fields capable of depleting more than 20% of the remaining recoverable resources per year at peak production. Depletion rate differences diminish with increasing field size, indicating a narrowing interval of possible depletion rates. Höök *et al.* (2009a) expanded on this correlation by comparing onshore, offshore, OPEC, and non-OPEC giant oil fields.

High depletion rates are only common in small oil fields, and are increasingly exceptional with increasing field size. As noted earlier, an oil-producing region consists of a sum of individual oil fields, with their individual peak points distributed in time. From the theory described in Section 3.4, it follows that the regional depletion rate must be somewhere between the minimum and maximum depletion rates of its components. Maximum depletion rates can only be reached if all fields peak simultaneously, which is extremely unlikely. According to our analysis of field data, regional depletion rates are likely to be constrained to less than 20% if they are assumed to follow patterns seen in history. Given the dominance of larger fields in total regional production, the regional depletion rates are even lower in reality. Aleklett *et al.* (2010) estimates that the typical regional depletion rates of remaining recoverable resources are of the order of 2–5%, and argue that projections of future global oil production by the IEA (2008) are based upon unrealistic assumptions about depletion rates that are not explicitly discussed. Miller (2011) agrees with the findings of Aleklett *et al.* (2010) and notes the persistent optimism of the IEA projections.

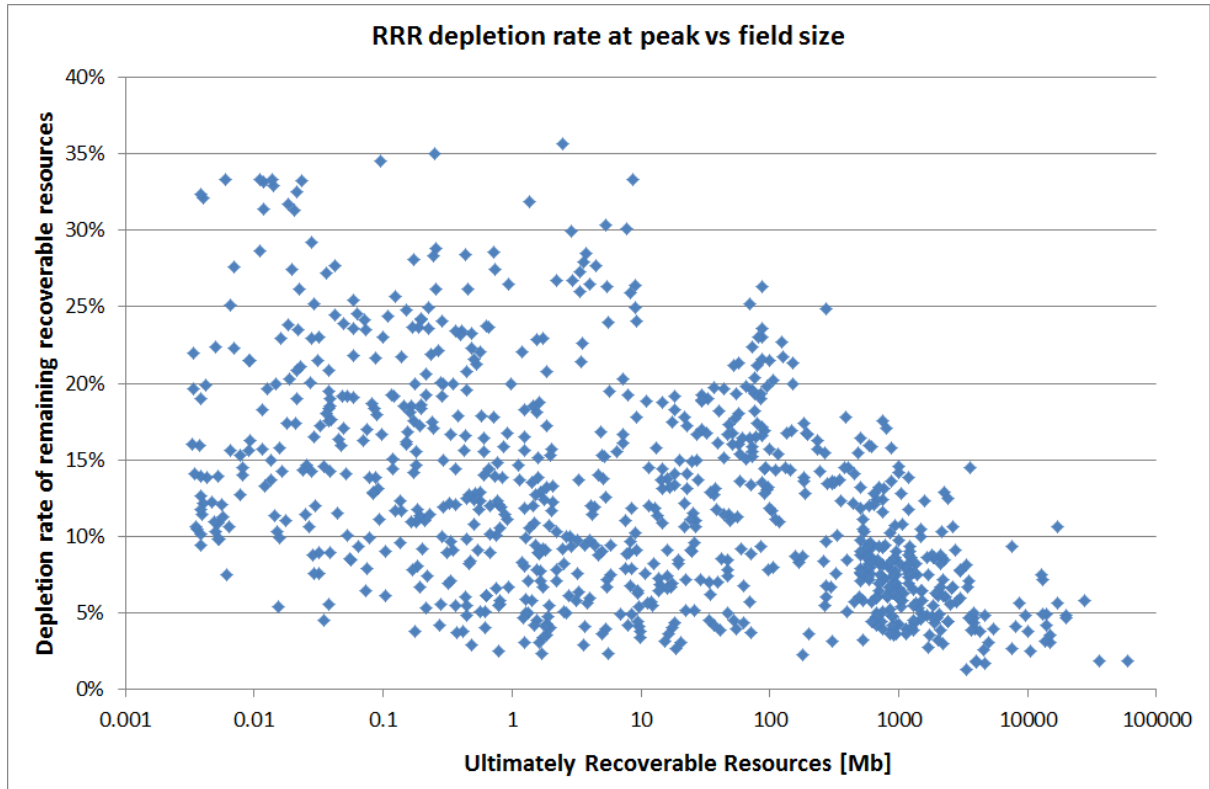


Figure 11. Scatter plot of estimated depletion rates of remaining recoverable resources at onset of decline.

Table 7. Estimated depletion rates of remaining recoverable resources sorted by field size.

Field size [Mb]	Depletion rate at peak production (onset of decline)			
	Median	Mean	Production-weighted mean	Standard deviation
$x < 0.1$	16.4%	17.6%	20.1%	7.1%
$0.1 < x < 1$	14.3%	14.8%	17.3%	7.0%
$1 < x < 10$	9.9%	12.5%	18.4%	7.9%
$10 < x < 100$	13.4%	13.0%	16.3%	5.6%
$100 < x < 1000$	8.7%	10.0%	10.4%	4.6%
$x > 1000$	5.9%	6.4%	6.2%	2.9%
All fields	11.3%	12.5%	7.3%	7.0%

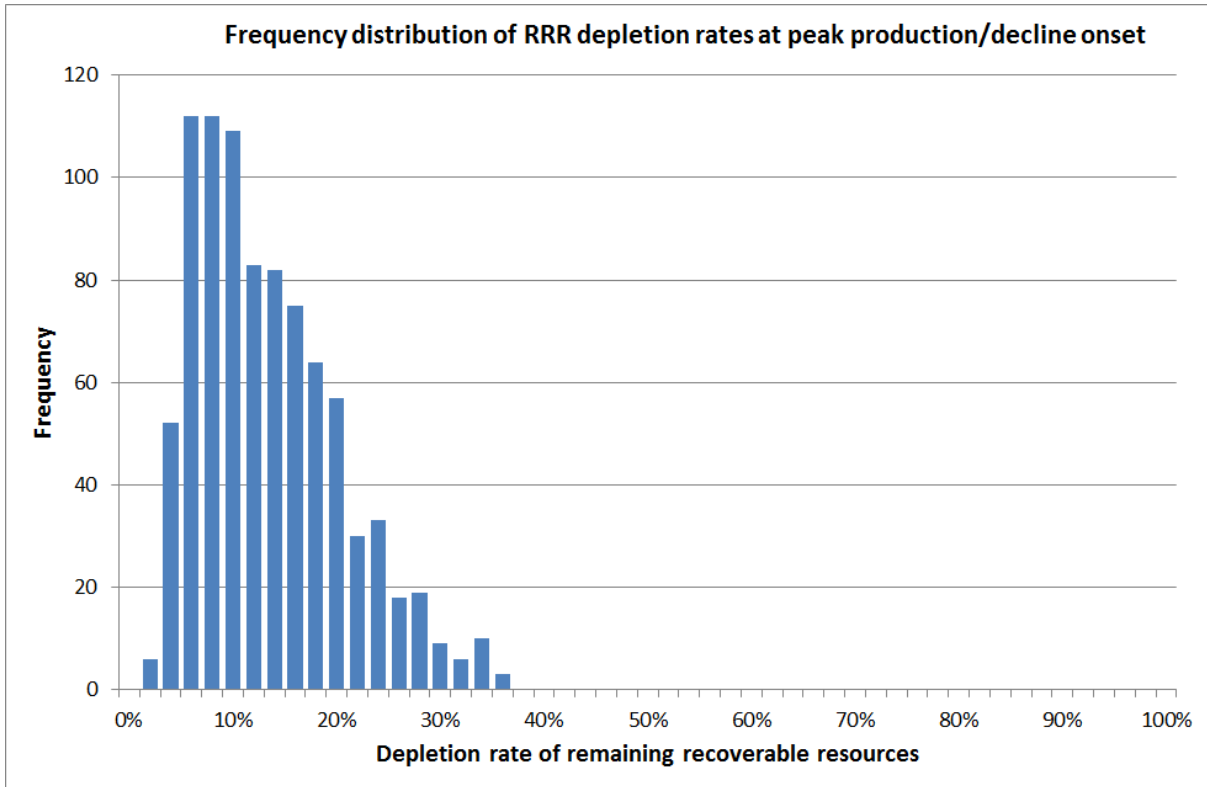


Figure 12. Frequency distribution of RRR depletion rates at peak production/decline onset.

Depletion rates at peak, calculated using both ultimately recoverable resources and remaining recoverable resources, correlate strongly with the subsequent decline rate. The linear correlation coefficient with mean decline rate was determined to be 0.83 for depletion rates of remaining recoverable resources and 0.81 for depletion rates of URR at peak. This observation provides empirical support for the theoretical arguments in Section 3.3.

Depletion rates can be directly calculated from production data and URR estimates during both the build-up and plateau stages in an oil field’s life, even before the field has peaked. In contrast, decline rates can only be estimated after the onset of decline. However, the strong correlation between the concepts makes it possible to use depletion rates to estimate future average decline rates reasonably well. This has already been used to forecast future production profiles for fields that have yet to reach the onset of decline (Höök *et al.*, 2010b). When combined with reliable URR estimates, depletion rate analysis offers a simple tool for making educated estimates of future production decline rates.

5. Concluding discussion

Decline and depletion rates are important to understand and give significant depth to the peak oil debate. However, it is essential to understand that these two concepts are fundamentally different. Decline rates can be measured directly from production data, while depletion rates depend upon estimates of recoverable resources. Changes in recoverability will affect depletion levels and depletion rates, while decline rates are unaffected. Different data sources and resource estimates done at different times are likely to give diverging results.

Comprehensive analysis can be used to identify typical trends and patterns for depletion levels, depletion rates and production decline rates for different categories of fields. Oil field size is a key variable, with generally high values for most parameters in small fields and comparatively low values for larger fields. The data shows clearly that most fields tend to

peak with much less than half of their ultimately recoverable resources produced, typically around 30% (Table 5). Peak production generally appears well before the glass is half empty.

Depletion levels of giant oilfields are a noteworthy detail, since giant fields tend to reach the onset of decline with higher depletion levels than small fields. This could be explained by the way most giant fields are developed, as they usually start production at far lower depletion rates than smaller fields due to requirements related to production equipment, pipelines, etc. As a result, giant fields can maintain production plateau by continually drilling into new parts of the reservoir to supplement declining production from older sections and this can probably lead to comparatively higher depletion levels at peak. However, this could also be an effect of underestimated URR and might possibly change if significant future reserve growth occurs.

The theoretical framework summarised here is well supported by the empirical evidence. The existence of maximum depletion rates prior to the onset of production decline is of particular importance. Furthermore, the strong correlation between depletion rates at peak and subsequent decline rates can be used in supply forecasting and for estimating future decline rates before the plateau phase ends.

Depletion rate analysis has been around for some time, but the underlying methodology has never been clearly presented. Much confusion surrounds the concept of depletion rates, even though it is relatively simple idea once properly understood. Mauger (2012) is a recent example of how terminology is mixed up and how exceptionally low decline rates are used without any solid justification. Another example is how the EIA used a depletion rate model in a flawed way to reach misleading conclusions (Jakobsson *et al.*, 2009). Similarly, the IEA's influential projections of global oil supply are based upon highly unrealistic assumptions about the depletion rates of various categories of resources (UKERC, 2009a; Aleklett *et al.*, 2010; Miller, 2011). Once more realistic assumptions are made; the future supply outlook looks much bleaker.

Due to the large number of geological, technological and economic factors influencing depletion rates, there is no universal maximum depletion rate that is applicable to all fields or all regions. However, the data presented here displays the range of decline and depletion rates that are found in practice and provides a good guide to the depletion rates that may be expected in the future.

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