Applying IFRS in Oil & Gas
IASB – proposed standard

Revised proposal for revenue from contracts with customers
Implications for the oil & gas sector
March 2012
Introduction

In general, we do not expect the latest revenue recognition Exposure Draft (ED) issued by the International Accounting Standards Board (IASB) and the Financial Accounting Standards Board (FASB) (collectively, the Boards), to fundamentally change the revenue recognition for many types of arrangements in the oil and gas sector. However, for some types of arrangements such as take-or-pay arrangements, a thorough analysis of the proposed model will be required to determine the potential impact, as this may not be immediately apparent when reading through the ED. After considering the facts and circumstances of each arrangement in light of the specific requirements of the ED, in combination with the impact of the decisions an entity may make in relation to the practical expedients, entities could potentially determine that the way these contracts are currently accounted for and disclosed may change.

The ED is also unclear as to the effect of the revised proposals on some types of arrangements. This lack of clarity, combined with the fact that the arrangements in this sector can be diverse and complex, would require entities to assess the effect of these new proposals on their own arrangements to enable them to determine whether they will have any impact on the current accounting.

This publication is an oil and gas sector-specific supplement to the recently issued Applying IFRS: Revenue from Contracts with Customers – the revised proposal (January 2012) (general publication). The general publication summarises the revenue recognition model proposed in the ED issued in November 2011, and highlights some issues for entities to consider in evaluating the impact of the ED and discusses some of the expected changes to current IFRS.

This supplement summarises the key aspects of the proposed model and highlights some potentially significant implications of the ED for the oil and gas sector. This includes determining what is in scope and the potential impact on sector-specific contracts and practices. The impact for oilfield services has been considered in a separate publication entitled Revenue from Contracts with Customers: the revised proposal – impact on the Oilfield services sector.

The issues discussed in this supplement are intended to both provoke thought and to assist entities in formulating ongoing feedback to the Boards. The discussions within this supplement represent preliminary thoughts; additional issues may be identified through continued analysis of the ED, or as elements of the ED change based upon further deliberation by the Boards.

What you need to know

- The revised revenue recognition Exposure Draft issued by the IASB and the FASB in November 2011 is not expected to fundamentally change the way revenue is recognised for many oil and gas transactions.
- Also, for some types of arrangements in this sector it is not immediately apparent as to exactly how the proposed model will apply. Therefore a detailed analysis will be required to make such a determination, e.g., take-or-pay arrangements.
- The variety and complexity of arrangements in this sector, combined with the specific requirements of the proposed model including the newly added practical expedients, means entities will need to familiarise themselves with the ED so they are able to properly assess any potential impacts.
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Scope

Definition of revenue and a customer

Revenue is currently defined in IFRS as:

“Income arising in the course of an entity’s ordinary activities.”

This definition has been carried forward unchanged in the ED from current IFRS. The Boards noted in the Basis for Conclusions to the ED that they would not amend the existing definition of revenue as part of this project. Instead, they decided that this was a matter for their joint conceptual framework project.

The proposed revenue recognition guidance in the ED only applies to revenue from contracts with customers. That is, it only deals with a subset of an entity’s potential revenue-generating activities.

The ED defines a customer as:

“... a party that has contracted with an entity to obtain goods or services that are an output of the entity’s ordinary activities.”

Neither current IFRS nor the ED defines “ordinary activities”. The Boards indicated in the Basis for Conclusions to the ED that they were not going to clarify the meaning of “ordinary activities” because that notion was derived from existing revenue definitions, which as noted, were not being revisited as part of this project.

The ED then goes on to explain that for some contracts, while there may be payments between parties in return for what may appear to be goods or services of the entity, the counterparty might not be a customer. Instead, the counterparty may be a collaborator or partner that shares in the risks and benefits of developing a product to be marketed. Contracts with collaborators or partners would not be in the scope of the proposed standard. However, no further guidance is provided to assist an entity in determining whether such collaborative arrangements would be in scope, i.e., when the collaborator or partner would be considered to be a customer.

The Basis for Conclusions explain that while the Boards were asked by some respondents to clarify whether parties to common types of arrangements in their industries would meet the definition of a customer, the Boards decided that it would not be feasible to develop application guidance that would apply uniformly to various industries. This was because the terms and conditions of a specific arrangement may affect whether the parties have a supplier-customer relationship or some other relationship, e.g., collaborator or partner. Instead, the parties to the arrangement would have to consider all facts and circumstances to determine if they are in scope of the revenue recognition ED or not.

How we see it

There are many complex contracts in the oil and gas sector and some diversity currently exists in how these are accounted for. The decision not to revisit the definitions of “revenue” or “ordinary activities”, while proposing a model that only deals with a subset of an entity’s total revenue generating activities, does not assist in resolving the uncertainty as to what constitutes an entity’s ordinary activities and, hence, represents revenue from contracts with customers.

Determining who the customer is, and therefore what contracts are in scope, will require an assessment of the individual facts and circumstances. The absence of specific guidance on what are considered an entity’s ordinary activities and therefore who may be customers of an entity, may lead to diverse interpretations.

Generally, if a contract was not previously considered to be a contract with a customer, we do not believe this ED will change such a conclusion. However, in some cases, what constitutes a customer contract may not be clear. Therefore, some contracts (e.g., production sharing contracts) may need to be evaluated to determine if they do represent contracts with customers.

It is our understanding that should a contract or arrangement not fall within the scope of this ED, it does not necessarily preclude the potential inflows from such contracts from being described as part of total revenue.

2 IASB’s Conceptual Framework for Financial Reporting paragraph 4.29
The current accounting for operating leases and service contracts is often similar. Determining that a service arrangement contains an operating lease generally does not result in significantly different accounting for the arrangement under current accounting standards. Consequently, it is possible that to date not all embedded leases have been identified, extracted and/or accounted for separately.

However, under the proposed leasing model, the accounting for a lease by the lessor could be significantly different from the accounting for a service arrangement. Therefore, this assessment may have significantly different accounting implications where service contracts are considered to contain embedded leases. This will increase the importance of analysing contracts to determine that the revenue recognition requirements are appropriately applied to elements within its scope.

Other scope exemptions

The ED states that if a contract is partially within the scope of the proposed revenue recognition standard and partially within the scope of another standard, entities would first apply the separation and measurement requirements of the other standard (e.g., accounting for an embedded lease or an embedded derivative). Once the contract elements were separated, the proposed revenue recognition guidance would be applied only to the revenue elements.

Risk services contracts

In a risk services contract (also called a risked services agreement or an at-risk services contract), an entity (contractor) agrees to explore for, develop, and produce minerals on behalf of a host government, but the contractor is at risk for the amount spent on exploration and development costs.

If production commences, the entity will receive a fee representing its costs plus a profit (the fee is typically capped at a certain price per barrel produced). However, if no minerals are found in commercial quantities, no fee is paid.

This type of contract is different from a pure services contract, which is considered to be a management contract that gives rise to revenue from rendering services and not income from the production of minerals.

Current practice

Currently, there is no specific guidance within IFRS governing the accounting for PSCs or risk services contracts and consequently, accounting approaches have evolved over time. These contracts are generally considered to be more akin to working interest relationships than pure services contracts. This is because the oil and gas company is assuming risks associated with performing oil and gas producing activities and is either receiving a fee or a share (and often a greater share) of future production as specified in the contract.

Under current IFRS, revenue is recognised only once the oil and gas company receives its share of the oil or gas under the PSC (i.e., cost and profit oil) and sells those volumes to third party customers, rather than being recognised as a fee for services rendered to the NOC.

Potential impact of the new proposals

In determining whether the contract between a NOC and the oil and gas company is within the scope of the ED, an entity must look to the definition of a customer and what constitutes “ordinary activities”, as discussed above. If an entity was to decide that the NOC was a customer, then the contractual arrangement would be in the scope of this proposed standard and an analysis of the impact of the proposed requirements would be necessary. However, we expect that for most PSCs, the relationship between the oil and gas company and the NOC would probably not represent a customer relationship relating to the provision of services.
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How we see it

As the Boards appear to be relying on current definitions of revenue and what constitutes “ordinary activities”, we do not expect there to be a significant change in whether a PSC or risk services contract results in a customer relationship.

Under the proposed requirements, we believe the relationship between the oil and gas company and the NOC would probably not represent a customer relationship relating to the provision of services. Instead, it is more likely to be considered a contract between collaborators or partners. Therefore, such contracts would be outside the scope of this ED.

However, the terms and conditions of contracts with governments/NOCs continue to evolve, particularly given the percentage of the world’s oil and gas reserves that are owned by governments. The facts and circumstances of all arrangements should be carefully assessed to determine whether the relationship between the two parties changes and potentially becomes a supplier-customer relationship and, hence, falls within scope.

An entity would also need to analyse the impact of such an analysis on its ability to be able to book reserves, as pure services contracts generally do not result in an entity being able to book reserves.

Production imbalances

Production imbalances often arise on oil and gas properties for which two or more owners have the right to take production in kind. Each owner is entitled to their working interest percentage in the property’s total production. However, at any given time, the amount of oil or gas actually sold by each owner may differ from its working interest percentage. The discrepancies in the amounts sold and the amounts that the interest owners are entitled to are referred to as production imbalances.

Current practice

IFRS does not currently address the accounting for these imbalances directly. Oil and gas revenue recognition follows variations of one of two currently accepted methods:

a) Sales method
Revenue is recognised based on the actual amounts sold, which may differ from volumes the oil and gas entity is entitled to. No receivables or payables are recorded for any imbalance, but proved reserves are adjusted.

b) Entitlements method
Net revenue reflects each owner’s contractual share of production regardless of who actually made the sale and invoiced the volumes. A receivable or payable is recorded based on the imbalance. Generally, the imbalance in a particular period will be “made-up” so that at the end of the field life each party with a working interest will have sold an amount materially consistent with the volumes to which it is entitled.

To account for the imbalance between actual sales and entitlements, one of the following approaches is used:

i) Adjust revenue: The excess of product sold during the period over the participant’s ownership share of production from the property is recognised by the overlift party as a liability and not as revenue. Conversely, the underlift party recognises an underlift asset and reports the corresponding revenue. It is our understanding that this method is quite rare among IFRS preparers.

Or

ii) Adjust cost of sales: Cost of sales is adjusted to take account of an asset or liability that reflects the lifting imbalance while revenue is shown at the actual invoiced amount.

Potential impact of the new proposals

It is currently unclear whether transactions to settle imbalances between working interest owners would be revenue transactions and, hence, in the scope of this proposed standard. This is because the proposed standard only applies to contracts with customers. As noted, the proposed standard states that where the counterparty is a collaborator or partner, the contract would not be within scope. However, no further guidance is provided to determine when another working interest party would be a customer or a collaborator/partner.

Illustration 1 – Accounting for imbalances

Oil and gas Company A and Oil and Gas Company B each hold a 50% working interest in Field C.

Field C produces 100,000 barrels of oil in the current month. Company A sells 60,000 barrels of oil at $75/barrel to Refining Company D. So actual sales equate to 60,000 barrels and there is an imbalance of 10,000 barrels (60,000 barrels – [100,000 barrels x 50%]).
The Basis of Conclusions to the ED provides examples of arrangements that should be analysed to determine if a supplier-customer relationship exists or if it is some other type of relationship. One of the specific examples included is arrangements between partners in the oil and gas sector relating to imbalances between proportionate entitlements and sales volumes.

These are only mentioned as a type of arrangement to be considered — no conclusions are provided. Instead, the ED simply states that all relevant facts and circumstances need to be considered in assessing whether the counterparty meets the definition of a customer. Therefore, the assessment of such arrangements could be open to interpretation and divergence in practice may continue if further guidance is not provided.

a) Sales method
The sale of the actual product by the oil and gas company to a third party represents a contract with a customer. Therefore, it would be in scope of the ED (regardless of whether the seller is entitled to the volumes).

b) Entitlements method
The entitlements method could effectively be considered to comprise two components:

- The actual sale of product to a third party, which would be accounted for the same as the sales method.

And

- Accounting for the imbalance between the working interest owners, which probably would not qualify as a contract with a customer, as the counterparty (i.e., the working interest owner) may not be considered to be a customer. If this is the case, accounting for the imbalance would generally fall outside the scope of the ED and other IFRSs would need to be considered.

Therefore, we consider that the current method of adjusting cost of sales will continue to be available.

Where adjustments for the imbalance are made against sales/revenue, it is unclear what the impact will be of applying the proposed standard. Where positive adjustments, i.e., underlifts, are currently made against revenue, our understanding is that, while these are unlikely to be considered within the scope of the ED, this would not necessarily prohibit the adjustment from being described as part of total revenue from ordinary activities. Consequently, without specific guidance to the contrary, it is likely that this approach will continue to be available.

Potentially greater difficulties may arise for an overlift party who accounts for this situation by reducing revenue by the amount of the imbalance by effectively recognising a debit to total revenue and then recognising a liability. If such an adjustment has to be presented separately from “revenue from contracts with customers”, from a presentation perspective, it would result in a net debit balance in the revenue section. It is unclear whether this presentation would be accepted or whether such an adjustment would have to be made elsewhere in profit or loss.

How we see it

We believe the sales method would be within the scope of the ED and therefore current practice is likely to remain unchanged.

In relation to the entitlements method, we believe the actual sale of product to the end customer would fall within scope and would continue to be recognised as revenue when control transfers to the customer. The accounting for the imbalance would fall outside of scope unless the arrangement represents a contract with a customer. Therefore, other IFRSs would need to be applied.

Since both methods have been accepted to date and no further clarity is provided, current practices are likely to continue to be accepted under these proposed revenue recognition requirements.
Production payments

Entities sometimes seek funding for exploration and development activities and repay the lender with a production payment royalty. There are basically two types of production payments. One type is repayable in cash from the sales proceeds of a specified share of future production of a producing property, until the amount advanced plus interest at a specified or determinable rate is paid in full. The other type is payable in volumes (volumetric production payments). In these arrangements the entity’s obligation is to deliver, free and clear of all expenses associated with operation of the property, a specified quantity of oil or gas to the purchaser out of a specified share of future production.

Current practice

The first type of production payment is accounted for as borrowings under IAS 39 Financial Instruments: Recognition and Measurement. For the second type of production payment, given the nature of the obligation, the entity receiving the funds accounts for these as unearned revenue, which will be recognised as revenue as the oil or gas is delivered.

Potential impact of the new proposals

The accounting for arrangements where repayments are made in cash is likely to be unaffected by this ED. Therefore, they will continue to be accounted for as financing transactions under IAS 39.

Whether volumetric production payments fall within the scope of this ED will depend upon whether or not the counterparty is considered to be a customer. If the counterparty is not considered to be a customer, such transactions would be outside of scope and current accounting may be able to continue. However, should the counterparty be considered a customer, then the following would be likely to occur:

- A contract liability related to the unsatisfied performance obligation to deliver oil or gas in the future would be recognised when the consideration is received, rather than unearned revenue. This may be difficult to reliably measure where future production levels are highly uncertain
- Revenue would be recognised as the performance obligation is satisfied i.e., as the production payments are made
- The time value of money would have to be incorporated (if there is a significant financing component), which may result in increased revenue ultimately being recognised as well as interest expense

For additional guidance on the accounting for the time value of money, see our general publication.

How we see it

Similar to other transactions, determining whether the proposed revenue recognition model will impact current accounting will depend on whether or not the counterparty is considered to be a customer. If it is considered to be a customer, the complexity in measuring and recognising revenue may increase and could impact the quantum and type of items recognised in profit or loss, including revenue and interest expense. It could also impact the types of disclosures required.

Purchases and sales of inventory with the same counterparty

Oil and gas companies frequently enter into what are called ‘buy/sell arrangements’ to obtain product at a specified location or sell a refined product to a particular market without incurring transportation costs.

Current practice

Currently, IAS 18 states that when goods or services are exchanged or swapped for goods or services which are of a similar nature and value, the exchange is not regarded as a transaction that generates revenue.

Determining whether such exchanges or swaps are within scope requires a degree of judgement, in particular:

- When the inventories exchanged are not identical (e.g., swaps of slightly different oil products, possibly with an adjustment for the difference in quality)
- There is some past practice of settling net in cash

3 The potential implications arising from IFRS 9 Financial Instruments have not been considered in this supplement.
Potential impact of the new proposals

The scope of the ED specifically excludes non-monetary exchanges between entities in the same line of business to facilitate sales to customers, or to potential customers, other than the parties to the exchange (e.g., an exchange of oil to fulfill demand on a timely basis in a specified location).

While such parties could technically meet the definition of a customer, the Boards decided to exclude these exchanges from the scope of the ED. They considered that recognizing these as revenue-generating transactions would gross up revenues and expenses and make it difficult for financial statements users to assess an entity's performance and gross margins. Also, in some situations, the counterparty to such an arrangement was believed to be acting as a supplier rather than a customer.

In addition, buy/sell arrangements that are considered derivatives would also be scoped out of the revenue recognition requirements and would instead continue to be accounted for under IAS 39.

How we see it

It is our understanding that the Boards did not expect the treatment of inventory exchanges to change as a result of the proposed new model. However, in our view, this has not been made clear in the wording of the ED.

The change in the wording from goods or services that are "similar in nature and value", to exchanges between entities in the "same line of business", means that it is unclear whether some transactions that are currently treated as exchanges of dissimilar goods and hence, are revenue generating, may now not be considered to be revenue generating because the entities are in the same line of business.

Also, while the scoping section of the ED makes it clear that inventory exchanges do not result in revenue generation, it does not provide guidance on how the transactions between the two parties should be accounted for and no other specific guidance exists within IFRS (as compared to US GAAP). Given the lack of clarity, the current divergence in accounting may continue.

However, for the party who is receiving or borrowing the product, when they sell that product to an external customer, such a transaction would be in the scope of the proposed standard.

Royalty payments

Oil and gas entities frequently enter into royalty arrangements with owners of mineral rights. These are often payable upon the extraction and/or sale of the oil or gas. The royalty payments may be based on a specified rate per volume of product or the entity may be obliged to dispose of all of the relevant production and pay a specified proportion of the aggregate proceeds of sale, often after deduction of certain lifting (e.g., conveying and treating) costs.

In other arrangements, the royalty holder may have a more direct interest in the underlying production and may make lifting and sale arrangements independently. This is can be seen in some royalty agreements in the US.

The issue, from a revenue recognition perspective, would be whether revenue should be presented gross or net of these royalty payments.

Current practice

The accounting treatment for government and other royalties payable is diverse. Sometimes, all invoiced quantities are included in revenue, and royalty payments are charged either as a cost of sales or as a tax. In other cases, they are excluded from both the value of reported revenue and cost of sales/taxes on the basis that the entity has no legal right to the royalty product.

Potential impact of the new proposals

While the ED and associated guidance do discuss some of the issues affecting gross versus net presentation, they do not directly address the treatment of royalty payments.

However, the ED requires revenue to be recognized at the "transaction price", and the transaction price is defined as "the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, excluding amounts collected on behalf of third parties (for example, sales taxes)". Other than this, there is no additional guidance provided.

Consequently, the ED does not clarify whether a royalty is a cost of production/tax and, therefore, revenue should be recognized gross, or whether a royalty is considered an amount collected on behalf of another party (which is usually the government, but could be another type of party) and hence, would be excluded from revenue.

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4 ASC 845 Nonmonetary Transactions.
5 ED/2011/6 Revenue from Contracts with Customers Appendix A.
It is unclear from the revenue recognition ED whether revenue should be recognised gross or net of royalty payments as the proposals do not specifically address whether royalties are considered to be “amounts collected on behalf of a third party”. Without further guidance, divergence is likely to continue in that similar arrangements may be accounted for differently.

In our view, where royalties are payable in kind, revenue should be presented net of these amounts as the entity would never have received any inflow of economic benefits in relation to such volumes. However, where an entity is required to sell the product in the market and remit the net proceeds (after deduction of certain costs incurred) to the royalty holder, the entity may be considered to be exposed to the risks and rewards of ownership to such an extent that it is appropriate to present revenue on a gross basis and include the royalty payment within cost of sales.

Current practice

Under current IFRS, revenue is recognised, as follows:

a) Volumes taken: revenue is recognised when the volumes of the product concerned, e.g., gas, are actually delivered and they are measured at the amount invoiced to the customer based upon applicable price at that time, e.g., market price or fixed price (as specified in the contract)

b) Volumes not taken but paid for:
   i) No entitlement to make-up volumes: revenue is recognised when the payment is due from the customer, which is often at the end of the stated take-or-pay period, e.g., every 12 months
   ii) Customer is entitled to make-up volumes: the amount paid by the customer is recognised as deferred/uneearned revenue, and is recognised as revenue either when the payment is applied to future deliveries or the right to apply the payment to such deliveries expires unused. Interest is generally not accrued on such amounts

Potential impact of the new proposals

Given the length and complexity of these long-term take-or-pay arrangements, in conjunction with the addition of some new practical expedients to the current ED, it may be difficult to determine exactly what impact the requirements of the proposed new model will have on the financial statements.

Given this, below, we summarise the key aspects of the model, including the new practical expedients that will be of most relevance in determining the impact of the ED on these types of arrangements. We then consider how these may be interpreted and applied specifically to take-or-pay arrangements.

Step 1: Identifying the contract

The first step in the proposed model is to identify the contract. The ED states that a contract is an agreement that creates enforceable rights and obligations, and that a contract does not exist (for the purposes of the standard) if each party to the contract has the right to independently terminate, i.e., without approval from the other party/parties, a contract under which none of the parties have performed its obligations, without compensating the other party/parties.

How we see it

Take-or-pay arrangements

A take-or-pay contract is a supply agreement between a customer and a supplier in which the price is set for a specified minimum quantity of a particular good or service and the price is payable irrespective of whether the good or service is taken up by the customer.

Take-or-pay arrangements are quite common in the oil and gas sector and may involve the supply of gas or pipeline capacity. These arrangements can be long-term in nature and can contain terms and conditions with varying degrees of complexity, e.g., fixed or stepped volumes; simple fixed pricing, stepped pricing or variable pricing.

In addition, for payments made in relation to volumes not taken, i.e., where the customer does not take the minimum quantities specified, the terms may vary. Some take-or-pay arrangements include a clause that allows the customer to “make-up” the volumes not taken at a later date. The ability to make-up the unused volumes means that consideration has been received in advance by the producer for product that has not yet been delivered. Alternatively, the contract may contain a “use it or lose it” clause, where the customer cannot make-up the unused volumes in the future. In such a situation, this payment would be more akin to a type of penalty payment.
Oil and gas Company A enters into a 3-year take-or-pay contract for a minimum of 1000 MMbtu of gas per year.

In relation to take-or-pay arrangements, the “contract” would generally be the minimum amount specified, as this is generally the only enforceable part of the arrangement. There may also be options for the entity to acquire additional volumes over and above the minimum. However, any amounts greater than the minimum would likely be considered a separate contract that needs to be accounted for at the time the customer exercises this option, as this is when it would become enforceable.

Nevertheless, there may be instances when such an option provides a material right to the customer that it would not receive without entering into that contract. The ED notes that such a right would be material only if it results in a discount that the customer would not otherwise receive (e.g., a discount that is incremental to the range of discounts typically given for those goods or services to that class of customer in that geographical area or market). If the option provides a material right to the customer, the option would be accounted for as a separate performance obligation in the original contract. The inclusion of the option as a separate performance obligation will impact the revenue recognition profile of the original contract. Further details on identifying the contract and accounting for these options, can be found in Sections 2 and 3.7 of our general publication.

Step 2: Identifying the performance obligations

The next step is to identify all promised goods or services in the contract and then determine whether to account for each good or service as a separate performance obligation. That is, the entity would need to identify the distinct goods and services representing individual units of account. Section 3 of our general publication explores in further detail the requirements for identifying separate performance obligations, and whether they meet the concept of being distinct.

In applying this requirement, one question that arises is how an entity should identify the performance obligations and, specifically, what level of granularity is needed.

While the proposed standard requires distinct goods and services to be identified as the first step in identifying performance obligations, it then outlines two possible ways in which distinct goods and services should or could be bundled.

The first approach looks at the interrelationship between the goods and services provided. That is, to what extent are the goods and services provided together with an overall significant integration service and significant modification and customisation to fulfil the contract. Treatment of these as a bundle is a requirement of the ED and not an election. This type of bundling is discussed in more detail in Section 3.2 of our general publication.

The second approach is a practical expedient that has been added to this ED, which is intended to simplify the application of the model. This practical expedient allows an entity to account for multiple distinct goods and services as one performance obligation when the underlying goods and services have the same pattern of transfer. We believe this could occur either when there is simultaneous transfer (i.e., at the same point in time or over the same period of time) or consecutive transfer (where the pattern of transfer is similar, e.g., units produced). The practical expedient appears to be a choice (on a contract-by-contract basis) provided by the ED rather than a requirement.

Illustration 2

Oil and gas Company A enters into a 3-year take-or-pay contract for a minimum of 1000 MMbtu of gas per year.

In considering the requirements of identifying the performance obligations of the contract, the following outcomes may be selected by an entity:

- 3000 separate performance obligations for the delivery of 1 MMbtu of gas over three years. At its lowest level each MMbtu of gas is considered to be a distinct performance obligation.
- One single performance obligation for the delivery of 3000 MMbtu of gas. Making use of the practical expedient, the entity may consider the entire contract to be one distinct performance obligation.
- Three performance obligations for the delivery of 1000 MMbtu of gas per year. This is an example of a variation that could potentially be created by applying the practical expedient to discrete time periods.
Given the criteria specified for determining whether a good or service is distinct, we believe it is likely that each MMbtu of gas would be considered a separate performance obligation. Therefore an entity would initially identify the performance obligations under each contract at this level of detail. However, by virtue of the practical expedient provided, we believe that as these performance obligations are transferred consecutively with a similar pattern, i.e., per MMbtu, the multiple performance obligations could be combined into one single performance obligation. This could potentially be applicable to any number of discrete time periods, e.g., 1000 MMbtu per annum or to the entire take-or-pay contract, i.e., the 3000 MMbtu of gas, being combined into one single performance obligation.

Later in this document we explore the impact a decision to use the practical expedient can have on the application of the other requirements of the proposed ED, including the disclosure requirements.

Step 3: Determining the transaction price

The third step is to determine the transaction price of the contract. The ED defines the transaction price as “the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, excluding amounts collected on behalf of third parties (e.g., sales taxes)”\(^6\). In many cases, the transaction price is readily determined because the entity receives payment at or near the same time as it transfers the promised good or service and the price is fixed for the minimum committed purchases. However, determining the transaction price may be more challenging when it is variable in amount, when payment is received at a time different from when the entity provides goods or services, or when payment is in a form other than cash. Consideration paid or payable by the vendor to the customer may also affect the determination of the transaction price.

Specifically in relation variable transaction prices, the ED provides examples of factors that can cause the transaction price of a contract to vary in amount and timing. These factors include discounts, rebates, refunds, credits, incentives, bonuses, penalties, contingencies or concession. Another way in which the transaction price can vary, considered in illustrative example 13 to the ED, is where the price for each unit is variable, e.g., it is based upon or linked to a market price (or some other variable price).

Where the transaction price is variable, the ED requires an entity to estimate the transaction price using either the “expected value” (probability weighted) approach or the “most likely amount” approach, whichever better predicts the ultimate consideration to which the entity will be entitled. Further information on these approaches is set out in Section 4 of our general publication.

Step 4: Allocating the transaction price

The next step is to allocate the transaction price to the performance obligations (where there is more than one performance obligation). Such an allocation would ordinarily be in proportion to the relative standalone selling price of each performance obligation (except in specific circumstances where the residual methodology is permitted). Under the ED, the standalone selling price is the price at which an entity would sell a good or service on a standalone basis at contract inception.

The ED is not clear on how to determine the standalone selling price at contract inception where there is only one type of good, e.g., a MMbtu of gas, and the contract requires selling multiple units of that good in succession as in a take-or-pay contract. Using our example, is the price of a MMbtu of gas to be sold and delivered today different to a MMbtu of gas you expect to sell and deliver in three years’ time? Later in this document we explore the potential impact of this question.

Section 5 of our general publication provides more details about how an entity determines a standalone selling price and how these are used to allocate the transaction price.

Exceptions to the relative standalone selling price

Two exceptions to the relative selling price method of allocating the transaction price are proposed in the ED. The first relates to the allocation of variable or contingent consideration, and the second relates to the allocation of a discount (see Section 5.4 of our general publication for details on the second exception).

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\(^6\) ED/2011/6 – Revenue from Contracts with Customers – Appendix A
In relation to the first exception, the ED states that variable or contingent consideration can be allocated entirely to a distinct good or service if both of the following criteria are met:

- The variable or contingent payment terms for the distinct good relate specifically to the entity's efforts to transfer that good
- The amount allocated depicts the amount of consideration to which the entity expects to be entitled in exchange for transferring that distinct good

So it does not have to be allocated to all distinct goods or services or to other performance obligations that may exist in the contract, provided these criteria are met.

Step 5: Satisfaction of performance obligations – recognition of revenue

An entity would only recognise revenue when it satisfies an identified performance obligation by transferring a promised good or service to a customer. A good or service is considered to be transferred when the customer obtains control. For the former, revenue would be recognised at the point in time that control transfers to the customer. For the latter, the associated revenue is recognised over the period the performance obligation is satisfied.

For those performance obligations satisfied over time, an entity must assess if control has passed. The ED indicates that performance obligations are either satisfied at a point in time or they are satisfied over time. For the former, revenue would be recognised at the point in time that control transfers to the customer. For the latter, the associated revenue is recognised over the period the performance obligation is satisfied.

For those performance obligations satisfied over time, an entity will need to decide how it will measure its progress towards satisfaction of that performance obligation. Two appropriate methods of measuring progress provided in the ED include output methods and input methods. Output methods use the value to the customer of the goods or services transferred to date as the basis for measurement, e.g., resources consumed, labour hours expended, or costs incurred relative to the total expected inputs.

In addition, in relation to output methods, the ED states that if an entity has a right to invoice a customer in an amount that corresponds directly with value to the customer of the entity's performance completed to date, the entity would recognise revenue in the amount to which the entity has a right to invoice.

For take-or-pay arrangements, where each MMbtu of gas is treated as a separate performance obligation, we believe these would be considered to be satisfied at a point in time.

However, where an entity elects to apply the practical expedient and treat all MMbtu of gas to be delivered as one single performance obligation, we believe these would satisfy the criteria to be considered as being satisfied over time. Given the nature of these arrangements, the most appropriate measure of progress towards complete satisfaction of this performance obligation satisfied over time, would most likely be the output method. If the entity is then able to demonstrate that it has the right to invoice the customer directly for the amount of product taken, measured at the applicable price at the date of delivery, and this amount directly corresponds to the value to the customer of the entity’s performance to date, revenue could be recognised based upon these invoiced amounts.

Section 6 of our general publication explores in more detail the requirements relating to the satisfaction of performance obligations, including factors to consider when determining when control has been transferred and how an entity measures its progress towards complete satisfaction of a performance obligation.

Constraining the cumulative amount of revenue recognised

Although an entity would estimate the total transaction price (without any particular constraint on the estimate), the amount of revenue the entity could recognise may be constrained. The ED states that the cumulative amount of revenue an entity would be able to recognise for a satisfied or partially satisfied performance obligation is limited to the amount to which the entity is reasonably assured to be entitled (refer to Section 6.3 of our general publication for further guidance on determining when the amount to which an entity expects to be entitled is reasonably assured).

Application of the proposed model to take-or-pay arrangements

The following examples illustrate the potential impact these new proposals may have on take-or-pay arrangements. We have selected two primary types of arrangements – one with a fixed price and the other with a variable price. For the fixed price contract, we have two scenarios – one where the price is fixed for the life of the contract and the other where the fixed price steps up each year of the contract.

For the purposes of these examples, in both situations (fixed and variable prices), the “contract” to be accounted for is the minimum volumes over three years – so 3000 MMbtu in total and there are no material options for additional gas.
Fixed price and stepped fixed price contracts

<table>
<thead>
<tr>
<th>Terms</th>
<th>Fixed price (life of contract)</th>
<th>Stepped fixed price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length of contract</td>
<td>3 years</td>
<td>3 years</td>
</tr>
<tr>
<td>Minimum volumes</td>
<td>1000 MMbtu per year</td>
<td>1000 MMbtu per year</td>
</tr>
<tr>
<td>Price per MMbtu</td>
<td>CU 1,000</td>
<td>Year 1 – CU 500</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Year 2 – CU 1,000</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Year 3 – CU 1,500</td>
</tr>
</tbody>
</table>

**Step 2: Identify the performance obligations**

As noted above, there are a number of potential ways to identify the performance obligations under these contracts – we will specifically consider:

- 3000 separate performance obligations for 1 MMbtu of gas each
- The entity applies the practical expedient and combines these into one single performance obligation to deliver 3000 MMbtu of gas over 3 years

And we will explore how the requirements of the ED would apply to each.

**Step 3: Determine the transaction price**

As a fixed price contract, this step would be relatively straightforward:

<table>
<thead>
<tr>
<th>Contract type</th>
<th>Calculation</th>
<th>Total transaction price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed price (life of contract)</td>
<td>3yrs x 1000 MMbtu x CU 1,000</td>
<td>CU 3,000,000</td>
</tr>
<tr>
<td>Stepped fixed price</td>
<td>Year 1 = 1000 MMbtu x CU 500 = CU 1,000,000</td>
<td>CU 3,000,000</td>
</tr>
<tr>
<td></td>
<td>Year 2 = 1000 MMbtu x CU 1,000 = CU 500,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Year 3 = 1000 MMbtu x CU 1,500 = CU 1,500,000</td>
<td></td>
</tr>
</tbody>
</table>

**Steps 4 and 5: Allocate the transaction price to the performance obligations and recognise revenue**

The outcome of these steps will depend upon how the performance obligations are determined, i.e., either 3000 separate performance obligations for 1 MMbtu each or one single performance obligation.

**a) 3000 separate performance obligations**

If this approach is taken, an entity would need to:

- Determine the standalone selling price of each performance obligation
- Allocate the transaction price based upon the relative standalone selling prices

As noted, it is not clear whether the standalone selling price of an identical unit, i.e., a MMbtu of gas to be sold repeatedly over a period of time, is determined at contract inception by looking at the price of a unit sold and delivered at inception or whether the entity would have to consider the standalone selling prices for a MMbtu of gas to be sold and delivered in the future, i.e., the entity should consider future pricing.

The former will result in an identical standalone selling price for each performance obligation, i.e., each MMbtu of gas. The latter may result in a different standalone selling price for each MMbtu of gas or groups of MMbtu. This would impact the allocation of the transaction price, increase the complexity of applying the model and would ultimately impact the pattern of revenue recognition.

To illustrate, assume the following prices for future delivery:

- To deliver a MMbtu of gas throughout year 1, the price would be CU 500**
- To deliver a MMbtu of gas throughout year 2, the price would be CU 1,000**
- To deliver a MMbtu of gas throughout year 3, the price would be CU 1,500***

** We have assumed that the views around the future standalone selling prices of gas have been built into the pricing of the contract – so these future prices happen to be the same as the stepped prices in the contract. However, this may not always be the case.

** Constant standalone price**

Here we have assumed that as the contract involves selling identical products, i.e., gas, each MMbtu of gas would have the same standalone selling price at contract inception, regardless of when the as was to be delivered. This would mean that each MMbtu of gas would be allocated the same proportion of the transaction price. So, an entity would allocate the total transaction price as follows:

<table>
<thead>
<tr>
<th>Calculation</th>
<th>Price per tonne</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed price contract</td>
<td>CU 3,000,000/3000 MMbtu</td>
</tr>
<tr>
<td>Stepped price contract</td>
<td>CU 3,000,000/3000 MMbtu</td>
</tr>
</tbody>
</table>

**CU 1,000/MMbtu**
Future standalone selling prices

As noted above, in this scenario we have assumed that the standalone selling price of a MMbtu of gas to be sold and delivered today is different to the standalone selling price of a MMbtu of gas to be sold and delivered in the future. This means that the gas to be sold and delivered throughout year 1 would attract a different proportion of the transaction price to the gas to be sold and delivered throughout years 2 and 3. Given this gas sold throughout each of the various years would attract the following percentages of the total transaction price:

<table>
<thead>
<tr>
<th>Year</th>
<th>Calculation</th>
<th>Total transaction price</th>
<th>Relative % of total (rounded)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CU 500 x 1000</td>
<td>CU 500,000</td>
<td>16.67%</td>
</tr>
<tr>
<td>2</td>
<td>CU 1,000 x 1000</td>
<td>CU 1,000,000</td>
<td>33.33%</td>
</tr>
<tr>
<td>3</td>
<td>CU 1,500 x 1000</td>
<td>CU 1,500,000</td>
<td>50.00%</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>CU 3,000,000</strong></td>
<td></td>
</tr>
</tbody>
</table>

In applying all of the information calculated above, the revenue recognition profile may be as follows:

**Fixed price contract**

<table>
<thead>
<tr>
<th>Year</th>
<th>Current IAS 18</th>
<th>Constant standalone selling price</th>
<th>ED</th>
<th>Future standalone selling price</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Calculation</strong></td>
<td><strong>Revenue</strong></td>
<td></td>
<td><strong>Calculation</strong></td>
</tr>
<tr>
<td>1</td>
<td>CU 1,000,000</td>
<td>1000 MMbtu x CU 1000</td>
<td>CU 1,000,000</td>
<td>CU 3,000,000 x 16.67%</td>
</tr>
<tr>
<td>2</td>
<td>CU 1,000,000</td>
<td>1000 MMbtu x CU 1000</td>
<td>CU 1,000,000</td>
<td>CU 3,000,000 x 33.33%</td>
</tr>
<tr>
<td>3</td>
<td>CU 1,000,000</td>
<td>1000 MMbtu x CU 1000</td>
<td>CU 1,000,000</td>
<td>CU 3,000,000 x 50.00%</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>CU 3,000,000</strong></td>
<td></td>
<td><strong>CU 3,000,000</strong></td>
</tr>
</tbody>
</table>

In this scenario, if we assume a constant standalone selling price, the revenue recognition profile is the same as that currently achieved under IAS 18. However, if we assume a future standalone selling price, the revenue recognition profile changes.

**Stepped price contract**

<table>
<thead>
<tr>
<th>Year</th>
<th>Current IAS 18</th>
<th>Constant standalone selling price</th>
<th>ED</th>
<th>Future standalone selling price</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Calculation</strong></td>
<td><strong>Revenue</strong></td>
<td></td>
<td><strong>Calculation</strong></td>
</tr>
<tr>
<td>1</td>
<td>CU 500,000</td>
<td>1000 MMbtu x CU 1,000</td>
<td>CU 1,000,000</td>
<td>CU 3,000,000 x 16.67%</td>
</tr>
<tr>
<td>2</td>
<td>CU 1,000,000</td>
<td>1000 MMbtu x CU 1,000</td>
<td>CU 1,000,000</td>
<td>CU 3,000,000 x 33.33%</td>
</tr>
<tr>
<td>3</td>
<td>CU 1,500,000</td>
<td>1000 MMbtu x CU 1,000</td>
<td>CU 1,000,000</td>
<td>CU 3,000,000 x 50.00%</td>
</tr>
<tr>
<td></td>
<td><strong>Total</strong></td>
<td><strong>CU 3,000,000</strong></td>
<td></td>
<td><strong>CU 3,000,000</strong></td>
</tr>
</tbody>
</table>

In this scenario, if we assume a constant standalone selling price, the revenue recognition profile differs from that currently achieved under IAS 18 in that it is spread evenly over the three years. However, if we assume a future standalone selling price, the revenue recognition profile is the same as that under IAS 18.

Some may argue that this revenue recognition profile accurately reflects the economic characteristics of the contract – in that the entity is selling gas at a discount to the market in Years 2 and 3. Therefore, in the context of the contract, some of the cash paid by the customer in Year 1 is effectively a prepayment for gas that will be delivered in the future years.

In the latter situation, it is important to note that the only reason a similar revenue recognition profile is achieved is because we have assumed that the future standalone selling prices of gas have been built into the pricing of the contract. However, should the standalone selling prices differ to the pricing built into the contract a different recognition profile may result.
b) Treat as 1 single 3-year performance obligation

If this approach is taken, assuming the criteria are met to treat this as a single performance obligation satisfied over time and, the entity determines that the impact of the time value of money is not significant, an entity would need to:

- Determine how it will measure its progress towards complete satisfaction of that performance obligation, i.e., an output or input method
- Allocate the total transaction price based upon the measure selected
- Recognise revenue as progress is made, in line with the selected output or input method

Using an output based measurement approach, whereby the entity directly measures the value of the goods or services provided to the customer to date by reference to the MMbtu of gas delivered for which the entity has a right to invoice, the revenue recognition profile would be the same for both the fixed price and stepped price contracts. That is revenue would be recognised at the amount invoiced as and when the MMbtu of gas were delivered. This is provided the entity can demonstrate that the amount invoiced represents the value of the goods or services provided to the customer. We understand that the concept of “value” was left deliberately broad, so entities will need to assess what “value” means for its customers.

How we see it

The above analysis demonstrates that, by virtue of the steps of the model, and the new practical expedients, that the choice of how to identify the performance obligations within a contract, whether to treat them as separate performance obligations or apply the practical expedient to bundle these into one single performance obligation, decisions about how a standalone selling price is determined, and, then whether the “right to invoice” provisions can be applied, could either result in a different revenue recognition profile and increased complexity, or could actually result in a revenue recognition profile that is the same or virtually the same as that currently achieved under IAS 18.

Given the importance of these decisions, we believe the Boards should provide additional application guidance and clarity on some of these key decisions in the final standard.

Variable price contract

<table>
<thead>
<tr>
<th>Terms</th>
<th>Variable price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length of contract</td>
<td>3 years</td>
</tr>
<tr>
<td>Minimum volumes</td>
<td>MMbtu per year</td>
</tr>
<tr>
<td>Price per MMbtu</td>
<td>VWAP** in week prior to delivery of gas</td>
</tr>
</tbody>
</table>

** VWAP – volume weighted average price

Step 2: Identify the performance obligations

Each MMbtu of gas would be considered a distinct good and hence a separate performance obligation. So initially, this contract would have 3000 separate performance obligations. However as explained above, the practical expedient could be applied to combine these 3000 separate performance obligations into one performance obligation. Again, we will consider the implications of each option.
Step 3: Determine the transaction price

As a variable price contract, this step is likely to be significantly more complex than for a fixed price contract and, depending upon the terms of the arrangement, may not even be possible. This may be so where the price the customer will pay is to be based on or derived from a market price at or near the date of delivery. Such an estimate would require an entity to:

- Estimate when the customer would take delivery of the product and how much they will take at each point – which even in a one year contract would be difficult, let alone in contracts that can extend 20-30 years.

And

- Estimate the market price of gas at the point of delivery.

However, in applying certain parts of the proposed model, it may not be necessary to have to determine this at contract inception. We explore this issue further in the next section. Although, determination of the transaction price may still be needed for other parts of the model, e.g., it appears to still be required for the onerous performance obligations assessment which we discuss further below.

Steps 4 and 5: Allocate the transaction price to the performance obligations and recognise revenue

Unlike a fixed price contract, we do not believe that the outcomes of these steps will change based upon how the performance obligations are determined i.e., either 3000 separate performance obligations of 1 MMbtu each, or one single performance obligation to deliver 3000 MMbtu of gas. However, the disclosure requirements may vary.

The ED stipulates that the allocation of variable consideration, discussed above, can be made to a distinct good or service provided certain criteria are met. Where the contract is accounted for as 3000 separate performance obligations, each MMbtu would be a distinct good or service. Therefore, as each MMbtu was delivered and the transaction price was then known, this exception would allow the entity to allocate that known part of the transaction price to the distinct good or service, being the actual MMbtu delivered. The entity would not be required to allocate that known transaction price over the total number of performance obligations in the contract.

Where the practical expedient is applied, using an output based measurement approach (whereby the entity directly measures the value of the goods provided to the customer to date by reference to the MMbtu of gas delivered to the customer for which the entity has a right to invoice), revenue would be recognised at the amount invoiced as and when the MMbtu of gas were delivered, provided the entity could demonstrate that this reflected the value provided to the customer. Therefore, the revenue recognition profile would be the same as the current IAS 18 recognition profile for variable price contracts.

How we see it

The changes that have been made to the current model regarding the allocation of variable consideration are a significant change from the requirements of the 2010 ED, as is the addition of the “right to invoice” provisions.

As we explained in our oil and gas-specific revenue recognition publication issued in February 2011, under the 2010 ED, the transaction price for a variable price contract would have only been considered capable of being reasonably estimated progressively as each actual sale occurred. Therefore, as each sale occurred, the transaction price would have slowly built up and would need to have been re-estimated and reallocated across all of the performance obligations (both satisfied and unsatisfied). This would have resulted in a very unusual revenue recognition profile.

We believe the changes the Boards have made to the proposed model will now avoid this issue. This assumes that each of the goods or services delivered can be considered distinct (even after applying the practical expedient to bundle these into one single performance obligation); or provided the entity has a right to invoice, which, in most take-or-pay arrangements, they do. Consequently, we do not believe the revenue recognition profile of variable price take-or-pay arrangements will change from that currently obtained under IAS 18.
Other considerations

Onerous performance obligations

The proposed model contains onerous performance obligations requirements. These only apply where performance obligations are satisfied over time and the expected length of the contract at inception is greater than one year. Therefore, where an entity decides to treat the contract as 3000 separate performance obligations that would likely be considered to be satisfied at a point in time, these onerous performance obligations requirements would not be applicable.

However, where an entity decides to apply the practical expedient and treat the contract as one single performance obligation, and it meets the criteria to be treated as satisfied over time, the onerous test will apply if the contract is longer than one year. In undertaking this assessment, one of the inputs required is the transaction price allocated to the performance obligation, which, in this case, would be the whole contract. A performance obligation is considered onerous if the lowest cost of settling the performance obligation exceeds the amount of the transaction price allocated to that performance obligation.

As we explored earlier, for a fixed price contract, determining the transaction price of the contract would be relatively straightforward. However, determining the transaction price of a variable price contract would be more difficult, if not impossible. And whereas we illustrated earlier that, by virtue of the various practical expedients and the exception for the allocation of a variable price, determining the transaction price of a variable price contract is not necessary for revenue recognition purposes, it would still be required for the purposes of completing the onerous performance obligation assessment. Therefore to be able to complete this assessment, entities will need to make an estimate of the total transaction price.

Volumes paid for, but not taken

Another feature unique to take-or-pay arrangements are the terms relating to payments made for volumes not taken, which was explained earlier. The requirements of the proposed model may result in different accounting considerations depending on these terms.

Where payments received for unused volumes cannot be applied to future volumes, the seller has no further performance obligations, i.e., it has no obligation to deliver these unused volumes in the future. Therefore this amount can generally be recognised as revenue once the seller’s obligations no longer exist, i.e., once the customer’s right to volumes has expired unused. For most take-or-pay arrangements, such an assessment may only be possible at the end of a pre-defined period, e.g., at the end of each contract year. This is because the customer’s rights have technically not expired and the entity is still obliged to stand ready to deliver the volumes until the customer requests them right up until the end of the stated period. Also, the customer is not contractually obliged to pay the amount in relation to the unused volumes until this time, i.e., the entity does not have an unconditional right to receive cash.

This treatment would be consistent with current practice and, as such, would not represent a change.

However, with the addition of the requirements in relation to breakage, it may potentially be possible to recognise such amounts earlier, although we expect such a situation to be rare. Refer below for further discussion on the breakage requirements.

Payments can be applied to future volumes

Where payments received for unused volumes can be applied to future volumes, the seller has received consideration in advance in relation to some unsatisfied performance obligations (where each MMbtu of gas is treated as a separate performance obligation), or a partially unsatisfied performance obligation (where the practical expedient has been used to bundle the separate performance obligations into a single performance obligation). That is the delivery of the unused volumes at some point in the future. This amount represents a contract liability, which will differ from current treatment where such amounts are referred to as deferred or unearned revenue.

When a contract provides a customer with the possibility of make-up volumes, an entity will need to estimate when such future volumes are expected to be taken. This determination is important as it may require as assessment of the time value of money and/or breakage (refer below for further information on the breakage requirements). This determination will need to be made in light of the terms of the contractual agreement in conjunction with an assessment of the expected customer behaviours.
For example, such an assessment may involve considering whether the make-up volumes are:

- The first volumes to be taken at the start of the following period
- The make-up volumes can only be taken after the minimum volumes have been satisfied in the following periods
- The make-up volumes can only be taken at the end of the contract period

Tracking these make-up volumes will increase in complexity when varying amounts are progressively added to the liability. For example, there may be multiple years in which the customer does not take its minimum volumes interspersed with a period in which the customer has drawn down on the make-up volumes. Similar to approaches that are likely to be currently used, an entity may have to decide to use either a weighted average cost approach, a FIFO approach, or maybe even a LIFO approach to allocate this cumulative total to future volumes as they are delivered. Such a determination may also be impacted by the specific contractual terms, e.g., the contract may specify that any gas not taken in a particular year, say 2012, can only be used in another specific year.

Impact of the time value of money on make-up volumes

When determining how to account for the contract liability in relation to make-up volumes, the ED requires the transaction price to be adjusted to reflect the time value of money if the contract has a financing component that is significant to the contract. It then provides various factors to consider when determining whether a financing component is significant. In take-or-pay arrangements the effect may be significant where the payment from the customer is received either significantly before the transfer of goods or services.

To determine whether the time value of money is significant, an entity will need to estimate when such future volumes are expected to be taken compared to when the payment for those volumes was received.

If an entity determines that the time value of money is significant, it needs to impute interest on the contract liability. That is, an interest expense would need to be recognised on the advance payment over the period until the customer takes the additional volumes. The impact would be an increase in the contract liability and, as a result, the final amount of revenue recognised would be higher when the performance obligation is satisfied.

**Illustration 3**

Oil and gas Company A enters into a 3-year take-or-pay contract with a customer for a minimum of 1000 MMbtu of gas per year at CU 70/MMbtu.

In Year 1, Company A delivers 900 MMbtu of gas and the customer pays CU 63,000 for that gas. In addition, the customer is required to pay for the 100 MMbtu of gas that it did not take delivery of.

Therefore, at the end of Year 1, CU 7,000 has been received by Company A for the undelivered 100 MMbtu of gas. The customer is permitted to make-up the 100 MMbtu of unused gas in a subsequent period.

Satisfaction of the performance obligation relating to the 100 MMbtu is expected to occur during the last month of Year 3. Company A determines the discount rate on a similar borrowing would be 10%.

In Year 2, Company A delivers and receives payment for 1000 MMbtu of gas and the customer pays CU 70,000 for this gas.

In Year 3, Company A delivers 1100 MMbtu of gas, of which the last 100 MMbtu is delivered in the last month of the year, which are the make-up volumes. The customer pays CU 70,000 for the first 1000 MMbtu delivered in that year.

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7 The proposed model does provide a practical expedient by not requiring the consideration to be adjusted for the time value of money at contract inception, when the entity expects that the period between payment by the customer and the transfer of the promised good or service to the customer will be one year or less.
IAS 18 does not explicitly address time value of money. It is implicit in the requirement to recognise revenue at the fair value of the amount to be received. However, in practice, incorporating the impact of the time value of money is diverse.

For additional guidance on accounting for the time value of money, see Section 4.2 of our general publication.

**Breakage**

The ED discusses the concept that in certain industries customers may pay for goods or services in advance, but may not ultimately exercise all of their rights to these goods or services – either because they choose not to or are unable to. The ED refers to these unexercised rights as breakage.

The current wording within the application guidance to the ED relating to breakage, seems to initially suggest that these requirements only apply in situations where the customer has made a non-refundable upfront payment, which the entity has then recognised as a contract liability (because it has not yet satisfied the performance obligations to which the payment relates). Therefore, when considering take-or-pay arrangements and payments made in relation to unused volumes, it may be interpreted that these requirements only need to be considered in relation to payments relating to make-up volumes and only once the customer has made the prepayment.

However, we understand that these provisions may also potentially be interpreted to apply to situations where an entity is entitled to a minimum amount of consideration but where the payment for the unexercised rights is only due at some point in the future, i.e., there is no prepayment of cash as such. However, there is a specific criterion an entity would need to satisfy to be able to apply the breakage provisions in such situations, which is discussed further below.
In relation to potentially unexercised rights, i.e., breakage, the ED requires that if there is **reasonable assurance** that an entity will be entitled to a breakage amount, it will recognise the expected breakage amount as revenue in proportion to the pattern of rights exercised by the customer. However, if the entity is not reasonably assured of a breakage amount, the entity should only recognise the expected breakage amount as revenue when the likelihood of the customer exercising its remaining rights becomes remote. In take-or-pay arrangements, this may mean that an entity may be able to recognise revenue in relation to breakage amounts in an earlier period, provided that it can demonstrate it is reasonably assured that the customer will not exercise these rights. Given the nature of these arrangements and the inherent uncertainty in being able to predict a customer’s behaviour, it may be difficult to satisfy this requirement as the entity’s experience may not be able to predict the outcome at this level of certainty.

The breakage provisions may be applicable to take-or-pay arrangements because:

- The customer may not be able use the extra volumes in other areas of their own operations
- The customer may not be able store the volumes and use them after the take-or-pay contract has expired
  
  Or

- The customer may not be able to take delivery of the volumes and sell them into the market

For take-or-pay arrangements, the breakage provisions would mean that if an entity could demonstrate that it is reasonably assured that the customer will not exercise all of its rights, i.e., the customer will not take delivery of all of the minimum volume of gas, when the entity does deliver the units of gas to the customer, the amount of revenue it recognises on each of those units may be higher. For example, if the minimum amount of gas was 1000 MMbtu at CU 10 per MMbtu, and the entity was reasonably assured that the customer would only take 900 MMbtu, then as the entity delivered the 900 MMbtu, the amount of revenue it would recognise for each of those MMbtu, would be higher. This can be demonstrated as follows – the total minimum transaction price for Year 1 = 1000 MMbtu x CU 10 = CU 10,000; if the entity was reasonably assured of the breakage amount, i.e., that proportion that relates to the 100 MMbtu which will not be taken, the entity would recognise the full amount of the transaction price when it delivered the 900 MMbtu, which would mean the revenue recognised per MMbtu would be CU 10,000/900 MMbtu = CU 11.11

Being able to apply these provisions means an entity may be able to accelerate the timing of revenue recognition. However, in our view, to be able to do this, an entity would need robust evidence to support its assertion that it was reasonably assured the customer would not take its full entitlement and this potentially may be difficult to do.
An alternate view may be that the breakage amount only relates to the rights that have already been exercised in the contract. This would lead to full recognition of the breakage amount when reasonable assurance is achieved, or if reasonable assurance cannot be achieved, when the likelihood of the customer exercising the rights becomes remote.

**How we see it**

The proposed new revenue recognition model will increase the complexity in accounting for take-or-pay arrangements in which the customer is entitled to make-up volumes.

In such situations, the entity will need to determine when it expects the customer to take these make-up volumes so it is able to assess whether the time value of money is significant. If the time value of money is determined to be significant, the entity will then need to have the appropriate processes and systems in place to be able to calculate and recognise the associated interest expense. Likewise, it will need to understand at what point such amounts can be recognised as revenue.

While it may also be possible that due to the breakage provisions, entities may be able to recognise revenue earlier than that currently achieved, robust evidence would be needed to support such a treatment. We also believe that to minimise divergence, some additional application is needed to clarify how the breakage provisions are to be applied.

**Disclosures**

In addition to the new recognition and measurement requirements to be considered for take-or-pay arrangements, there are new disclosure requirements. Those specifically applicable to take-or-pay arrangements include the following:

- Contract liabilities – a detailed roll forward is required which discloses each of the key movements in this balance from one reporting period to the next. This would apply to payments made in relation to make-up volumes

- Allocation of the transaction price to unsatisfied performance obligations in contracts with a duration of more than one year – while it may not be apparent, this disclosure requirement applies to both performance obligations that are fully incomplete, as well as those that are partially incomplete. Therefore, whether an entity chooses, for contracts of this duration, to treat each MMbtu of gas as a separate performance obligation, or whether it decides to bundle these into one single performance obligation, new disclosure requirements may be required. Specifically, an entity will be required to disclose the aggregate amount of the transaction price allocated to remaining performance obligations and it will also be required to explain when it expects to recognise that amount of revenue. Such disclosures can be quantitative or qualitative.

For fixed price contracts, while this is an additional disclosure requirement which will require the collation of additional information, determining these amounts will not be difficult as the price per performance obligation is fixed and the entity would know the time bands, e.g., years, in which revenue will be recognised. However, this will be more difficult, if not almost impossible, for variable price contracts due to the complexities in determining a variable transaction price (as explained above).

However, where an entity elects to apply the practical expedient and bundle the individual performance obligations into one single performance obligation and then it is able to apply the “right to invoice” output approach as its method of measuring progress towards the complete satisfaction of that performance obligation, another practical expedient is provided such that the above disclosures for the remaining transaction price are not required.
Summary of take-or-pay arrangements

The proposed new revenue recognition model could have practical implications for, and may increase the complexity of, the accounting for take-or-pay arrangements. While, in some situations, the exact impact of the standard may still be unclear, the following impacts appear likely:

- For both fixed and variable price contracts, the inclusion of a number of new practical expedients, specifically those relating to the ability to bundle multiple distinct goods and services into one performance obligation and the ability to recognise revenue based upon invoiced amounts, seems to indicate that the accounting for these take-or-pay arrangements may not change from current practice.
- However, if an entity decides not to, or cannot use, the practical expedient for bundling — this may warrant different considerations and may lead to different outcomes.
- For variable price contracts the changes to the 2010 ED regarding allocation of variable consideration seem to have simplified the accounting for some aspects of these contracts and may mean the accounting will be the same as current practice.
- For fixed price contracts however, the revenue recognition profile of these contracts may change — but this will depend on how these contracts are priced, e.g., one fixed price compared to stepped prices, and how the standalone selling prices are determined.
- Where customers are entitled to make-up volumes, accounting for these will change, and could potentially become more complex.
- New disclosures will be required, which will mean an entity has to capture, collate and disclose new types of information.

Next steps

As the nature of contracts within the oil and gas sector varies significantly, as do their complexity, entities should familiarise themselves, not only with the matters outlined in this supplement, but also with the details of the new revenue recognition model in general. This will assist them in:

- Fully analysing the potential impact of these proposals on their common transactions.
- Identifying any situations where the accounting may not reflect the substance of a transaction or may be different from the current accounting.
- Identifying potential implementation issues.

This will also assist them in providing input to the IASB as they proceed to finalising the standard and in keeping their Audit Committee, Board and auditors apprised of the potential implications. Furthermore, entities should consider the process for communications with shareholders, analysts and other users.
Ernst & Young’s Oil & Gas Contacts

The oil and gas sector is constantly changing. Increasingly uncertain energy policies, geopolitical complexities, cost management and climate change all present significant challenges.

Ernst & Young’s Global Oil & Gas Center supports a global practice of over 9,000 oil and gas professionals with technical experience in providing assurance, tax, transaction and advisory services across the upstream, midstream, downstream and oilfield service sub-sectors. The Center works to anticipate market trends, execute the mobility of our global resources and articulate points of view on relevant key sector issues. With our deep sector focus, we can help your organization drive down costs and compete more effectively to achieve its potential.

For further information, please contact:

Dale Nijoka
Global Oil & Gas Leader
+1 713 750 1551
dale.nijoka@ey.com

Allister Wilson
Global Oil & Gas Assurance Leader
+44 20 7951 1443
awilson@uk.ey.com

Richard Addison
Assurance Partner
+44 20 7951 0299
raddison@uk.ey.com

Tracey Waring
Global Oil & Gas IFRS Leader
+44 20 7980 0646
tracey.waring@uk.ey.com

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