



Oil and Gas

Accounting, Financial
Reporting, and Tax Update

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Foreword

January 2016

Industry Overview

The oil and gas (O&G) sector faced challenging times in 2015. Oil prices started to decline in the fourth quarter of 2014 and trended in the low \$50s per barrel in January 2015. Despite peaking at around \$60 per barrel during the months of May and June, indications of price recovery were short-lived, with WTI at \$37 per barrel at year-end 2015.

Because of the dramatic decline in oil prices, industry participants focused on driving operational efficiencies by reducing costs through innovation and other measures. The year 2015 brought significant decreases in capital spending by exploration and production (E&P) companies, which led to (1) a reduction in the number of rigs in the fields and (2) the renegotiation and cancellation of contracts with service providers.

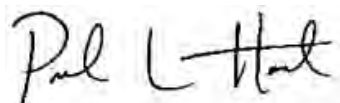
Despite the steep decline in prices, the resilient U.S. O&G industry has not decreased production significantly below prior-year levels. At the dawn of 2016, firms throughout the industry are leaner and poised to prove yet again that the U.S. O&G industry is competitive globally even in the current low-price environment.

About This Document

We are pleased to present our third annual Accounting, Financial Reporting, and Tax Update for the O&G sector. This publication discusses accounting, tax, and regulatory matters that O&G entities will need to consider, including updates to SEC, FASB, and tax guidance with a specialized focus on industry accounting topics affecting O&G companies. New in this year's publication is a focused discussion on accounting and reporting considerations related to the new leases standard expected to be issued in early February 2016.

Certain sections of this publication are designed to help you understand and address potential challenges in the accounting for and reporting of topics on which the FASB has recently issued proposed standards or final standards that are not yet effective. Our publication discusses such proposals and codified guidance and highlights nuances that could affect the O&G industry, helping you plan a roadmap for future regulatory and reporting environments.

We hope you find this update a useful resource, and we welcome your feedback. As always, we encourage you to contact your Deloitte team or any of the Deloitte specialists in [Appendix C](#) for additional information and assistance.



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Section 1

Industry Hot Topics

Accounting Issues Related to the Declining Oil and Natural Gas Commodity Prices

Summary

Commodity prices in the oil and gas (O&G) industry have changed dramatically over the past 18 months. Whereas oil prices approached \$90 per barrel in January 2014 and were slightly above \$100 per barrel in July of that year, they have since undergone a steep, steady decline, with West Texas and Brent crude prices below \$30 per barrel after the first couple of weeks of January 2016. Natural gas prices tell a similar story, with the Henry Hub spot prices rising from \$4.32 per million British thermal units (MMBtu) on January 2, 2014, to a peak of \$7.78 per MMBtu in March 2014 before settling near \$3 per MMBtu in January 2015 and holding at just over \$2 per MMBtu as of January 2016. The lower oil and natural gas prices have already had an impact on the O&G industry as companies have been forced to reevaluate how they will operate in this new lower-commodities-cost environment.

O&G companies will need to evaluate how and where they are conducting their exploration and production (E&P) activities. For example, while there is a definite upside to using hydraulic fracturing techniques in mineral-rich shale formations across the United States, there are questions about the cost-effectiveness and environmental implications of such activities, although many companies in 2015 were able to achieve significant cost reductions related to drilling and completing oil and natural gas wells. Similar questions have been raised in connection with deepwater drilling activities in the Gulf of Mexico, which increased markedly during 2014 and 2015. Further, capital budgets were significantly reduced for fiscal year 2015, and the sharp decline in operating cash flows is likely to be further affected by reductions in production. Budgets for 2016 are expected to be reduced below their 2015 levels; such a reduction will lead to overall declines in production and consequently will have a direct impact on all sectors within the O&G industry.

The decline in oil and natural gas prices is likely to have operational and accounting impacts on many O&G companies, and it can also be expected to have an impact on non-O&G companies that participate in the industry.

Upstream

The lower oil and natural gas prices may reduce the viability of drilling since the drilling and/or operating costs of extracting the oil or natural gas may exceed the revenue generated. Therefore, entities should consider their particular facts and circumstances and any potential early warning signs of impairment, as well as apply the appropriate accounting guidance.

Companies that engage in exploration and development can account for their operations by using either the successful-efforts method or the full-cost method. The fundamental differences between these two methods lie in their treatment of seismic costs and exploration drilling for new O&G reserves. The accounting method used will directly affect how net income and cash flows are reported.

Under the successful-efforts method, costs related to the successful identification of new reserves may be capitalized while costs related to unsuccessful exploration efforts (e.g., drilling efforts that result in a dry hole) would be immediately recorded on the income statement. Conversely, the full-cost method allows companies to capitalize nearly all costs related to the exploration and development of new reserves regardless of whether their efforts were successful.

Successful-Efforts Companies

Companies that use the successful-efforts method apply the guidance in ASC 932-360-35 and ASC 360-10-35 to account for the impairment of their O&G assets. Such guidance addresses (1) the timing of impairment testing and impairment indicators, (2) measurement of an impairment loss, (3) the level at which an impairment is assessed, and (4) recognition of an impairment loss.

Under the successful-efforts method, a company generally performs a multistep impairment analysis in accordance with ASC 360 when considering whether to assess proved O&G properties for indications of impairment. Generally, this analysis consists of determining when events or circumstances indicate that the carrying value of the company's oil and natural gas properties may not be recoverable.

Proved properties in an asset group should be tested for recoverability whenever events or changes in circumstances indicate that the asset group's carrying amount may not be recoverable. Generally, companies that apply the successful-efforts method will perform an annual recoverability assessment upon receiving their annual reserve report by preparing a cash flow analysis as the necessary information becomes readily available. See [Section 3](#) for additional impairment and valuation considerations for entities applying the successful-efforts method.

Thinking It Through

Companies that use the successful-efforts method should evaluate the impact of the declining commodity prices in light of the following key accounting considerations:

- Proved oil and natural gas reserves.
- Reserve risk factor determination.
- Development plans for proved undeveloped (PUD) reserves.
- Economic limitations.
- Capital cost used for PUD reserves, probable reserves (P2), possible reserves (P3), and contingent resources.
- Cost aggregation.

Full-Cost Companies

To assess whether their O&G assets are impaired, E&P companies that use the full-cost method of accounting should apply the guidance in Regulation S-X, Rule 4-10; SAB Topic 12.D; and FRC Section 406.01.c. Like successful-efforts accounting guidance, this guidance addresses (1) the timing of impairment testing and impairment indicators, (2) measurement of an impairment loss, (3) the level at which an impairment is assessed, and (4) recognition of an impairment loss.

Under the full-cost method, a full-cost ceiling test must be performed on proved properties each reporting period.

The full-cost accounting approach requires a write-down of the full-cost asset pool when net unamortized cost less related deferred income taxes exceeds (1) the discounted cash flows from proved properties (i.e., estimated future net revenues less estimated future expenditures to develop and produce proved reserves), (2) the cost of unproved properties not included in the costs being amortized, and (3) the cost of unproved properties included in the costs being amortized. The write-down would be reduced by the income tax effects related to the difference between the book basis and the tax basis of the properties involved. See [Section 3](#) for additional impairment and valuation considerations for entities applying the full-cost method.

Thinking It Through

Companies that use the full-cost method should evaluate the impact of the declining commodity prices in light of the following key accounting considerations:

- Development plans for PUD reserves.
- Capital and operating cost.
- Operating cost.
- The trailing 12-month prices for 2015, which are approximately \$52 per barrel for oil and \$1.80 per thousand cubic feet (Mcf) for natural gas. Unless prices recover in the near term, the trailing 12-month prices in 2016 will continue to decline. Consequently, it is likely that impairment risk will continue into 2016.

Unproved Oil and Natural Gas Properties

Companies should assess unproved properties periodically (i.e., at least annually) to determine whether they have been impaired. The assessment of these properties is based mostly on qualitative factors. The key considerations are:

- Development intent.
- The primary lease term.
- Recent development activity, including:
 - Drilling results of the company and others in the industry.
 - Recent market values for undeveloped acreage.

Oil and Natural Gas Reserves

The declining oil prices will have a direct impact on the underlying prices received for production, which in turn could adversely affect the following:

- Loss of proved reserves because of economic limitations. Note that under Regulation S-X, Rule 4-10(a)(22), such reserves are defined as those quantities of petroleum that are expected to be commercially recoverable **under existing economic conditions**.
- Loss of PUD reserves as a result of changes to an entity's development plans. Note that under Regulation S-X, Rule 4-10, reserves should be classified as PUD **"only if a development plan has been adopted indicating that [the locations] are scheduled to be drilled within five years"** (emphasis added).
- Overall reduction of the underlying cash flows attributable to oil and natural gas reserves.

Liquidity

The declining oil and natural gas price environment may similarly affect the current and future liquidity position of companies in the O&G industry, inclusive of all industry sectors. This industry has a unique ability to preserve cash by slowing development activities. While a reduction in such activities will provide for near-term liquidity, it is likely to affect production and future cash flows in future years. This expectation is likely to be a key consideration for upstream companies as they address the disclosure requirements in Regulation S-K, Item 303.

Under the going-concern assumption, a company is viewed as continuing in business for the foreseeable future. General-purpose financial statements are prepared on a going-concern basis unless management either (1) intends to liquidate the company or cease operations or (2) has no realistic alternative to doing so. When it is appropriate to use the going-concern assumption, assets and liabilities are recorded on the basis that the company will be able to realize its assets and discharge its liabilities in the normal course of business.

Since the going-concern assumption is a fundamental principle in the preparation of financial statements, such preparation requires management to assess the company's ability to continue as a going concern.

Key liquidity considerations in light of the decline in oil and natural gas commodity prices include, but are not limited to, the following:

- Asset-based lending tied to reserves, typically in the form of bank credit facilities.
- Redetermination period (note that for most agreements, there is a semiannual redetermination period that will occur before the next financial statements are issued) and arrangement tenor.
- Financial covenant violations:
 - As of the balance sheet date.
 - After the balance sheet date but before the report issuance date.
 - Expected after the report issuance date.

Management should apply the guidance in ASC 470-10-45-1 and ASC 470-10-45-11.

Disclosure Considerations

O&G companies should focus on risk-based and early-warning disclosures when impairments are expected to occur into the future. The SEC may consider a company's MD&A deficient if (1) it does not discuss known trends that could change undiscounted cash flows in future periods and thereby trigger an impairment in a future period or (2) it does not disclose reasonably possible future write-downs. In these circumstances, a company should discuss in MD&A (1) the significant assumptions used, (2) the subjectivity of such assumptions, (3) the possibility that an impairment write-down may be required in the future if the expected future cash flows decline, and (4) the fact that the cash flows used are management's best estimate. In addition, the SEC staff has stated that it expects consistency in assumptions and estimates used to determine expected future cash flows for impairment analyses and MD&A. For example, the SEC staff would challenge a registrant if it uses pessimistic assumptions in estimating expected future cash flows to support an impairment write-down but describes an optimistic outlook for operations in MD&A. MD&A disclosures should be consistent with management's support for expected future cash flows used to test impairment.



Further, O&G companies should consider the guidance in Regulation S-K, Item 303, under which registrants are required to describe in MD&A known trends or uncertainties, such as declining oil prices, and to disclose whether such trends or uncertainties are expected to have an unfavorable or favorable material impact on revenue or sales. Given the declining price environment, engagement teams should review the guidance in Item 303 to ensure that proper disclosures are made.

Oilfield Services

O&G companies in the upstream sector have begun to curtail the number of drilling rigs that they are actively running in their programs. Accordingly, the expectation is that (1) there will be a slowdown in services provided as a result of fewer actively working rigs in 2016 and, therefore, (2) fewer wells will be completed and brought online. Like companies in the midstream sector, oilfield service companies will need to consider the potential impacts of a reduction in upstream activity on their future cash flows. Considerations include:

- Asset backlog activity.
- Contract strength, including cancellation provisions.
- Asset useful life and related history of asset utilization in a depressed-commodity-price environment.

Midstream

If the upstream sector begins to curtail drilling operations, production is likely to decrease. Consequently, the midstream sector should focus on impairment indicators as a result of the potential decline in production. Management should evaluate the impairment considerations in accordance with ASC 360 for the purpose of determining whether a triggering event has taken place.

Other Matters

The significant drop in oil and natural gas prices may also trigger a need to perform an assessment of any recorded goodwill. When evaluating goodwill in these circumstances, O&G companies should consider the synchronicity of value under the income approach and value under the market approach.

If a company's impairment assessments lead to an impairment charge, the entity may be faced with significant losses in the current year and, potentially, cumulative losses over recent years, leading to a reassessment of the realizability of the company's deferred tax assets, including those directly related to the impaired O&G assets.

Many non-O&G companies may be negatively affected by such impairment since O&G assets may represent a significant portion of their direct investment portfolio inclusive of both debt and equity holdings, which may be held within the companies' investment portfolio or within a pension portfolio. The duration of the downturn and forward expectations should be considered in the evaluation of whether a decline is other than temporary.

M&A Update

In 2015, the O&G industry experienced a dramatic drop-off in M&A activity in terms of the number of deals completed. Despite this, a few large iconic transactions kept cumulative deal values at levels similar to those experienced in the previous two years. Aside from these large transactions, however, overall M&A deal value was low compared with that of the past several years.

Currently, the industry appears to be in a holding pattern while the implications and impacts of the oil price downturn play out. Whereas expectations of a short-lived low-price environment persisted through the end of 2014, acceptance of the lower pricing environment began to grow over the course of 2015, resulting in market participants' retrenching, cutting costs, and delaying capital projects to conserve cash. In some cases, production has been maintained to boost cash flows, and remaining hedged positions continue to provide support.

This period of uncertainty and adjustment has given rise to value gaps. In 2015, potential sellers placed premium values on attractive assets, while potential buyers did not yet see the bargains they were anticipating. At the same time, lenders to the industry did not, to any great extent, seek radical corrective action during the spring or fall redeterminations of borrowing bases that might have increased the pressure on highly leveraged companies to sell assets. Early in 2015, we experienced examples of North American producers' tapping into equity markets as an alternative to rolling over debt or raising new debt. This strategy has helped sustain activity through the downturn without further weakening balance sheets, but it could be risky if the dilution effect depresses stock prices.

These factors, especially the availability of capital, may be changing and could influence the environment for deal making in 2016. In addition, hedge protection is running out for many producers that either have not taken on new hedges in this low-price environment or have entered into new positions for 2016 at significantly lower values than 2015 levels. The longer the price downturn lasts — and, perhaps more important, the longer market participants think it will last — the more pressure builds from lenders for highly leveraged operators to shore up balance sheets with asset sales. Under this pressure, valuation gaps may erode, in which case buyers that see bargain opportunities are likely to emerge from the ranks of (1) companies with available cash and/or lower leverage or (2) private equity sources.

Mexico Energy Reform

Overview of the Program

The December 2013 amendments to the Mexican constitution, together with related legislation, have effectively opened the Mexican O&G energy market to private and local investors for the first time since the establishment of Petróleos Mexicanos (PEMEX). Mexico's new energy reform ends 75 years of a state monopoly in the local O&G and electricity sectors. The objectives of the reform are to (1) build the Mexican energy industry by attracting private capital and technical expertise, (2) maximize O&G revenue, and (3) boost economic growth through 2025.

Under this program, the Mexican government will enter into arrangements with foreign investors to exploit underused, unconventional O&G reserves and increase competition in the electricity sector to lower local prices. While subsoil hydrocarbons will remain the property of the Mexican government, private entities (referred to as contractors) will be permitted to participate in *exploration and extraction* activities (as defined by the Mexican government) in varying degrees by entering into one of four types of arrangements:

- License contracts.
- Profit-sharing agreements.
- Production-sharing agreements.
- Service contracts.

The Mexican government will execute the various arrangements by using a two-stage bidding system. In the first stage, bidders are chosen on the basis of certain criteria, including qualifications, financial strength, work program, and minimum investment commitment. In the second stage, the bidders that have been selected are considered mainly on the basis of the profitability of the arrangement to the Mexican government.

Activity to Date

Energy reform in Mexico is being implemented in several phases. In the first phase ("Round Zero"), the Mexican government awarded to PEMEX 83 percent of the country's probable reserves and 21 percent of its prospective resources (mainly conventional fields, but also deepwater and unconventional fields).

The second phase ("Round 1"), which is currently under way, represents the first group of biddings among interested contractors:

- *First bidding* — Started in December 2014 and finalized on July 15, 2015, the first bidding comprised 14 exploration blocks in shallow waters under production-sharing agreements. Twenty-five entities (18 individual companies and 7 consortiums) were prequalified, and 9 entities ultimately participated in the bidding. Of the 14 available blocks, 2 were awarded — to the consortium formed by (1) Sierra Oil and Gas, (2) Talos Energy, and (3) Premier Oil. Contracts were signed on September 4, 2015.
- *Second bidding* — Begun in February 2015 and ended on September 30, 2015, the second bidding comprised nine fields, grouped in five production blocks (contractual areas) with proved reserves in shallow waters under production-sharing agreements. Fourteen entities (10 individual companies and 4 consortiums) were prequalified; 9 companies presented proposals. Three of the five blocks were awarded as follows:
 - *Block 1* — To ENI International B.V.
 - *Block 2* — To Pan American Energy LLC and E&P Hidrocarburos y Servicios S.A.
 - *Block 3* — To Fieldwood Energy LLC and Petrobal S.A.P.I. de C.V.

It is estimated that over the next 25 years, \$3.1 billion will be invested in the awarded blocks, which are expected to produce a peak of 90 tbd of crude oil equivalent by 2018. Contracts with ENI International B.V. were signed by November 30, 2015, and contracts with the Block 2 and Block 3 entities were signed on January 7, 2016.

- *Third bidding* — Initiated in May 2015 and ended on December 15, 2015, the third bidding was for production in 25 mature onshore fields (contractual areas) under license agreements. Of the 25 fields, 17 hold oil reserves and 8 are natural gas reservoirs. Fifty-two entities (36 individual companies and 16 consortiums) were prequalified, and 42 entities presented proposals. By the end of the bidding, all 25 blocks were awarded, which was an exceptional result. The awards went to 22 companies (14 entities not counting individual companies within consortiums), of which 18 were Mexican, 2 were American, 1 was Dutch, and 1 was Canadian.

Investment in the awarded blocks is estimated to reach \$620 million over the next five years and \$1.1 billion over 25 years. Production is estimated to reach 77 tbd by 2018.

- *Fourth bidding* — This bidding process, which started on December 17, 2015, and is expected to end by the first quarter of 2017, is for exploration and production in 10 deepwater contractual fields under license agreements for 35 years. Four of these fields are located in the Perdido area, near the U.S. Gulf Coast, and are expected to produce light crude oil; two of the Perdido fields are at a depth of more than 5,000 feet, whereas the other two Perdido fields are at a lesser depth. The remaining six fields are located in what is called the “Cuenca Salina del Istmo” and are expected to produce heavy and light crude oil as well as gas; of these fields, two are at a depth of more than 5,000 feet and the other four are at a lesser depth.

Investment in the 10 fields is expected to total \$44.4 billion over 35 years.

Next Steps

In October 2015, Mexico’s Ministry of Energy announced a five-year bidding plan that will continue through 2019 for exploration and production areas. The plan includes 96 exploration areas and 237 product areas.



Section 2

Accounting Standards Codification Update

Reporting of Discontinued Operations

Background

On April 10, 2014, the FASB issued [ASU 2014-08](#), which amends the definition of a discontinued operation in ASC 205-20 and requires entities to provide additional disclosures about disposal transactions that do not meet the discontinued-operations criteria. In addition to changing how entities identify and disclose information about disposal transactions under U.S. GAAP, the ASU elevates the threshold that a disposal transaction must meet to qualify as a discontinued operation (since too many disposal transactions were qualifying as discontinued operations under existing guidance).

Under the previous guidance in ASC 205-20-45-1, the results of operations of a component of an entity were classified as a discontinued operation if all of the following conditions were met:

- The component “has been disposed of or is classified as held for sale.”
- “The operations and cash flows of the component have been (or will be) eliminated from the ongoing operations of the entity as a result of the disposal transaction.”
- “The entity will not have any significant continuing involvement in the operations of the component after the disposal transaction.”

The new guidance eliminates the second and third criteria above and instead requires discontinued-operations treatment for disposals of a component or group of components that represents a strategic shift that has or will have a major impact on an entity’s operations or financial results.

Thinking It Through

When a successful-efforts O&G entity disposes of a segment or component (whether a reportable segment, operating segment, subsidiary, operating basin, or another component), the critical consideration of the disposal’s significance to the entity and its financial statement users is whether the disposal represents a strategic shift. Historically, successful-efforts O&G entities generally used the full-cost considerations for each cash generating unit as a proxy to determine whether the guidance on discontinued operations was applicable. However, now such entities will have to take additional considerations into account to determine whether a strategic shift has occurred. Given the ASU’s lack of clarity on the topic, successful-efforts O&G entities will need to use judgment in determining whether a strategic shift has occurred.

Scope

The ASU retains the discontinued-operations scope exception for oil and gas properties accounted for under the full-cost method but removes the exceptions in ASC 360-10-15-5 (e.g., the exception in ASC 360-10-15-5(e) for investments in equity securities accounted for under the equity method). Further, unlike current U.S. GAAP, the ASU includes a “business or nonprofit activity that, on acquisition, meets the criteria to be classified as held for sale” in the definition of a discontinued operation.

Presentation and Disclosure

The ASU (1) expands disclosure requirements for transactions that meet the definition of a discontinued operation and (2) requires entities to disclose information about individually significant components that are disposed of or held for sale and do not qualify as discontinued operations.

In addition, the ASU requires entities to reclassify assets and liabilities of a discontinued operation for all comparative periods presented in the statement of financial position. Before these amendments, ASC 205-20 neither required nor prohibited such presentation.

Thinking It Through

In certain situations, discontinued business units/strategies may be completely rolled off from financial data during the current period. However, in preparing their disclosures, O&G entities should be careful to include such zero balances in disclosure sections for which comparative prior periods must be presented because of the existence of balances (e.g., disclosures about derivative gross volume under ASC 815).

Further, regarding the statement of cash flows, an entity must disclose, in all periods presented, either (1) operating and investing cash flows or (2) depreciation and amortization, capital expenditures, and significant operating and investing noncash items related to the discontinued operation. This presentation requirement represents a significant change from previous guidance.

See Deloitte's April 22, 2014, [Heads Up](#) for further discussion of the ASU 2014-08 disclosure requirements.

Effective Date and Transition

The ASU is effective prospectively for all disposals (except disposals classified as held for sale before the adoption date) or components initially classified as held for sale in periods beginning on or after December 15, 2014. Early adoption is permitted.

Going Concern

Background

On August 27, 2014, the FASB issued [ASU 2014-15](#), which contains guidance on (1) how to perform a going-concern assessment and (2) when and how to disclose going-concern uncertainties in the financial statements.

Under U.S. GAAP, an entity's financial reports reflect its assumption that it will continue as a going concern until liquidation is imminent. However, before liquidation is deemed imminent, an entity may have uncertainties about its ability to continue as a going concern. Because there are no current U.S. GAAP requirements related to disclosing such uncertainties, auditors have used applicable auditing standards to assess the nature, timing, and extent of an entity's disclosures. The ASU is intended to reduce the diversity in practice that has resulted from this lack of specific going-concern disclosure requirements.

Time Horizon

In each reporting period (including interim periods), an entity is required to assess its ability to meet its obligations as they become due for one year after the issuance date of the financial statements.

Disclosures

An entity must provide certain disclosures if "conditions or events raise substantial doubt about [the] entity's ability to continue as a going concern." The ASU defines substantial doubt as follows:

Substantial doubt about an entity's ability to continue as a going concern exists when conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year after the date that the financial statements are issued The term *probable* is used consistently with its use in Topic 450 on contingencies.

In applying this disclosure threshold, an entity must evaluate "relevant conditions and events that are known and reasonably knowable at the date that the financial statements are issued." Reasonably knowable conditions or events are those that can be identified without undue cost and effort.

If an entity triggers the substantial-doubt threshold, its footnote disclosures must contain the following information, as applicable:

Substantial Doubt Is Raised but Is Alleviated by Management's Plans	Substantial Doubt Is Raised but Is Not Alleviated
• Principal conditions or events. • Management's evaluation. • Management's plans.	• Principal conditions or events. • Management's evaluation. • Management's plans. • Statement that there is "substantial doubt about [the] entity's ability to continue as a going concern."

The ASU explains that these disclosures may change over time as new information becomes available.

Effective Date

The guidance in the ASU is "effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016." Early application is permitted.

For additional information about the going-concern ASU, see Deloitte's August 28, 2014, [Heads Up](#).

Consolidation

Background

In February 2015, the FASB issued [ASU 2015-02](#), which amends the consolidation requirements in ASC 810. The issuance of the ASU concluded the FASB's ongoing project to eliminate the deferral of ASU 2009-17 (formerly Statement 167) for certain entities. While the Board's focus for the project was largely on the investment management industry, the amendments in the ASU could also affect an O&G entity's consolidation conclusions. Specifically, O&G entities should consider whether the ASU's provisions regarding (1) when limited partnerships and similar entities should be consolidated, and (2) variable interests held by the reporting entity's related parties or de facto agents affect its consolidation conclusions. These provisions may have an impact on certain investment structures entered into by O&G entities.

For a comprehensive review of ASU 2015-02, see Section E.5 of Appendix E in Deloitte's [Consolidation — A Roadmap to Identifying a Controlling Financial Interest](#).

Determining Whether a Limited Partnership (or Similar Entity) Is a VIE

The ASU amends the definition of a VIE for limited partnerships and similar entities. Under the ASU, a limited partnership is considered a VIE regardless of whether it has sufficient equity or meets the other requirements to qualify as a voting interest entity **unless** a single LP or a simple majority of all partners (including interests held by the GP and its related parties) has substantive kick-out rights (including liquidation rights) or the LPs have participating rights. As a result of the amendments to the definition of a VIE for limited partnerships and similar entities, partnerships historically not considered VIEs will need to be evaluated under the new VIE consolidation model. Conversely, partnership arrangements that include simple-majority kick-out or participating rights (rather than single-partner rights) may no longer be VIEs.

Thinking It Through

O&G entities often enter into limited partnerships as a mechanism to finance new capital projects. Although the consolidation conclusion may not change, an O&G entity will need to evaluate all of its limited partnership interests under the new guidance described above. In addition, even if an O&G entity determines that it does not need to consolidate a VIE, it would have to provide the existing extensive disclosures for any VIEs in which it holds a variable interest.

Determining Whether an Entity Other Than a Limited Partnership (or Similar Entity) Is a VIE

The ASU clarifies how a reporting entity should evaluate the condition in ASC 810-10-15-14(b)(1) (whether the equity holders (as a group) have power) for entities other than limited partnerships. Specifically, the ASU clarifies that in situations in which the equity holders have delegated the decision-making responsibility, and the decision maker's fee arrangement is a variable interest under ASC 810-10-55-37, the evaluation of this criterion should focus on whether the equity holders have power over the legal entity's most significant activities through their equity interests. In making this assessment, the reporting entity should consider whether the equity holders have the right to replace the decision maker. This is a significant change from the previous guidance, under which kick-out rights were only considered if they were held by a single party.

Determining Who Should Consolidate

In a manner consistent with the current guidance, a reporting entity would be considered the primary beneficiary of a VIE under the ASU (and would therefore be required to consolidate the VIE) when it has met the power and economics conditions. This would apply to all entities that are VIEs, including limited partnerships and similar entities that are VIEs.

Under the ASU, the evaluation of who controls a limited partnership that is **not** considered a VIE focuses on the kick-out or liquidation rights held by the "unrelated" LPs. That is, the analysis would concentrate on whether any of the LPs have the substantive ability to unilaterally dissolve the limited partnership or otherwise remove the GP without cause and, if so, should consolidate the partnership.

Effects of Related Parties

The ASU significantly amends how variable interests held by a reporting entity's related parties or de facto agents affect its consolidation conclusion. Among other items, the need to perform the related-party tiebreaker test (as well as mandatory



consolidation by one of the related parties) will be less frequent under the ASU than under current U.S. GAAP. If power is not considered shared among the related parties, the related-party tiebreaker test would be performed only by parties in the decision maker's related-party group that are under common control and that together possess the characteristics of a controlling financial interest. In this situation, the purpose of the test would be to determine whether the decision maker or a related party under common control of the decision maker is required to consolidate the VIE.

In addition, if neither the decision maker nor a related party under common control is required to consolidate a VIE but the related-party group (including de facto agents) possesses the characteristics of a controlling financial interest, and

substantially all of the VIE's activities are conducted on behalf of a single entity in the related-party group, that entity would be the primary beneficiary of the VIE.

Effective Date and Transition

For public business entities (PBEs), the ASU's guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. For entities other than PBEs, the ASU's guidance is effective for annual periods beginning after December 15, 2016, and interim periods beginning after December 15, 2017. The ASU would allow early adoption for all entities but would require entities to apply the guidance as of the beginning of the annual period containing the adoption date. Modified retrospective application (including a practicability exception) would be required, with an option for full retrospective application.

Thinking It Through

When reviewing the new consolidation guidance, O&G entities should carefully consider the extent to which they may need to revise processes and new controls to apply the new ASU, particularly those processes and controls related to an entity's obtaining the information necessary to meet the VIE disclosure requirements. In addition, O&G entities should consider the effect of the new guidance when entering into new transactions.

Pushdown Accounting (ASU 2014-17 and ASU 2015-08)

Background

In November 2014, the FASB issued [ASU 2014-17](#), which gives an acquired entity the option of applying pushdown accounting in its stand-alone financial statements upon a change-in-control event. Before ASU 2014-17, there was limited guidance in U.S. GAAP on determining whether an acquired entity can establish a new accounting and reporting basis in its stand-alone financial statements (commonly referred to as "pushdown" accounting). ASC 805-50-S99-1 through S99-41 contain pushdown accounting requirements for SEC registrants. Under this guidance, pushdown accounting is (1) prohibited when 80 percent or less of an entity's ownership is acquired, (2) permitted when between 80 percent and 95 percent is acquired, and (3) required when 95 percent or more is acquired.

Key Provisions of ASU 2014-17

An acquired entity that elects pushdown accounting would apply the measurement principles in ASC 805 to push down the measurement basis of its acquirer to its stand-alone financial statements. In addition, the acquired entity would be required to provide disclosures that enable "users of financial statements to evaluate the effect of pushdown accounting."¹

ASU 2014-17 also concluded that when applying pushdown accounting, an acquired entity would be:

- Prohibited from recognizing acquisition-related debt incurred by the acquirer unless the acquired entity is required to do so in accordance with applicable U.S. GAAP (e.g., because the acquired entity is legally obligated).
- Required to recognize the acquirer's goodwill.
- Prohibited from recognizing bargain purchase gains that resulted from the change-in-control transaction or event; instead, the acquiree would recognize such gains as an adjustment to equity (i.e., additional paid-in capital (APIC)).

The ASU also gives a subsidiary of an acquired entity the option of applying pushdown accounting to its stand-alone financial statements, even if the acquired entity (i.e., the direct subsidiary of the acquirer) elected not to apply pushdown accounting.

The ASU does not apply to common-control transfers; the guidance on accounting for transactions by entities under common control is included in ASC 805-50. A company that receives the net assets or equity interests in a common-control transfer should record those net assets or equity interests at the transferor's carrying amounts. However, if pushdown

¹ Entities would achieve that disclosure objective by providing the relevant disclosures required by ASC 805.

accounting was not applied by the transferor, the financial statements of the receiving entity would reflect the transferred net assets at the historical cost of the parent of the entities under common control, which would result in the parent's basis being pushed down to the receiving entity.

Conforming SEC and FASB Guidance

In a related development, the SEC has rescinded SAB Topic 5.J, which contained the SEC staff's views on how an SEC registrant should apply pushdown accounting. Thus, all entities — regardless of whether they are SEC registrants — will now apply the guidance in ASU 2014-17.

In May 2015, the FASB issued [ASU 2015-08](#), which removes references to the SEC's SAB Topic 5.J on pushdown accounting from ASC 805-50. The SEC's SAB 115 had superseded the guidance in SAB Topic 5.J in connection with the FASB's November 2014 release of ASU 2014-17. The amendments in ASU 2015-08 therefore conform the FASB's guidance on pushdown accounting with the SEC's.

Effective Date

The guidance in ASU 2014-17 became effective on November 14, 2014. As of the effective date, an acquired entity would be permitted to elect to apply pushdown accounting arising as a result of change-in-control events occurring before the standard's effective date as long as (1) the change-in-control event is the most recent change-in-control event for the acquired entity and (2) the election is preferable. Entities would not be permitted to unwind a previous application of pushdown accounting (i.e., an acquired entity can change its election for the most recent change-in-control transaction or event from not applying pushdown accounting to applying pushdown accounting, if preferable, but not vice versa).

For more information about ASU 2014-17, see Deloitte's September 2014 [EITF Snapshot](#).

Financial Instruments — Recognition and Measurement

Background

On January 5, 2016, the FASB issued [ASU 2016-01](#), which amends the Board's guidance on the recognition and measurement of financial instruments. During deliberations of the FASB's February 2013 [proposed ASU](#) (which outlined a new model that was largely converged with the IASB's for the classification and measurement of financial instruments), the Board had decided to abandon the converged approach and retain much of the existing requirements in U.S. GAAP. However, the amendments in the final ASU contain significant changes related to:

- Accounting for equity investments (apart from those that are accounted for under the equity method or those that are consolidated).
- Impairment of equity investments measured in accordance with a practicability exception.
- Recognition of changes in fair value attributable to changes in instrument-specific credit risk for financial liabilities for which the fair value option has been elected.
- Disclosure requirements for financial assets and financial liabilities.

For PBEs, the new standard will be effective for fiscal years beginning after December 15, 2017, including interim periods therein. For all other entities, it will be effective for fiscal years beginning after December 15, 2018, and interim periods for the following year. Early adoption of certain of the standard's provisions is permitted for all entities for financial statements that have not yet been issued, provided that the provisions are adopted as of the beginning of the fiscal year of adoption. Non-PBEs would be permitted to adopt the standard in accordance with the effective date for PBEs.

For more information about the final ASU and its potential impact, refer to Deloitte's January 12, 2016, [Heads Up](#).

Classification and Measurement of Equity Investments

The amendments in ASU 2016-01 require entities to carry all investments in equity securities at fair value, with changes in fair value recorded through earnings, unless the equity investments are accounted for under the equity method or are consolidated. For equity investments that do not have a readily determinable fair value, the guidance permits a practicability exception under which the equity investment would be measured at cost less impairment, if any, plus or minus observable price changes in orderly transactions. This exception is not available to reporting entities that are investment companies or broker-dealers in securities.

Impairment Assessment of Equity Investments

The amendments eliminate the requirement for an entity that has elected the practicability exception to assess whether the equity investment is other-than-temporarily impaired. Instead, as of each reporting period, the entity would qualitatively consider the following indicators (from ASC 321-10-35-3, as added by the ASU) to determine whether the investment is impaired:

- a. A significant deterioration in the earnings performance, credit rating, asset quality, or business prospects of the investee
- b. A significant adverse change in the regulatory, economic, or technological environment of the investee
- c. A significant adverse change in the general market condition of either the geographical area or the industry in which the investee operates
- d. A bona fide offer to purchase, an offer by the investee to sell, or a completed auction process for the same or similar investment for an amount less than the carrying amount of that investment
- e. Factors that raise significant concerns about the investee's ability to continue as a going concern, such as negative cash flows from operations, working capital deficiencies, or noncompliance with statutory capital requirements or debt covenants.

If, on the basis of the qualitative assessment, the equity investment is impaired, the investee would be required to record an impairment equal to the amount by which the carrying value exceeds fair value. The investee would no longer be required to evaluate whether such impairment was other than temporary.

Thinking It Through

Under current U.S. GAAP, marketable equity securities that are not accounted for as equity-method investments are classified as either held for trading (with changes in fair value recognized in earnings) or available for sale (AFS) (with changes in fair value recognized in other comprehensive income (OCI)). Investments in nonmarketable equity securities that are not accounted for as equity-method investments are measured at cost (less other-than-temporary impairment). The amendments eliminate the AFS classification category for marketable equity securities as well as the cost method of accounting for qualifying nonmarketable equity securities. As a result of these changes, entities with large portfolios of cost-method investments or equity investments classified as AFS could experience volatility in earnings.

Changes in Fair Value of a Liability Attributed to Changes in Instrument-Specific Credit Risk

For financial liabilities (excluding derivative instruments) for which the fair value option has been elected, the amendments require an entity to separately recognize in OCI any changes in fair value associated with instrument-specific credit risk. This requirement is one of the provisions noted above that may be early adopted. The guidance indicates that the portion of the total change in fair value that exceeds the amount resulting from a change in a base market risk (such as a risk-free interest rate) may be attributable to instrument-specific credit risk; however, the guidance also acknowledges that there may be other methods an entity can use to determine instrument-specific credit risk.

Changes to Disclosure Requirements

For non-PBEs, the amendments eliminate the requirement to disclose the fair value of financial instruments measured at amortized cost. The removal of this requirement is one of the provisions noted above that may be early adopted. In addition, for such financial instruments, PBEs will not be required to disclose (1) the information related to the methods and significant assumptions used to estimate fair value or (2) a description of the changes in the methods and significant assumptions used to estimate fair value. The guidance also clarifies U.S. GAAP by eliminating the provisions in ASC 825 that had been interpreted to permit an “entry” price notion for estimating the fair value of loans for disclosure purposes. The amendments require a PBE to disclose the fair value in accordance with the exit price notion in ASC 820. In addition, all entities are required to disclose in the notes to the financial statements all financial assets and financial liabilities grouped by (1) measurement category (i.e., amortized cost or fair value — net income or OCI) and (2) form of financial asset (i.e., securities and loans/receivables).

Financial Instruments — Impairment

Background

The FASB spent much of 2015 drafting its final guidance on impairment. It also formed a TRG on impairment, comprising financial statement preparers, auditors, and regulators. FASB board members attend the TRG’s meetings, and representatives from the SEC and PCAOB are also invited to observe.

The objective of the impairment TRG is to help the FASB resolve issues related to implementation of the standard both before and after the new guidance is issued. At a private session with the TRG, the FASB recently sought feedback on a staff draft of the final guidance. It is unclear whether the FASB will seek additional feedback from the TRG at other such sessions before the standard is issued.

Project Overview

The amendments will introduce the current expected credit loss (CECL) model, which is a new impairment model² based on expected losses rather than incurred losses. Under the CECL model, an entity would recognize as an allowance its estimate of the contractual cash flows not *expected* to be collected. The FASB believes that the CECL model will result in more timely recognition of credit losses and will reduce the complexity of U.S. GAAP by decreasing the number of credit impairment models used to account for debt instruments.³

Under the existing impairment models (often referred to as incurred loss models), an impairment allowance is recognized only after a loss event (e.g., default) has occurred or its occurrence is probable. In assessing whether to recognize an impairment allowance, an entity may only consider current conditions and past events; it may not consider forward-looking information.



² Although impairment began as a joint FASB and IASB project, constituent feedback on the boards’ “dual-measurement” approach led the FASB to develop its own impairment model. The IASB, however, continued to develop the dual-measurement approach and issued final impairment guidance based on it as part of the July 2014 amendments to IFRS 9. For more information about the IASB’s impairment model, see Deloitte’s August 8, 2014, [Heads Up](#).

³ Note that the proposed CECL model would replace or amend several existing U.S. GAAP impairment models. See Appendix B of Deloitte’s March 13, 2015, [Heads Up](#) for a tabular summary of those models.

The CECL Model

Scope

This proposed guidance is relevant to financial assets but not to property, plant, and equipment. The CECL model will apply to most⁴ debt instruments (other than those measured at fair value through net income (FVTNI)), trade receivables, lease receivables, reinsurance receivables that result from insurance transactions, financial guarantee contracts,⁵ and loan commitments. However, AFS debt securities will be excluded from the model's scope and will continue to be assessed for impairment under ASC 320 (the FASB has proposed limited changes to the impairment model for AFS debt securities, as discussed [below](#)).

Recognition of Expected Credit Losses

Unlike the incurred loss models in existing U.S. GAAP, the CECL model does not specify a threshold for the recognition of an impairment allowance. Rather, an entity will recognize an impairment allowance equal to the current estimate of expected credit losses (i.e., all contractual cash flows that the entity does not expect to collect) for financial assets as of the end of the reporting period. Credit impairment will be recognized as an allowance — or contra-asset — rather than as a direct write-down of the amortized cost basis of a financial asset.

Thinking It Through

Because the CECL model does not have a minimum threshold for recognition of impairment losses, entities will need to measure expected credit losses on assets that have a low risk of loss (e.g., investment-grade held-to-maturity (HTM) debt securities). However, an "entity would not be required to recognize a loss on a financial asset in which the risk of nonpayment is greater than zero [but] the amount of loss would be zero."⁶ U.S. Treasury securities and certain highly rated debt securities may be assets the FASB contemplated when it allowed an entity to recognize zero credit losses on an asset, but the Board decided not to specify the exact types of assets. Nevertheless, the requirement to measure expected credit losses on financial assets whose risk of loss is low is likely to result in additional costs and complexity.

Measurement of Expected Credit Losses

Under the amendments, an entity's estimate of expected credit losses represents all contractual cash flows that the entity does not expect to collect over the contractual life of the financial asset. When determining the contractual life of a financial asset, the entity would consider expected prepayments but would not be allowed to consider expected extensions unless it "reasonably expects that it will execute a troubled debt restructuring with the borrower."⁷

The entity would consider all available relevant information in making the estimate, including information about past events, current conditions, and reasonable and supportable forecasts and their implications for expected credit losses. That is, while the entity would be able to use historical charge-off rates as a starting point in determining expected credit losses, it would have to evaluate how conditions that existed during the historical charge-off period differ from its current expectations and accordingly revise its estimate of expected credit losses. However, the entity would not be required to forecast conditions over the contractual life of the asset. Rather, for the period beyond the period for which the entity can make reasonable and supportable forecasts, the entity would revert to an unadjusted historical credit loss experience.

⁴ The CECL model would not apply to the following debt instruments:

- Loans made to participants by defined contribution employee benefit plans.
- Policy loan receivables of an insurance entity.
- Pledge receivables (promises to give) of a not-for-profit entity.
- Loans and receivables between entities under common control.

⁵ The CECL model would not apply to financial guarantee contracts that are accounted for as insurance or measured at FVTNI.

⁶ Quoted text is from the FASB's [summary](#) of tentative Board decisions reached at the joint meeting of the FASB and IASB on September 17, 2013.

⁷ Quoted text is from the FASB's [summary](#) of tentative Board decisions reached at its September 3, 2014, meeting.

Thinking It Through

Measuring expected credit losses will most likely be a significant challenge for all entities. Entities may also incur one-time or recurring costs associated with implementing the CECL model, such as those related to system changes, data collection, and using forward-looking information to estimate expected credit losses over the contractual life of an asset.

Unit of Account

The CECL model does not prescribe a unit of account (e.g., an individual asset or a group of financial assets) in the measurement of expected credit losses. However, an entity would be required to evaluate financial assets within the scope of the model on a collective (i.e., pool) basis when similar risk characteristics are shared. If a financial asset does not share similar risk characteristics with the entity's other financial assets, the entity would evaluate the financial asset individually. If the financial asset is individually evaluated for expected credit losses, the entity would not be allowed to ignore available external information such as credit ratings and other credit loss statistics.

Thinking It Through

Under the new guidance, an entity will be required to collectively measure expected credit losses on financial assets that share similar risk characteristics (including HTM securities). While the concept of pooling and collective evaluation currently exists in U.S. GAAP for certain loans, the FASB has not specifically defined "similar risk characteristics." As a result, it remains to be seen whether the FASB expects an aggregation based on "similar risk characteristics" to be consistent with the existing practice of pooling purchased credit-impaired (PCI) assets on the basis of "common risk characteristics." Entities may need to make changes to systems and processes to capture loss data at more granular levels depending on the expectations of market participants such as standard setters, regulators, and auditors.

AFS Debt Securities

The impairment of AFS debt securities will continue to be accounted for under ASC 320. However, the amendments revise that guidance by:

- Limiting the credit losses recognized to the difference between the security's amortized cost and its fair value.
- Requiring an entity to use an allowance approach (vs. permanently writing down the security's cost basis).
- Removing the requirement that an entity must consider the length of time fair value has been less than amortized cost when assessing whether a security is other-than-temporarily impaired.
- Removing the requirement that an entity must consider recoveries in fair value after the balance sheet date when assessing whether a credit loss exists.

Thinking It Through

The Board did not revise (1) step 1 of the existing other-than-temporary impairment model (i.e., an “investment is impaired if the fair value of the investment is less than its cost”) or (2) the requirement under ASC 320 that entities recognize the impairment amount only related to credit in net income and the noncredit impairment amount in OCI. However, entities would use an allowance approach when recognizing credit losses (as opposed to a permanent write-down of the AFS security’s cost basis). As a result, in both of the following instances, an entity would reverse credit losses through current-period earnings on an AFS debt security:

- If the fair value of the debt security exceeds its amortized cost in a period after a credit loss had been recognized through earnings (because fair value was less than amortized cost), the entity would reverse the *entire* credit loss previously recognized and recognize a corresponding adjustment to its allowance for credit losses.
- If the fair value of the debt security does not exceed its amortized cost in a period after a credit loss had been recognized through earnings (because fair value was less than amortized cost) but the credit quality of the debt security improves in the current period, the entity would reverse the credit loss previously recognized only in an amount that would reflect the improved credit quality of the debt security.

These revisions to the impairment model in ASC 320 could result in earlier recognition of impairment.

PCI Assets

PCI assets are acquired financial assets for which there has been a “more than insignificant” deterioration in credit quality since origination. An entity will measure expected credit losses for these assets the same way it measures expected credit losses for originated and purchased non-credit-impaired assets.

Upon acquiring a PCI asset, the entity would recognize as its allowance for expected credit losses the amount of contractual cash flows not expected to be collected as an adjustment that increases the cost basis of the asset (the “gross-up” approach). After initial recognition of the PCI asset and its related allowance, the entity would continue to apply the CECL model to the asset — that is, any changes in the entity’s estimate of cash flows that it expects to collect (favorable or unfavorable) would be recognized immediately in the income statement. Consequently, any subsequent changes to the entity’s estimate of expected credit losses — whether unfavorable or favorable — would be recorded as impairment expense (or reduction of expense) during the period of change. Interest income recognition would be based on the purchase price plus the initial allowance accreting to the contractual cash flows.



Thinking It Through

Under the current accounting for PCI assets, an entity recognizes unfavorable changes in cash flows as an immediate credit impairment but treats favorable changes in cash flows that are in excess of the allowance as prospective yield adjustments. The CECL model's approach to PCI assets eliminates this asymmetrical treatment in cash flow changes. However, in a manner consistent with current practice, the CECL model precludes an entity from recognizing as interest income the discount embedded in the purchase price that is attributable to expected credit losses as of the date of acquisition.

An acquired asset is currently considered credit-impaired when it is probable that the investor would be unable to collect all contractual cash flows as a result of deterioration in the asset's credit quality since origination. However, as noted above, under the FASB's tentative approach, a PCI asset is an acquired asset for which there has been a "more than insignificant" deterioration in credit quality since origination. The FASB revised the definition of a PCI asset partially in response to stakeholder feedback suggesting that if an entity were to recognize expected credit losses in its income statement upon purchase of any asset, regardless of the level of credit deterioration in the asset's credit quality since origination, the entity would be "double-counting" expected credit losses on that asset because those losses were already contemplated in the purchase price. Although the FASB decided not to require an entity to apply the gross-up approach to all acquired assets, stakeholders are likely to support the change to the definition of a PCI asset because an entity is likely to apply the gross-up approach to more assets than it would have under the requirements in the proposed amendments. The FASB has also indicated that the final standard will include implementation guidance to help entities assess whether there has been a "more than insignificant" deterioration in a purchased asset's credit quality since origination.

Disclosures

Many of the disclosures required under the amendments are similar to those already required under U.S. GAAP as a result of [ASU 2010-20](#). Accordingly, entities will need to disclose information related to:

- Credit quality.⁸
- Allowance for expected credit losses.
- Policy for determining write-offs.
- Past-due status.
- PCI assets.
- Collateralized financial assets.

In addition, an entity will need to disclose credit-quality indicators for each asset class, disaggregated by vintage, for a period not to exceed five years (although upon transition, the entity will be required to provide this disclosure only for the current and prior-year amortized cost balances). The disclosure will be required for annual and interim periods and would not be required for an entity's revolving lines of credit.

Transition

For most debt instruments, the amendments will require entities to record a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective (modified retrospective approach). However, instrument-specific transition provisions are provided for other-than-temporarily impaired debt securities, PCI assets, and certain beneficial interests within the scope of ASC 325-40.

⁸ Short-term trade receivables resulting from revenue transactions within the scope of ASC 605 are excluded from these disclosure requirements.

Other Significant Decisions

The new guidance will also reflect the FASB's tentative decisions related to the following:

- Practical expedients when measuring expected credit losses.
- Write-offs.
- Modifications.
- Certain beneficial interests within the scope of ASC 325-40.
- Loan commitments.
- Transition disclosures.

Effective Date and Early Adoption

The Board tentatively decided the following:

- For PBEs that meet the definition under U.S. GAAP of an SEC filer, the final standard will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.
- For PBEs that do not meet the definition of an SEC filer, the final standard will be effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years.
- For all other entities, the final standard will be effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years beginning after December 15, 2020.

The Board also tentatively decided that PBEs that meet the definition under U.S. GAAP of an SEC filer will not be permitted to early adopt the final standard. All other entities will be permitted to early adopt the final standard, but not before an SEC filer would adopt the standard.

Next Steps

The FASB expects to issue a final standard in the first quarter of 2016. For a comprehensive summary of the impairment project to date, see the [project update page](#) on the FASB's Web site.

Thinking It Through

Reporting entities currently use various methods to estimate credit losses. Some apply simple approaches that take into account average historical loss experience over a fixed time horizon. Others use more sophisticated "migration" analyses and forecast modeling techniques. Under the CECL model, for any approach that is based solely on historical loss experience, an entity would need to consider the effect of forward-looking information over the remaining contractual life of a financial asset. In addition, when an entity is "developing its estimate of expected credit losses . . . for periods beyond which the entity is able to make or obtain reasonable and supportable forecasts, [the] entity is allowed to revert to its [unadjusted] historical credit loss experience."⁹

For instance, assume that an entity uses annualized loss rates to determine the amount of probable unconfirmed losses on its homogeneous pools of loans as of the reporting date. When moving to the CECL model, the entity may need to revise its allowance method by adjusting the fixed time horizon (i.e., annualized loss rates) to equal a period that represents the full contractual life of the instrument. Entities using a probability-of-default (PD) approach may need to revise their PD and loss-given-default (LGD) statistics to incorporate the notion of lifetime expected losses. Today, an entity's PD approach might be an estimate of the probability that default will occur over a fixed assessment horizon, which is less than the full contractual life of the instrument (often one year). Similarly, an entity would need to revise its LGD statistic to incorporate the notion of lifetime expected losses (i.e., the percentage of loss over the total exposure if default were to occur during the full contractual life of the instrument).

⁹ Quoted text is from the FASB's [summary](#) of tentative Board decisions reached at its August 13, 2014, meeting.

Financial Instruments — Hedging

Background

As part of its project on targeted improvements to hedge accounting, the FASB held several educational sessions during 2015. Those sessions have thus far culminated in two decision-making meetings at which the FASB made a number of tentative decisions that, if ultimately adopted, would significantly modify certain aspects of the existing hedge accounting model. The Board hopes to issue a proposed ASU reflecting these tentative conclusions in the second quarter of 2016.

Overall Hedging Model

The FASB tentatively decided to retain, for both fair value and cash flow hedges, (1) the highly effective threshold used to qualify for hedge accounting under current U.S. GAAP and (2) the current guidance allowing an entity to voluntarily dedesignate a hedging relationship. Further, under the proposal, an entity would still need specified documentation in place at hedge inception, including a description of its method for quantitatively assessing hedge effectiveness (unless the criteria for using the shortcut or critical-terms-match methods are met, obviating the need for quantitative assessments). However, an entity would not have to actually complete that initial quantitative assessment of hedge effectiveness until the end of the reporting period in which it designated the hedge (i.e., an entity could have up to three months to complete the initial quantitative assessment of effectiveness). Also under the proposal, after hedge inception, an entity would need to perform quantitative assessments of hedge effectiveness only when facts and circumstances change.

The Board also tentatively decided to eliminate the traditional concept of hedge ineffectiveness:

- For highly effective cash flow hedging relationships, the entire change in the fair value of the hedging instrument included in an entity's hedge effectiveness assessment would initially be recorded in OCI. When the hedged item affects earnings, the amount in accumulated OCI would be reclassified to the same income statement line as the earnings effect of the hedged item. Any portion of the change in the fair value of the hedging instrument that is excluded from an entity's hedge effectiveness assessment would be recognized immediately in earnings (but presented on the same income statement line as the earnings effect of the hedged item).
- For highly effective fair value hedging relationships, the entire change in the fair value of the hedging instrument would be recorded in earnings immediately in the same income statement line as the hedged item.
- For highly effective net investment hedging relationships, the entire change in the fair value of the hedging instrument included in an entity's hedge effectiveness assessment would initially be recorded as part of the cumulative-translation adjustment in OCI. When the hedged item affects earnings, the amount in accumulated OCI would be reclassified to the same income statement line as the earnings effect of the hedged item. Any portion of the change in the fair value of the hedging instrument that is excluded from an entity's hedge effectiveness assessment would be recognized immediately in earnings.

In addition, the FASB tentatively decided to require additional disclosure about (1) cumulative-basis adjustments for fair value hedges and (2) the effect of hedging on individual income statement line items. It also tentatively decided to require expanded qualitative disclosures about the quantitative goals, if any, that an entity set to achieve its hedging objectives.

Nonfinancial Hedging Relationships

For hedges of nonfinancial items, the Board tentatively decided to change existing GAAP to permit an entity to designate as a hedged item a contractually specified component or ingredient that is linked to a contractually stated rate or index. Any cap, floor, or negative basis that is related to the pricing of a contractually specified component of a nonfinancial item would not preclude designation of that component as a hedged item — an entity would just need to consider such pricing features in its assessment of hedge effectiveness.

Thinking It Through

The FASB's tentative decision to permit entities to hedge risks from contractually specified components of nonfinancial items represents a significant change from existing U.S. GAAP and may especially affect O&G entities. For example, under the proposed guidance, an O&G entity with a commodity exposure at a given delivery point may be able to hedge only the price risk associated with price volatility at a liquid trading hub instead of the entire exposure from the contract.

Financial Hedging Relationships

For hedges of financial items, the FASB tentatively decided to (1) allow the contractually specified index rate in a variable-rate hedged item to be the designated interest rate risk (thereby relieving entities of the need to designate a benchmark interest rate for cash flow hedges of variable-rate instruments); (2) retain the existing benchmark interest rate definition for hedges of fixed-rate instruments, with minor modifications to eliminate inconsistencies; and (3) designate the Securities Industry and Financial Markets Association (SIFMA) Municipal Swap index as a permitted benchmark interest rate.

In addition, the tentative decisions would allow an entity, for fair value hedges of interest rate risk, to:

- Consider only the effects of the designated hedged risk (e.g., interest rate risk) on a prepayment option when determining the change in the value of the debt for hedges of callable debt.
- Designate as the hedged risk only a portion of the hedged item's term (i.e., compute the change in the hedged item's fair value by using the same term as that of the hedging instrument).
- Calculate the change in the fair value of the hedged item attributable to changes in the benchmark interest rate by using either (1) total coupon cash flows or (2) only those cash flows related to the benchmark interest rate. However, an entity would be required to use total coupon cash flows when the effective interest rate of the hedged item is less than the benchmark interest rate on the date of hedge designation.

Shortcut Method

The FASB tentatively decided to retain the shortcut method in current U.S. GAAP. However, the Board also tentatively decided to allow an entity to document at hedge inception the long-haul method it would use to measure hedge ineffectiveness if the shortcut method could not be applied. That is, if the entity later determines that continued use of the shortcut method is inappropriate, it can continue the hedging relationship by using the long-haul method designated at inception as long as the hedging relationship has been highly effective since inception.

Next Steps

The FASB staff will (1) continue deliberations, including consideration of whether alternative hedge documentation requirements for private companies are warranted; (2) develop a staff draft reflecting the Board's decisions; (3) analyze the costs, benefits, and potential complexity of the tentative decisions; and (4) identify any issues that need to be brought back to the Board for a vote. In addition, the FASB will need to address transition and the comment period of the proposed ASU.

Thinking It Through

When the proposal is issued, O&G entities should carefully analyze it to assess its possible ramifications on their hedging strategies, systems, and internal controls, and they are encouraged to provide feedback on the proposed amendments to the FASB. Multinational companies should note that the FASB's proposed hedging model is likely to differ significantly from the IASB's IFRS 9 hedging model.

To follow the status of the FASB's hedging project, see the [project page](#) on Deloitte's US GAAP Plus Web site.

Liabilities and Equity — Targeted Improvements

Background

In November 2014, the FASB added to its agenda a project to “simplify the accounting guidance related to financial instruments with characteristics of liabilities and equity.”¹⁰ The project focuses on the following:

1. Application of the indexation guidance in ASC 815-40 to “equity-linked financial instruments containing ‘down round’ features.”
2. The indefinite deferral of the liability classification guidance in ASC 480-10 on certain “mandatorily redeemable financial instruments for certain nonpublic entities and certain mandatorily redeemable noncontrolling interests.”
3. Potential improvements to the accounting guidance in ASC 815-40 on “[f]reestanding contracts indexed to, and potentially settled in, an entity’s own stock.”
4. “Improving the navigation within the Codification.”

Deliberations on the first phase of this project began at the FASB’s September 6, 2015, meeting, during which the Board discussed items (1) and (2) above.

Down-Round Features

At its September 2015 meeting, the Board tentatively decided to create a new accounting model that would replace the existing guidance on such features in ASC 815-40.

Thinking It Through

A down-round feature is a provision in an equity-linked financial instrument (e.g., a freestanding warrant contract or an equity conversion feature embedded within a host debt or equity contract) that triggers a downward adjustment to the instrument’s strike price (or conversion price) if the entity issues equity shares at a lower price (or equity-linked financial instruments with a lower strike price) than the instrument’s strike price. The purpose of the feature is to protect the instrument’s counterparty from future issuances of equity shares at a more favorable price. For example, a warrant may specify that the strike price is the lower of \$5 per share or the common stock offering price in any future initial public offering of the shares. Under current U.S. GAAP, a contract that contains a down-round feature does not qualify as equity because it precludes a conclusion that the contract is indexed to the entity’s own stock under ASC 815-40-15 (as illustrated in ASC 815-40-55-33 and 55-34).

Unlike current U.S. GAAP, the Board’s tentative approach related to down-round features would not preclude an entity from concluding that an instrument is indexed to the entity’s own stock. For example, when an entity evaluates whether it is required to classify a freestanding warrant to acquire the entity’s common stock as a liability under ASC 815-40, the existence of the down-round feature would not affect the analysis. Similarly, a down-round feature would be excluded from the analysis of whether (1) an embedded conversion feature in a debt host contract must be bifurcated as an embedded derivative under ASC 815-15 or (2) it qualifies for the derivative accounting scope exception in ASC 815-10-15-74 for contracts indexed to an entity’s own stock and classified in stockholders’ equity.

Under the tentative approach, if a down-round feature is triggered, the accounting for it would be aligned with the classification of the related instrument. For an equity-classified instrument, the transfer of value from the entity to the holder at the time the down-round feature is triggered would result in the recognition of a dividend to the investor. If the instrument is classified as a liability, the transfer of value resulting from the down-round feature when triggered would be recognized through a charge to earnings. If the entire instrument is classified as a liability with changes in fair value charged

¹⁰ Quoted text is from the [project update page](#) on the FASB’s Web site.

to earnings each reporting period, no separate adjustment would be required since the value of the down-round when triggered would inherently be captured in the periodic adjustment.

The FASB believes that existing U.S. GAAP requirements sufficiently address disclosures related to instruments with down-round features. However, the Board supported the addition of a narrow requirement for entities to disclose, in the period the down-round feature is triggered, the impact of recognizing the feature.

Thinking It Through

Under current U.S. GAAP, the existence of a down-round feature automatically precludes the instrument being evaluated (whether freestanding or embedded) from meeting the derivative accounting scope exception in ASC 815-40-15-74. As a result of the tentative approach, there would be (1) more freestanding contracts on own equity (e.g., warrants) that meet this scope exception (and thus more contracts being included within equity rather than accounted for as derivative liabilities) and (2) fewer embedded features (e.g., equity conversation features) that meet all the criteria in ASC 815-15 for bifurcation as embedded derivatives. This will reduce earnings volatility in the issuer's financial statements since derivatives liabilities — unlike equity-classified contracts — are adjusted to their fair value each reporting period.

Indefinite Deferrals Under ASC 480-10

The transition guidance in ASC 480-10 indefinitely defers the application of some of its requirements to certain instruments and entities (i.e., certain mandatorily redeemable financial instruments of nonpublic entities that are not SEC registrants and certain mandatorily redeemable noncontrolling interests). Accordingly, such instruments may qualify as equity under U.S. GAAP even though ASC 480-10-25 suggests that they should be classified as liabilities. The Board tentatively agreed to replace the indefinite deferrals in ASC 480-10 with scope exceptions that have the same applicability. This is not intended to have any impact on accounting treatment but rather to improve navigation within the Codification.

Next Steps

The Board has directed its staff to proceed with drafting a proposed ASU for a vote by written ballot. The proposed ASU will have a comment period of at least 60 days.

Accounting for Goodwill for Public Business Entities and Not-for-Profit Entities

Background

In November 2013, the FASB endorsed a decision by the PCC to allow non-PBEs to amortize goodwill and perform a simplified impairment test. The Board received feedback on the PCC's decision indicating that many PBEs and not-for-profit entities had similar concerns about the cost and complexity of the annual goodwill impairment test. In response, the Board added this project to its agenda in 2014.

Current Status and Next Steps

The project is currently in the initial deliberations phase. At its meeting on October 28, 2015, the FASB tentatively decided to split the project into two phases. The first phase would focus on simplifying the goodwill impairment test. In the second phase, the Board would work with the IASB to address stakeholder concerns related to the subsequent accounting for goodwill.

At the October meeting, the Board discussed how to simplify the goodwill impairment test and tentatively decided to remove step 2, thus eliminating the requirement to complete a hypothetical purchase-price allocation. The FASB also tentatively decided not to give entities the option to perform step 2 and to instead require them to adopt the simplified impairment test prospectively. An ED related to the first phase of the project is expected to be released in the first half of 2016 with a 60-day comment period.

Clarifying the Definition of a Business

Background

In November 2015, the FASB issued a [proposed ASU](#) that would clarify the definition of a business in ASC 805 and provide a framework that an entity can use to determine whether a set of activities and assets (collectively, a “set”) constitutes a business. The FASB issued the proposed ASU in response to stakeholder feedback indicating that the definition of a business in ASC 805 is too broad and that too many transactions are qualifying as business combinations even though many of these transactions may more closely resemble asset acquisitions.

Key Provisions of the Proposed ASU

The definition of a business would remain unchanged under the proposed ASU. However, the proposed ASU’s Basis for Conclusions indicates that the amendments would “narrow the definition of a business and provide a framework that gives entities a basis for making reasonable judgements about whether a transaction involves an asset or a business.” In addition, the proposal provides examples illustrating the application of the amendments to the determination of whether a set is a business.

Other key provisions of the proposed ASU would:

- “[P]rovide a practical way to determine when a [set] is not a business.” That is, “when substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets,” the set would not be considered a business. When this threshold is met, an entity would not need to evaluate the rest of the implementation guidance.
- Clarify that to be “a business, a transaction must include, at minimum, an input and a substantive process.”
- Provide two different sets of criteria for entities to consider in determining whether a set has a substantive process; these criteria depend on whether a set has outputs.
- Change the definition of outputs to “[t]he result of inputs and processes applied to those inputs that provide goods or services to customers, other revenues, or investment income, such as dividends or interest.”
- “[R]emove the requirement that a set is a business if market participants can replace the missing elements and continue to produce outputs.”

Convergence With IFRSs

The definition of a business in ASC 805 is currently identical to that in IFRS 3. However, the interpretation and application of the guidance in jurisdictions that apply U.S. GAAP do not appear consistent with those in jurisdictions that apply IFRSs (i.e., the definition of a business in IFRS jurisdictions is not applied as broadly). Although the proposed ASU would add implementation guidance to U.S. GAAP that is not found in IFRSs, the FASB intends to more closely align practice under U.S. GAAP with that under IFRSs by narrowing application of the U.S. GAAP definition. Further, the IASB has added a project on the definition of a business to its agenda and is considering making amendments similar to those in the proposed ASU.

Next Steps

Comments on the proposed ASU were due by January 22, 2016. An entity would apply the proposed amendments prospectively to any transaction that occurs on or after the effective date and would not be required to provide any disclosures at transition. The proposal notes that the FASB “will determine the effective date and whether the proposed amendments may be applied before the effective date after it considers stakeholder feedback on the proposed amendments.”

In addition, the Board has begun deliberations on the second phase of this project, which is intended to clarify whether transactions involving in-substance nonfinancial assets (either held directly or in a subsidiary) should be accounted for as acquisitions (or disposals) of nonfinancial assets or as acquisitions (or disposals) of businesses. The project is also intended to clarify the guidance on partial sales or transfers of assets that are within the scope of ASC 610-20 as well as the corresponding acquisition of partial interests in a nonfinancial asset or assets.

Thinking It Through

Both the current and proposed implementation guidance in ASC 805-10-55-4 state that a “business consists of inputs and processes applied to those inputs that have the ability to create outputs.” All businesses have inputs and processes, and most have outputs, but outputs are not required for a set to be a business. Further, ASC 805-10-55-5 states that “all of the inputs or processes that the seller used” in operating the set do not need to be part of the transaction. However, under the proposed ASU, “to be considered a business, the set must include, at a minimum, an input and a substantive process that together contribute to the ability to create outputs.” This is a change from the current guidance, under which a set meets the definition of a business if “market participants are capable of acquiring the [set] and continuing to produce outputs, for example, by integrating the [acquired set] with their own inputs and processes.”

Under the current guidance, the following are common types of business acquisitions within the O&G industry:

- Acquisition of a working interest in proved reserves (regardless of whether the working interest is in a producing property).
- Acquisition, in certain circumstances, of net profit interest and royalty interest in proved reserves.
- Acquisition of an entity that generates cash flows to provide a return on investment.

O&G entities should continue to monitor proposed amendments to the definition of a business and their potential effects on the industry.

For additional information about the proposed ASU, see Deloitte’s December 4, 2015, [Heads Up](#).

Classification of Certain Cash Receipts and Cash Payments in the Statement of Cash Flows

To reduce diversity in practice in the application of ASC 230, the FASB added the following nine issues related to the classification of cash flows to the EITF’s agenda in 2015 (addressed as part of EITF Issue No. 15-F):

- “Issue 1 — Debt Prepayment or Debt Extinguishment Costs.”
- “Issue 2 — Settlement of Zero-Coupon Bonds.”
- “Issue 3 — Contingent Consideration Payments Made After a Business Combination.”
- “Issue 4 — Proceeds From the Settlement of Insurance Claims.”

- “Issue 5 — Proceeds from the Settlement of Corporate-Owned Life Insurance Policies, Including Bank-Owned Life Insurance Policies.”
- “Issue 6 — Distributions Received From Equity Method Investees.”
- “Issue 7 — Beneficial Interests in Securitization Transactions.”
- “Issue 8 — Predominant Cash Receipts and Cash Payments.”
- “Issue 9 — Restricted Cash.”

At its November 2015 meeting, the EITF reached a consensus-for-exposure on eight of the issues (i.e., all issues except restricted cash). On January 29, 2016, the FASB issued a [proposed ASU](#) that would ratify the decisions reached by the EITF on those eight issues. Entities would be required to apply the proposed ASU retrospectively to all prior periods presented unless it is impracticable to do so, in which case they would apply the guidance prospectively as of the earliest date practicable. After considering stakeholder feedback, the FASB will determine the effective date of the proposed guidance and whether to permit early adoption.

In addition, the EITF continued redeliberating restricted cash (Issue 9), including issues related to the (1) definition of restricted cash, (2) classification of changes in restricted cash, and (3) presentation of cash payments and receipts that directly affect restricted cash. The EITF tentatively decided that changes in restricted cash would be classified as investing activities. At its March 2016 meeting, the EITF will continue to deliberate the issues related to restricted cash.

Disclosure Framework

Background

In July 2012, the FASB issued a [discussion paper](#) as part of its project to develop a framework to make financial statement disclosures “more effective, coordinated, and less redundant.” The paper identifies aspects of the notes to the financial statements that need improvement and explores possible ways to improve them. The FASB subsequently decided to distinguish between the “Board’s decision process” and the “entity’s decision process” for evaluating disclosure requirements.

FASB’s Decision Process

In March 2014, the FASB released for public comment a [proposed concepts statement](#) that would add a new chapter to the Board’s conceptual framework for financial reporting. The proposal outlines a decision process to be used by the Board and its staff for determining what disclosures should be required in notes to financial statements. The FASB’s objective in issuing the proposal is to improve the effectiveness of such disclosures by ensuring that reporting entities clearly communicate the information that is most important to users of financial statements. See Deloitte’s March 6, 2014, [Heads Up](#) for additional information.

Entity’s Decision Process

In September 2015, the FASB issued a [proposed ASU](#) that would amend the Codification to indicate that the omission of disclosures about immaterial information is not an accounting error. The proposal, which is part of the FASB’s disclosure effectiveness initiative, notes that materiality is a legal concept applied to assess quantitative and qualitative disclosures individually and in the aggregate in the context of the financial statements taken as a whole. See Deloitte’s September 28, 2015, [Heads Up](#) for additional information.

Comments on the proposed ASU were due by December 8, 2015.

Topic-Specific Disclosure Reviews

In addition to proposing amendments to guidance, the FASB staff is analyzing ways to “further promote [entities’] appropriate use of discretion” in determining proper financial statement disclosures. The Board is applying the concepts in both the entity’s and the Board’s decision process in considering “section-specific modifications.” In the second half of 2015, the FASB reached tentative decisions about disclosure requirements in the following Codification topics:

- ASC 820 (fair value measurement).
- ASC 740 (income taxes).
- ASC 715-20 (defined benefit plans).
- ASC 330 (inventory).

Proposed changes to the disclosure requirements for fair value measurement and income taxes are discussed below.

Fair Value Measurement

Objective for Disclosures

On December 3, 2015, the FASB issued for public comment a [proposed ASU](#) that would amend the requirements in ASC 820 for disclosing fair value measurements. The proposed ASU would add the following objective to ASC 820 to encourage preparers to use discretion in complying with the disclosure requirements:

The objective of the disclosure requirements in this Subtopic is to provide users of financial statements with information about all of the following:

- a. The valuation techniques and inputs that a reporting entity uses to arrive at its measures of fair value, including judgments and assumptions that the entity makes
- b. The effects of changes in fair value on the amounts reported in financial statements
- c. The uncertainty in the fair value measurement of Level 3 assets and liabilities as of the reporting date
- d. How fair value measurements change from period to period.

In addition to establishing a disclosure objective, the Board has tentatively decided to make changes (i.e., eliminations, modifications, and additions) to the specific fair value disclosure requirements of ASC 820.

Eliminated and Modified Disclosure Requirements

Policy on Timing of Transfers Between Levels and Transfers Between Levels 1 and 2

The proposed ASU would remove the requirement in ASC 820-10-50-2C for an entity to disclose its policy on the timing of transfers between levels of the fair value hierarchy. An entity would still be required to have a consistent policy on timing of such transfers. The requirement to separately disclose the amounts transferred between Level 1 and Level 2 and the corresponding reason for doing so would also be removed.

Level 3 Fair Value Measurements

The Board made the following tentative decisions that affect disclosures about Level 3 fair value measurements:

- *Valuation process* — Remove requirements in ASC 820-10-50-2(f) (and related implementation guidance in ASC 820-10-55-105) for an entity to disclose its valuation processes for Level 3 fair value measurements.

Thinking It Through

Removing the disclosure requirement in ASC 820-10-50-2(f) will result in divergence between U.S. GAAP and IFRSs. The requirement was added to the FASB's and IASB's jointly issued standard on the basis of a recommendation by the IASB's expert panel. The panel explained that the disclosure would help users understand the quality of the entity's fair value estimates and give investors more confidence in management's estimate. The FASB tentatively decided to remove the requirement because it would conflict with the Board's proposed concepts statement. The Board indicated that disclosure of internal control procedures is outside the purpose of the notes to the financial statements and is not required under other topics in U.S. GAAP.

Removing this requirement does not change management's responsibility for internal controls over the valuation process and related auditor testing. Further, it should not affect investor confidence in the quality of the fair value estimate given the regulatory environment in the United States (e.g., SEC and PCAOB) as well as the intense scrutiny in this area. The Board also noted that investors are typically familiar with the overall valuation process.

- *Measurement uncertainty* — Retain the requirement in ASC 820-10-50-2(g) to provide a narrative description of the sensitivity of the fair value measurement to changes in unobservable inputs. However, the Board plans to clarify that this disclosure is intended to communicate information about the uncertainty in measurement as of the reporting date and not to provide information about sensitivity to future changes in fair value.
- *Quantitative information about unobservable inputs* — Require disclosure of the range and weighted average of the unobservable inputs to comply with the requirement in ASC 820-10-50-2(bbb) (as shown by example in the implementation guidance in ASC 820-10-55-103). Disclosing the period used to develop significant unobservable inputs based on historical data would also be required.
- *Level 3 rollforward* — Retain the Level 3 rollforward requirement for PBEs. For entities that are not PBEs, the Board tentatively decided to modify the Level 3 rollforward guidance and remove the requirement to disclose the change in unrealized appreciation or depreciation related to investments held as of the balance sheet date under ASC 820-10-50-2(d). Instead, disclosures would be required about transfers into and out of Level 3 and purchases of Level 3 investments. The Board indicated that entities are already required to disclose the ending balance in the fair value hierarchy table, and they could disclose transfers into (and out of) and purchases of Level 3 investments in a sentence rather than in a full rollforward as required today. A defined benefit plan sponsor would also remove the reconciliation of beginning and ending balances for plan investments categorized as Level 3 within the fair value hierarchy (i.e., the Level 3 rollforward) and would only be required to disclose transfers into and out of Level 3 and purchases of Level 3 assets in its defined benefit plan footnote (for more information about the FASB's project on reviewing defined benefit plan disclosures, see the [project page](#) on Deloitte's US GAAP Plus Web site).



Thinking It Through

The Board discussed the results of user outreach on the Level 3 rollforward and noted that some financial statement users believe that the rollforward is useful because it helps them understand management's decisions, especially for different economic cycles. The full rollforward was generally deemed less useful for users of private-company financial statements. Transfers into and out of Level 3 were generally considered to be the most useful aspect of the rollforward.

New Disclosure Requirements — Unrealized Gains and Losses

PBEs would disclose fair value changes for assets and liabilities held as of the balance sheet date disaggregated by fair value hierarchy level (i.e., Levels 1, 2, and 3) for (1) net income before taxes and (2) comprehensive income. This is currently only required for the Level 3 amounts within net income under ASC 820-10-50-2(c) and (d). This requirement would not apply to entities that are not PBEs in accordance with the private-company decision-making framework.

Transition and Next Steps

The proposed ASU requires that the modifications to disclosures about changes in unrealized gains and losses and the changes in the quantitative information about unobservable inputs (see discussion above) would be applied prospectively beginning in the period of adoption. Entities would apply all other changes in disclosures retrospectively to all periods presented.

The FASB did not propose an effective date. Rather, the Board indicated that it plans to determine such date after considering stakeholders' feedback on the proposed ASU. Comments on the proposed ASU are due by February 29, 2016.

Income Taxes

At its meeting on January 7, 2015, the FASB staff outlined potential revisions to the disclosure requirements in ASC 740 that would enhance a financial statement user's understanding of foreign taxes. The Board's efforts are largely driven by [findings](#) in the post-implementation review of Statement 109 that users want more information that will allow them to (1) "analyze the cash effects associated with income taxes, particularly current period taxes paid by jurisdiction (e.g., U.S. and foreign), and estimate future tax payments"; and (2) "analyze earnings determined to be indefinitely reinvested in foreign subsidiaries."

At its October 21, 2015, meeting, the FASB discussed income tax disclosure requirements related to income taxes paid, deferred income taxes, valuation allowances, and rate reconciliation and reached the following tentative decisions, which would apply to both public and nonpublic entities:

- *Income taxes paid* — The Board would add requirements for a reporting entity to disclose (1) when a change in tax law has been enacted and it is probable that the change will affect the reporting entity in a future period and (2) the disaggregation of the income taxes paid between foreign and domestic jurisdictions.
- *Deferred income taxes* — An entity would be required to disclose the balance sheet line item(s) in which deferred taxes are presented (i.e., a mapping of total deferred taxes to the balance sheet line items in which they are reported).
- *Valuation allowances* — An entity would need to explain the "nature and amounts of the valuation allowance recorded and released during the reporting period."¹¹
- *Rate reconciliation* — The Board tentatively decided that:
 - Nonpublic entities would be required to present a rate reconciliation in the notes to the financial statements, as ASC 740-10-50-12 currently requires for public entities.
 - A disaggregation of a component of the rate reconciliation would be required if the individual component is greater than or equal to 5 percent of the tax at the statutory rate in a manner consistent with SEC Regulation S-X.
 - An entity would be required to disclose a qualitative description of the items that have caused a significant year-over-year change to the effective tax rate.

In addition, the Board tentatively decided to require disclosures about the (1) gross amounts and expiration dates of carryforwards recorded on a tax return, (2) tax-effected amounts and expiration dates of carryforwards that give rise to a deferred tax asset (DTA), and (3) total amount of unrecognized tax benefits that offset DTAs related to carryforwards.

¹¹ Quoted text is from the FASB's [summary](#) of tentative Board decisions reached at its October 21, 2015, meeting.

The Board directed its staff to begin drafting a proposed ASU for public comment that would take into account all the tentative decisions reached to date regarding income tax disclosure requirements. Such decisions include the Board's previous tentative decisions made about disclosure requirements related to indefinitely reinvested foreign earnings and unrecognized tax benefits.

Undistributed Foreign Earnings

On February 11, 2015, the FASB tentatively decided that entities should:

- Disclose information separately about the domestic and foreign components of income before income taxes. Further, entities should separately disclose income before income taxes of individual countries that are significant relative to total income before income taxes.¹²
- Disclose the domestic tax expense recognized in the period related to foreign earnings.
- Disclose unremitted foreign earnings that, during the current period, are no longer asserted to be indefinitely reinvested and an explanation of the circumstances that caused the entity to no longer assert that the earnings are indefinitely reinvested. These disclosures should be provided in the aggregate and for each country for which the amount no longer asserted to be indefinitely reinvested is significant in relation to the aggregate amount.
- Separately disclose the accumulated amount of indefinitely reinvested foreign earnings for any country that is at least 10 percent of the aggregate amount.

Unrecognized Tax Benefits

At its [meeting](#) on August 26, 2015, the FASB tentatively decided to:

- Add a disclosure requirement in the tabular reconciliation to disaggregate settlements between cash and noncash (e.g., settlement by using existing net operating loss or tax credit carryforwards).
- Add a disclosure requirement to provide a breakdown of the amount of total unrecognized tax benefits shown in the tabular reconciliation by the respective balance-sheet lines on which such unrecognized tax benefits are recorded.
- Eliminate the requirement in ASC 740-10-50-15(d) for entities to provide details of positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease in the next 12 months.

Since the two new proposed disclosure requirements for unrecognized tax benefits are related to the tabular reconciliation, they will only apply to public entities.

The Board directed its staff to prepare examples of the proposed additional disclosures.

Thinking It Through

While some of the FASB's proposed amendments to the current disclosure requirements for fair value measurement and income taxes would eliminate existing requirements, the proposals would also add new disclosures for both public and nonpublic entities. All O&G entities should consider what, if any, revisions to existing processes or internal controls they would have to make to obtain and prepare the information needed to comply with the proposed new disclosure requirements.

¹² In ASC 740, income before income taxes is also referred to as pretax financial income.

Interim Reporting

To date, the FASB has discussed five interim reporting concepts under its proposed concepts statement. The Board generally agreed that interim financial statements should describe “differences in recognition, measurement, and presentation of line items” and should explain “how the interim period relates to the entire year.”¹³ Two of the interim reporting concepts pertained to disclosing changes from the latest annual financial statements, and two pertained to disclosing items that are not peripheral or are “especially important.”

To determine the meaning of “especially important,” the Board will assess the interim disclosure requirements being proposed in the Board’s project on reviewing fair value measurement disclosures as well as the interim disclosure requirements related to revenue in ASC 270-10-50-1A. On the basis of this process, the FASB can assess whether entities should disclose an item or amount that has not changed but is especially important.

Simplification Initiatives

Extraordinary Items

Introduction

On January 9, 2015, the FASB issued [ASU 2015-01](#), which eliminates from U.S. GAAP the concept of an extraordinary item. The Board released the new guidance as part of its simplification initiative, which, as explained in the ASU, is intended to “identify, evaluate, and improve areas of [U.S. GAAP] for which cost and complexity can be reduced while maintaining or improving the usefulness of the information provided to the users of financial statements.”

Key Provisions of the ASU

To be considered an extraordinary item under existing U.S. GAAP, an event or transaction must be unusual in nature and must occur infrequently. Stakeholders often questioned the decision-usefulness of labeling a transaction or event as extraordinary and indicated that it is difficult to ascertain whether an event or transaction satisfies both criteria. In light of this feedback and in a manner consistent with its simplification initiative, the FASB decided to eliminate the concept of an extraordinary item. As a result, an entity will no longer (1) segregate an extraordinary item from the results of ordinary operations; (2) separately present an extraordinary item on its income statement, net of tax, after income from continuing operations; and (3) disclose income taxes and earnings-per-share data applicable to an extraordinary item. However, the ASU does not affect the reporting and disclosure requirements for an event that is unusual in nature or that occurs infrequently.

Effective Date and Transition

For all entities, the ASU is effective for annual periods beginning after December 15, 2015, and interim periods within those annual periods. Entities may apply the guidance prospectively or retrospectively to all prior periods presented in the financial statements. If an entity chooses to apply the guidance prospectively, it must disclose whether amounts included in income from continuing operations after adoption of the ASU are related to events and transactions previously recognized and classified as extraordinary items before the date of adoption. Early adoption is permitted if the guidance is applied as of the beginning of the annual period of adoption.

¹³ Quoted text is from a [handout](#) for the Board’s January 7, 2015, meeting.

Debt Issuance Costs

Background

In April 2015, the FASB issued [ASU 2015-03](#), which changes the presentation of debt issuance costs in financial statements. Under the ASU, an entity presents such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. This treatment is consistent with the presentation of debt discounts under U.S. GAAP. Under previous guidance, an entity reported debt issuance costs in the balance sheet as deferred charges (i.e., as an asset). Amortization of the costs is reported as interest expense.

The amendments do not affect the current guidance on the recognition and measurement of debt issuance costs. For example, the costs of issuing convertible debt would not change the calculation of the intrinsic value of an embedded conversion option that represents a beneficial conversion feature under ASC 470-20-30-13. Thus, entities may still need to track debt issuance costs separately from a debt discount.

Revolving Debt Arrangements

Since the ASU's issuance, questions were raised regarding (1) the appropriate balance sheet presentation of costs incurred in connection with revolving-debt arrangements and (2) whether such costs are within the ASU's scope. At the EITF's June 18, 2015, meeting, it was confirmed that those costs are not within the scope of ASU 2015-03, and the SEC staff announced that it would "not object to an entity deferring and presenting [such] costs as an asset and subsequently amortizing the . . . costs ratably over the term of the line-of-credit arrangement." That announcement was codified in August 2015 by the issuance of [ASU 2015-15](#).

See Deloitte's June 18, 2015, [Heads Up](#) for additional information about ASU 2015-03, including further considerations of the treatment of costs associated with revolving-debt arrangements.

Effective Date and Transition

For PBEs, the guidance in ASU 2015-03 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. For entities other than PBEs, the guidance is effective for fiscal years beginning after December 15, 2015, and interim periods beginning after December 15, 2016. Early adoption is allowed for all entities for financial statements that have not been previously issued. Entities would apply the new guidance retrospectively to all prior periods (i.e., the balance sheet for each period is adjusted).

The ASU requires an entity to "disclose in the first fiscal year after the entity's adoption date, and in the interim periods within the first fiscal year, the following:

1. The nature of and reason for the change in accounting principle
2. The transition method
3. A description of the prior-period information that has been retrospectively adjusted
4. The effect of the change on the financial statement line item (that is, the debt issuance cost asset and the debt liability)."

Simplifying the Measurement of Inventory

On July 22, 2015, the FASB issued [ASU 2015-11](#), which requires entities to measure most inventory "at the lower of cost and net realizable value," thereby simplifying the current guidance under which an entity must measure inventory at the lower of cost or market (market in this context is defined as one of three different measures). The ASU will not apply to inventories that are measured by using either the last-in, first-out (LIFO) method or the retail inventory method (RIM).

Background

The project on simplifying the subsequent measurement of inventory is part of the FASB's simplification initiative. Launched in June 2014, the simplification initiative is intended to improve U.S. GAAP by reducing costs and complexity while maintaining or enhancing the usefulness of the related financial statement information. Simplification projects are narrow in scope, involve limited changes to U.S. GAAP, and can be completed quickly.

Under current guidance (i.e., ASC 330-10-35 before the ASU), an entity subsequently measures inventory at the lower of cost or market, with market defined as replacement cost, net realizable value (NRV), or NRV less a normal profit margin. An entity uses current replacement cost provided that it is not above NRV (i.e., the ceiling) or below NRV less an "approximately normal profit margin" (i.e., the floor). The analysis of market under current guidance requires the use of these ceilings and floors and is unnecessarily complex. The ASU eliminates this analysis for entities within the scope of the guidance.

Scope

The ASU applies to entities that recognize inventory within the scope of ASC 330, except for inventory measured under the LIFO or RIM method given certain challenges in applying the lower of cost or NRV approach to those methods.

Key Provisions of the ASU

Under the ASU, inventory is "measured at the lower of cost and net realizable value," which eliminates the need to determine replacement cost and evaluate whether it is above the ceiling (NRV) or below the floor (NRV less a normal profit margin). The ASU defines NRV as the "estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation." The Board did not amend other guidance on measuring inventory (e.g., the first-in, first out (FIFO); LIFO; or average cost method).

Effective Date and Transition

For PBEs, the ASU is effective prospectively for annual periods beginning after December 15, 2016, and interim periods therein. For all other entities, the ASU is effective prospectively for annual periods beginning after December 15, 2016, and interim periods thereafter. Early application of the ASU is permitted. Upon transition, entities must disclose the nature of and reason for the accounting change.

Simplifying the Accounting for Measurement-Period Adjustments

Background

In September 2015, the FASB issued [ASU 2015-16](#), which amended the guidance in ASC 805 on the accounting for measurement-period adjustments. The ASU was issued as part of the FASB's simplification initiative in response to stakeholder feedback that restating prior periods to reflect adjustments made to provisional amounts recognized in a business combination adds cost and complexity to financial reporting but does not significantly improve the usefulness of the information provided to users.

Key Provisions of the ASU

Under previous guidance, when an acquirer identified an adjustment to provisional amounts during the measurement period, the acquirer was required to revise comparative information for prior periods, including making any change in depreciation, amortization, or other income effects recognized in completing the initial accounting, as if the accounting for the business combination had been completed as of the acquisition date.

The ASU requires an acquirer to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The effect on earnings of changes in depreciation or amortization, or other income effects (if any) as a result of the change to the provisional amounts,

calculated as if the accounting had been completed as of the acquisition date, must be recorded in the reporting period in which the adjustment amounts are determined rather than retrospectively.

Disclosure Requirements

The ASU also requires that the acquirer present separately on the face of the income statement, or disclose in the notes, the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date.

Effective Date and Transition

For PBEs, the ASU is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. For all other entities, the ASU is effective for fiscal years beginning after December 15, 2016, and interim periods within fiscal years beginning after December 15, 2017. The ASU must be applied prospectively to adjustments to provisional amounts that occur after the effective date. Early application is permitted for financial statements that have not been issued.

The only disclosures required at transition will be the nature of and reason for the change in accounting principle. An entity should disclose that information in the first annual period of adoption and in the interim periods within the first annual period if there is a measurement-period adjustment during the first annual period in which the changes are effective.

For more information about the ASU, see Deloitte's September 30, 2015, [Heads Up](#).

Income Taxes Simplification Projects

On January 22, 2015, the FASB issued an [ED](#) of two proposed ASUs, one on intra-entity asset transfers and the other on balance sheet classification of deferred taxes, in an effort to simplify the accounting for income taxes.

Intra-Entity Asset Transfers

Under existing guidance, ASC 740-10-25-3 prohibits an entity from recognizing current and deferred income tax consequences of an intra-entity asset transfer until the entity sells the asset(s) to an outside party. The proposed ASU on intra-entity asset transfers would eliminate this prohibition and would require recognition of the income tax consequences upon transfer.

At its October 2015 meeting, the FASB redeliberated the proposed ASU on the basis of comment letters received from respondents. A number of constituents asserted that both costs and complexity would increase under this proposal. Some respondents proposed that the Board permit a practical expedient to continue the exception for intra-entity transfers of inventory while eliminating the exception for transfers of all other assets. The Board instructed its staff to perform additional research on these issues as well as outreach regarding the costs and benefits of a practical expedient for intra-entity inventory transfers. The Board will redeliberate the proposal at a future meeting and is expected to either eliminate the exception entirely (in a manner consistent with the current proposal) or establish the practical expedient, in which case the exception would be eliminated for all intra-entity asset transfers other than inventory.

For additional information about the proposed ASU, see Deloitte's January 30, 2015, [Heads Up](#).

Balance Sheet Classification of Deferred Taxes

On November 20, 2015, the FASB issued [ASU 2015-17](#), which requires entities to present DTAs and DTLs as noncurrent in a classified balance sheet. The ASU simplifies the current guidance, which requires entities to separately present DTAs and DTLs as current and noncurrent in a classified balance sheet.

Under current guidance (ASC 740-10-45-4), entities “shall separate deferred tax liabilities and assets into a current amount and a noncurrent amount. Deferred tax liabilities and assets shall be classified as current or noncurrent based on the classification of the related asset or liability for financial reporting.” Stakeholder feedback indicated that the separate presentation of deferred taxes as current or noncurrent provided little useful information to financial statement users and resulted in additional costs to preparers. Therefore, the FASB issued the ASU to simplify the presentation of deferred taxes in a classified balance sheet. Netting of DTAs and DTLs by tax jurisdiction will still be required under the new guidance.

Noncurrent balance sheet presentation of all deferred taxes eliminates the requirement to allocate a valuation allowance on a pro rata basis between gross current and noncurrent DTAs, which constituents had also identified as an issue contributing to complexity in accounting for income taxes.



For PBEs, the ASU will be effective for annual periods beginning after December 15, 2016, and interim periods within those years. For entities other than PBEs, the ASU will be effective for annual reporting periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018.

The Board decided to allow all entities to early adopt the ASU. Therefore, the ASU can be adopted by all entities for any interim or annual financial statements that have not been issued. In addition, entities are permitted to apply the amendments either prospectively or retrospectively.

In the period the ASU is adopted, an entity will need to disclose “the nature of and reason for the change in accounting principle.” If the new guidance is applied prospectively, the entity should disclose that prior balance sheets were not retrospectively adjusted. However, if the new presentation is applied retrospectively, the entity will need to disclose the quantitative effects of the change on the prior balance sheets presented.

Simplifying the Accounting for Employee Share-Based Payments

At its November 23, 2015, meeting, the FASB redeliberated on the [proposed ASU](#) on share-based payments as part of its simplification initiative. As a result of the redeliberations, the Board directed its staff to draft a final ASU for a vote by written ballot.

The final ASU will affect various aspects of the accounting for employee share-based payment transactions for both public and nonpublic entities, including the accounting for income taxes (e.g., the accounting related to excess tax benefits and deficiencies), forfeitures, minimum statutory withholding requirements, and classification in the statement of cash flows. In addition, the final ASU will contain two practical expedients for nonpublic entities under which such entities can use the simplified method to estimate the expected term of an award and make a one-time election to switch from fair value measurement to intrinsic value measurement for liability-classified awards. During its deliberations, the Board decided not proceed with its proposal to simplify the classification of awards with repurchase features. The Board noted that this issue may be addressed in the future as part of a project to distinguish equity from liabilities.

For public entities, the guidance in the upcoming ASU will be effective in annual reporting periods beginning after December 15, 2016, and interim periods within those reporting periods.

For nonpublic entities, such guidance will be effective in annual reporting periods beginning after December 15, 2017, and interim periods within annual periods beginning after December 15, 2018.

Early adoption will be permitted in any interim or annual period for which financial statements have not yet been issued or are not available to be issued. Issuance of the final ASU is expected in the first quarter of 2016.

For additional information about the proposed ASU and the Board's redeliberations, see Deloitte's June 12, 2015, [Heads Up](#) and its November 30, 2015, [journal entry](#).

Balance Sheet Classification of Debt

Background

This project is part of the FASB's simplification initiative. The objective of the project, as described in the Board's July 29, 2015, meeting [handout](#), is "to replace existing, fact-pattern-specific debt classification guidance with an overarching, cohesive principle to reduce cost and complexity for preparers and auditors when determining whether debt should be classified as current or noncurrent on the balance sheet, while improving the usefulness of the information reported to financial statement users."

The handout notes that at the FASB's January 28, 2015, meeting, the Board tentatively agreed on a classification approach under which an entity would "classify debt as noncurrent if one or both of the following criteria are met as of the balance sheet date:

- (a) The liability is contractually due to be settled more than 12 months (or operating cycle, if longer) after the balance sheet date.
- (b) The entity has a contractual right to defer settlement of the liability for at least 12 months (or operating cycle, if longer) after the balance sheet date."

Key tentative decisions made at the July 29, 2015, meeting are discussed below.

Scope

The proposed classification approach applies to debt arrangements that, as described in the meeting handout, "provide a lender a contractual right to receive money and a borrower a contractual obligation to pay money on demand or on fixed or determinable dates."

At its July 29, 2015, meeting, the Board tentatively decided to clarify that the approach applies to both (1) convertible debt (even though such instruments may be settled in shares) and (2) mandatorily redeemable financial instruments classified as liabilities under ASC 480-10 (even if such instruments are in the form of equity shares).

Waiver of Debt Covenant Violations

Under the Board's proposed classification approach, the determination of whether debt is current or noncurrent is made on the basis of the facts and circumstances that exist as of the balance sheet date. This proposal differs from current U.S. GAAP, under which an entity is permitted to consider certain post-balance-sheet events, such as a post-balance-sheet-date arrangement to refinance a short-term obligation on a long-term basis.

At its July 29, 2015, meeting, the Board tentatively decided to make one exception to its proposed approach. When a debtor violates a debt covenant on or before the balance sheet date and the long-term debt becomes a short-term obligation, it should not automatically be required to classify the debt as current. If the lender grants the debtor a waiver of the covenant before the debtor's financial statements are issued, the debtor would present the debt separately within long-term debt on the face of the balance sheet. The purpose of such presentation would be to notify financial statement users that such debt is classified as noncurrent even though the debtor violated one or more covenants as of the balance sheet date. The exception would not apply to waivers that involve a debt modification or extinguishment.

Further, the Board tentatively decided to retain existing U.S. GAAP guidance (ASC 470-10-45-1(b)) requiring that (1) the waiver of the current violation be for at least 12 months from the balance sheet date and (2) it is *not* probable that the borrower will be unable to comply with the covenant by the covenant compliance dates within the next 12 months.

Subjective Acceleration Clauses

Under the Board's proposed classification approach, debt that is callable by the creditor or due on demand is classified as current. During the Board's discussion on January 28, 2015, the staff suggested that debt subject to subjective acceleration clauses (SACs) would also be classified as current under the proposed classification approach.

However, at its July 29, 2015, meeting, the Board tentatively decided that SACs should affect classification only when triggered (in a manner similar to the treatment of debt covenant violations). Accordingly, a long-term obligation would be classified as noncurrent even if it is subject to an SAC. This decision differs from current U.S. GAAP, under which long-term obligations subject to SACs are sometimes classified as current (e.g., because of recurring losses or liquidity problems).

Disclosure and Transition

The Board tentatively decided to incorporate into U.S. GAAP the disclosure requirements related to debt covenant violations in SEC Regulation S-X, Rule 4-08 (ASC 235-10-S99-1(c)). Thus, such disclosures would be required for both public and nonpublic business entities. The Board also tentatively decided to require entities to disclose the nature and existence of significant SACs and debt covenants.

In addition, the Board tentatively decided to require prospective transition and that the transition disclosure requirements should be consistent with the applicable disclosure requirements in ASC 250-10-50. The effective date of the proposed guidance will be determined after the comment period.

Next Steps

The Board directed the staff to proceed with drafting a proposed ASU for a vote by written ballot. The proposed ASU will have a 60-day comment period.

Simplifying the Equity Method of Accounting

In June 2015, the FASB issued a [proposed ASU](#) on equity method accounting as part of its simplification initiative. The proposal aimed to eliminate the requirements for an investor to (1) account for the basis differences related to its equity method investees and (2) retroactively account for an investment that becomes newly qualified for use of the equity method because of an increase in ownership interest or degree of influence.

On the basis of the feedback received on its proposed ASU, the FASB directed the staff to perform additional research on whether to eliminate the requirement to account for the basis differences. However, the FASB decided to further clarify and finalize its proposed guidance related to eliminating the retroactive accounting for an investment that becomes newly qualified for use of the equity method of accounting upon an increase in ownership interest or degree of influence. The FASB clarified that unrealized holding gains or losses in accumulated other comprehensive income related to an available-for-sale security that becomes eligible for the equity method should be recognized in earnings as of the date on which the investment qualifies for the equity method.

The FASB directed the staff to draft a final standard for issuance, which is expected in the first quarter of 2016. The guidance in the ASU will be applied prospectively to increases in the level of ownership interest or degree of influence occurring after the final ASU's effective date. No transition disclosures will be required. For all entities, the final standard will be effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. In addition, all entities will be permitted to early adopt the guidance upon issuance of the final standard.

Accounting Alternatives for Private Companies

Background

The following guidance, developed by the Private Company Council (PCC), was issued in 2014:

- *Goodwill* — In January 2014, the FASB issued [ASU 2014-02](#), which allows private companies to use a simplified approach to account for goodwill after an acquisition. Under such approach, an entity would (1) amortize goodwill on a straight-line basis, generally over 10 years; (2) test goodwill for impairment only when a triggering event occurs; and (3) make an accounting policy election to test for impairment at either the entity level or the reporting-unit level. The ASU also eliminates “step 2” of the goodwill impairment test; as a result, an entity would measure goodwill impairment as the excess of the entity’s (or reporting unit’s) carrying amount over its fair value. An entity that elects the simplified approach should adopt the ASU’s guidance prospectively and apply it to all existing goodwill (and any goodwill arising from future acquisitions) existing as of the beginning of the period of adoption. The ASU is effective for annual periods beginning after December 15, 2014, and interim periods with annual periods beginning after December 15, 2015. See Deloitte’s January 27, 2014, [Heads Up](#) for more information.
- *Hedge accounting* — In January 2014, the FASB issued [ASU 2014-03](#), which gives private companies a simplified method of accounting for certain receive-variable, pay-fixed interest rate swaps used to hedge variable-rate debt. An entity that elects to apply the simplified hedge accounting to a qualifying hedging relationship would continue to account for the interest rate swap and the variable-rate debt separately on the face of the balance sheet. However, the entity would be able to assume no ineffectiveness in the hedging relationship, thereby essentially achieving the same income statement profile as with a fixed-rate borrowing expense. In addition, the entity is allowed more time to complete its initial hedge documentation. An entity that applies the simplified approach also may elect to measure the related swap at its settlement value rather than at fair value. The ASU is effective for annual periods beginning after December 15, 2014, and interim periods within annual periods beginning after December 15, 2015. Entities that elect the simplified approach should adopt the ASU under either a full retrospective or a modified retrospective method. See Deloitte’s January 27, 2014, [Heads Up](#) for more information.
- *Intangibles* — In December 2014, the FASB issued [ASU 2014-18](#), which gives private companies an exemption from having to recognize certain intangible assets for (1) assets acquired in a business combination or (2) investments accounted for under the equity method or upon the adoption of fresh-start accounting. Specifically, an entity would not be required to separately recognize intangible assets for noncompete agreements and certain customer-related intangible assets that arise within the scope of the ASU. Because the amounts associated with these items would be subsumed into goodwill, an entity that elects this accounting alternative would also be required to adopt ASU 2014-02 (see discussion above), resulting in the amortization of goodwill. Entities that elect the alternative should adopt the ASU prospectively to the first eligible transaction within the scope of the ASU that occurs in the annual period beginning after December 15, 2015 (with early adoption permitted), and all transactions thereafter. See Deloitte’s December 30, 2014, [Heads Up](#) for more information.

Proposed Changes to Effective Date and Transition Guidance in Certain Private-Company ASUs

In September 2015, the FASB issued for public comment a [proposed ASU](#) that would give private companies a one-time unconditional option to forgo a preferability assessment the first time they elect a PCC accounting alternative within the proposal’s scope. It would also eliminate the effective dates of PCC accounting alternatives that are within the proposal’s scope as well as extend the transition guidance in ASU 2014-02 and ASU 2014-03. The proposal’s amendments could affect all private companies within the scope of ASUs 2014-02 and 2014-03 as well as ASU 2014-07 and ASU 2014-18. See Deloitte’s October 6, 2015, [Heads Up](#) for more information.

Other Private-Company Matters

Throughout 2015, the PCC has discussed aspects of financial reporting that are complex and costly for private companies, including stock-based compensation, the application of VIE guidance to nonleasing common-control arrangements, and the balance sheet classification of debt.

The PCC also asked the FASB staff to research (1) examples that would clarify the application of VIE guidance to nonleasing common-control arrangements and (2) potential modifications to existing business scope exceptions to address application issues. The classification of debt will be discussed at a future meeting.

In addition, the PCC decided in February 2015 that it would not “amend the existing definitions of a nonpublic entity at this time. The existing definitions will remain in the FASB Codification until potentially amended at a later date by the FASB. The definition of a public business entity, [as amended by ASU 2013-12,] should continue to be used for future accounting and reporting guidance.”¹⁴



¹⁴ See the PCC’s [overview](#) of decisions reached on PCC Issue No. 14-01.

Section 3

Impairment and Valuation Considerations

Impairment Considerations Related to O&G Assets

O&G entities engaging in exploration and production (E&P) activities account for their operations by using either the successful-efforts method or the full-cost method. The fundamental difference between these two methods lies in their treatment of costs related to the exploration of new O&G reserves. The method used will directly affect how net income and cash flows are reported. Similarly, the choice of method will have a direct impact on the accounting for impairment.

Like O&G entities in the oilfield services, midstream, and downstream segments, E&P companies that use the successful-efforts method apply the impairment guidance in ASC 360-10, and such entities should consider this guidance when assessing potential impairment of O&G long-lived assets.

Successful-Efforts Method

Under the successful-efforts method, seismic costs are expensed as incurred and costs related to the successful identification of new O&G reserves may be capitalized while costs related to unsuccessful exploration efforts (i.e., drilling efforts that result in a dry hole) would be immediately recorded on the income statement. E&P companies that use the successful-efforts method apply the guidance in ASC 932-360-35 and ASC 360-10-35 to account for the impairment of their O&G assets. Such guidance addresses (1) the timing of impairment testing and impairment indicators, (2) measurement of an impairment loss, (3) the level at which an impairment is assessed, and (4) recognition of an impairment loss.

Timing of Impairment Testing and Impairment Indicators

Under the successful-efforts method, an E&P company generally performs a traditional two-step impairment analysis in accordance with ASC 360 when considering whether to assess proved oil and gas properties for indications of impairment. Generally, this analysis consists of determining when events or circumstances indicate that the carrying value of a company's O&G properties may not be recoverable.

Proved properties in an asset group should be tested for recoverability whenever events or changes in circumstances indicate that the asset group's carrying amount may not be recoverable. Generally, a company that applies the successful-efforts method will perform an annual impairment assessment upon receiving its annual reserve report by preparing a cash flow analysis as the necessary information becomes readily available. When performing an impairment analysis, such companies should consider risk factors for all reserve categories. Companies can consider proved (P1), probable (P2), and possible (P3) reserves and other resources since these are all included in the value of the assets.

E&P companies should assess unproved properties periodically (i.e., at least annually) to determine whether they have been impaired. The assessment of these properties is based mostly on qualitative factors. Key considerations include (1) development intent; (2) the primary lease term; and (3) recent development activity, including the drilling results of the entity and others in the industry as well as undeveloped-acreage merger and acquisition activity.

Measurement of Impairment Loss

A company that applies the successful-efforts method will test an asset group for impairment by using the two-step process detailed in ASC 360. Under step 1, the company will perform a cash flow recoverability test by comparing the asset group's undiscounted cash flows with the asset group's carrying value. The carrying amount of the asset group is not recoverable if it exceeds the sum of the undiscounted cash flows that are expected to result from the use and eventual disposition of the asset group.

If the asset group fails the cash flow recoverability test, the company will perform a fair value assessment under step 2 to compare the asset group's fair value with its carrying amount. An impairment loss would be recorded and measured as the amount by which the asset group's carrying amount exceeds its fair value, as determined in accordance with ASC 820.

Level at Which Impairment Is Assessed

When determining the level at which an impairment should be assessed, a company that applies the successful-efforts method should consider whether the property is proved or unproved. Proved properties must be grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. Typically, the impairment evaluation of O&G-producing properties is performed on a field-by-field basis or, if there is a significant shared infrastructure (e.g., platform), by logical grouping of assets. Unproved properties should be assessed on a property-by-property basis or, if acquisition costs are not significant, by an appropriate grouping.

Recognition of Impairment Loss

An impairment loss for a proved property asset group will reduce only the carrying amounts of the group's long-lived assets. A company should allocate the loss to the long-lived assets of the group on a pro rata basis by using the relative carrying amounts of those assets; however, the loss allocated to an individual long-lived asset of the group should not reduce the asset's carrying amount to less than its fair value if that fair value is determinable without undue cost and effort. For unproved properties, if the results of the assessment indicate impairment, a company should recognize a loss by providing a valuation allowance. Under the successful-efforts method, companies are prohibited from reversing write-downs.

Full-Cost Method

Unlike the successful-efforts method, the full-cost method allows E&P companies to capitalize nearly all costs related to the exploration and location of new O&G reserves regardless of whether their efforts were successful. To assess whether their O&G assets are impaired, E&P companies that use the full-cost method of accounting should apply the guidance in Regulation S-X, Rule 4-10; SAB Topic 12.D; and FRC Section 406.01.c. Like successful-efforts accounting guidance, this guidance addresses (1) the timing of impairment testing and impairment indicators, (2) measurement of an impairment loss, (3) the level at which an impairment is assessed, and (4) recognition of an impairment loss.

Timing of Impairment Testing and Impairment Indicators

Under the full-cost method, a full-cost ceiling test must be performed on proved properties each reporting period. Further, unproved properties must be assessed periodically (at least annually) for inclusion in the full-cost pool, subject to amortization.

Measurement of Impairment Loss

The full-cost accounting approach requires a write-down of the full-cost asset pool when net unamortized cost less related deferred income taxes exceeds (1) the discounted cash flows (DCFs) from proved properties (i.e., estimated future net revenues less estimated future expenditures to develop and produce proved reserves), (2) the cost of unproved properties not included in the costs being amortized, and (3) the cost of unproved properties included in the costs being amortized. The write-down would be reduced by the income tax effects¹ related to the difference between the book basis and the tax basis of the properties involved.

Level at Which Impairment Is Assessed

Companies that apply the full-cost method generally establish cost centers on a country-by-country basis and assess impairment at the cost-center level.

¹ For purposes of this calculation, the tax effects cannot result in a net tax benefit.

Recognition of Impairment Loss

When recognizing an impairment loss, companies that apply the full-cost method should reduce the carrying value of the full-cost asset pool and record the excess above the ceiling as a charge to expense in continuing operations. Like the successful-efforts method, the full-cost method precludes companies from reversing write-downs.

Thinking It Through

The downward decline in commodity prices may have impairment implications for E&P companies that use the full-cost method of accounting. Specifically, since the trailing 12-month prices in 2016 will continue to decline unless prices recover in the near term, it is likely that impairment risk will continue throughout 2016. Accordingly, E&P companies should focus on risk-based and early-warning disclosures when impairments are expected to occur in the future.

Impairment of Long-Lived Assets Under ASC 360-10

Falling commodity prices and other changes in the O&G industry may also directly affect the value of assets held by entities operating in other segments of the industry, including the oilfield services, midstream, and downstream sectors. Like other long-lived assets within the scope of the impairment guidance in ASC 360-10, assets in these O&G segments should be evaluated for impairment under ASC 360-10.

Timing of Impairment Testing and Impairment Indicators

O&G entities in the oilfield services, midstream, and downstream sectors would generally perform a traditional two-step impairment analysis in accordance with ASC 360 when considering whether to assess O&G assets for indications of impairment. Generally, O&G assets in an asset group should be tested for recoverability whenever events or changes in circumstances indicate that the asset group's carrying amount may not be recoverable. Examples include, but are not limited to, a major decline in the asset's market value, an adverse change in the manner or extent of the asset's use, and a current-period loss coupled with a history or expectation of future losses. When these indicators exist, an entity would be required to assess its assets for impairment.

Measurement of Impairment Loss

Oilfield services, midstream, and downstream entities will test an asset group for impairment by using the two-step process detailed in ASC 360. Under step 1, a company will perform a cash flow recoverability test by comparing the asset group's undiscounted cash flows with the asset group's carrying value. The carrying amount of the asset group is not recoverable if it exceeds the sum of the undiscounted cash flows that are expected to result from the use and eventual disposition of the asset group.

If the asset group fails the cash flow recoverability test, the company will perform a fair value assessment under step 2 to compare the asset group's fair value with its carrying amount. An impairment loss would be recorded and measured as the amount by which the asset group's carrying amount exceeds its fair value, as determined in accordance with ASC 820.

Recognition of Impairment Loss

An impairment loss for an asset group will reduce the carrying amounts of the group's long-lived assets. A company should allocate the loss to the long-lived assets of the group on a pro rata basis by using the relative carrying amounts of those assets; however, the loss allocated to an individual long-lived asset of the group should not reduce the asset's carrying amount to less than its fair value if that fair value is determinable without undue cost and effort. It is important to note that after an impairment loss is recognized, the adjusted carrying amount of the asset would be its new accounting basis. Subsequent reversal of a previously recognized impairment loss is prohibited.

Thinking It Through

The decrease in commodity prices may have a significant impact on the operations of O&G entities in the oilfield services, midstream, and downstream sectors. As a result, O&G entities may need to reassess the valuation of their assets under ASC 360-10 and other U.S. GAAP as follows:

- *Oilfield services* — As companies in the upstream sector curtail the number of drilling rigs that they are actively running in their programs, there may be a corresponding slowdown in services provided as a result of fewer actively working rigs in 2016. Therefore, fewer wells are expected to be completed and brought online. Like companies in the midstream sector, oilfield services companies may need to consider the potential impacts of a reduction in upstream activity on their future cash flows.
- *Midstream* — If the upstream sector begins to curtail drilling operations, production is likely to decrease. Consequently, the midstream sector should focus on impairment indicators as a result of the potential decline in production, which could lead to lower gathering and processing volumes.
- *Downstream* — Companies in the downstream sector that have acquired significant inventory over the past several years may have LIFO layers currently recorded at much higher prices. Therefore, they may have to consider the declining commodity prices in the context of their inventory valuation as well as the valuation of long-lived assets.

Valuation of O&G Assets

Valuation Approaches

To determine the fair value of assets, valuation specialists primarily rely on three approaches:

- *Income approach* — Under this approach, valuation techniques are used to convert future amounts (e.g., cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.
- *Market approach* — This approach requires entities to consider prices and other relevant information in market transactions that involve identical or comparable assets or liabilities, including a business. Valuation techniques commonly used under the market approach include the guideline public company method² and the guideline transaction method.³
- *Asset approach* — Under this approach, which is also known as the cost approach, the value of a business, business ownership interest, or tangible or intangible asset is estimated by determining the sum required to replace the investment or asset with another of equivalent utility (sometimes described as future service capability).

In certain situations, valuation specialists may employ multiple valuation approaches when performing a fair value analysis to explore different scenarios and confirm the reasonableness of an estimate. The usefulness of a particular valuation approach may vary from year to year.

Although companies in the industry most commonly apply the income approach (by using a DCF model), other approaches may be more appropriate in certain circumstances. Further, an alternative such as the market approach is often used to confirm the reasonableness of the DCF model.

² The guideline public company method employs market multiples derived from stock prices of companies engaged in the same or similar lines of business whose shares are actively traded in a free and open market. The application of the selected multiples to the corresponding measure of financial performance for the subject company produces estimates of value at the marketable minority level.

³ The guideline transaction method, also referred to as the transaction method or the merger and acquisition method, relies on pricing multiples derived from transactions of significant interests in companies engaged in the same or similar lines of business. The application of the selected multiples to the corresponding measure of financial performance for the subject company produces estimates of value at the marketable control level.

Thinking It Through

When determining the fair value of O&G reserves, E&P companies use various methods and approaches. Approximately 90 percent of them use a DCF model to estimate the fair value of O&G reserves. A rule-of-thumb method of determining these reserves' fair value, although not originally intended for that purpose, is the SEC's "PV-10," under which fair value is defined as the present value of the estimated future O&G revenues, reduced by direct expenses and discounted at an annual rate of 10 percent. While the SEC's overall goal in requiring registrants to use this metric was to make amounts reported by companies comparable, it is now frequently used to evaluate the fair value of E&P companies' proved O&G reserves.

The 10 percent discount rate can serve as the starting point for discounting projected cash flows from proved O&G reserves in an investor case reserve report. Further analysis should then be conducted to determine the appropriate rate to be applied to the amounts in the report. This analysis, which may vary by reserve category, will involve judgment and should be based on the company's specific facts and circumstances.

Key Assumptions Under the Income Approach

In determining the fair value of their assets, O&G companies must ensure that the valuation approach and related model they use are based on appropriate and accurate assumptions that are consistent with the market participant concept (i.e., they must use factors and assumptions that would be used by buyers and sellers in the principal or most advantageous market for the asset or liability). Assumptions that companies should consider incorporating in the DCF model include those related to (1) cash flow projections, (2) pricing and price differentials, (3) discount rate, (4) risk factors, and (5) the tax effect. Understanding the basis for those assumptions is just as important as understanding their nature.



Thinking It Through

When applying the income approach, O&G companies should evaluate the assumptions to be used in their DCF models as follows:

Cash Flow Projections

O&G companies need to determine the cash flow projections that will be incorporated in their DCF models. Generally, these projections are based on a production profile that is developed by a third-party engineering firm or prepared internally by company engineers.

Pricing and Price Differentials

Generally, E&P companies use forward strip pricing as determined by the New York Mercantile Exchange (NYMEX) or other pricing benchmarks (e.g., Brent, WTI) in their DCF models. Forward strip pricing over a period of up to five years is useful for valuation purposes since there is active futures trading activity within that time horizon. Beyond the last date of the forward strip, a company should estimate prices by using more subjective judgments that typically involve applying an inflation factor to the NYMEX futures price. Pricing benchmarks can vary greatly depending on location.

Commodity price differentials are another key metric that could affect the assumptions used in the DCF model. Oil and natural gas prices can vary as a result of multiple factors, including (1) quality, (2) transportation costs, and (3) proximity to market or delivery point.

Discount Rate

E&P companies should consider various factors when determining the discount rate to use in their valuation models. One consideration is the basis for the discount rate (e.g., whether to use a weighted average cost of capital (WACC)⁴ rate or rates detailed in the SPEE⁵ annual survey). Also, companies need to consider whether to use an after-tax discount rate or after-tax undiscounted cash flows in their fair value calculations.

Risk Factors

Since unproved reserves are inherently more uncertain than proved reserves, risk factors related to unproved reserves are much more significant than those related to proved reserves. Therefore, risk factors are applied to the valuation of unproved (i.e., P2 and P3) reserves.

When E&P companies perform an impairment analysis under the successful-efforts method, they typically use a zero percent risk factor for proved properties. When these companies perform purchase accounting, however, they apply a variety of risk factors to different categories of proved reserves.

This seeming inconsistency in practice could prompt auditors and regulators to raise questions about how the risk factors are being applied. Further, when E&P companies perform a valuation of O&G assets, they either (1) incorporate the risk factors in the discount rate or (2) apply the risk factors to DCFs.

Tax Effect

E&P companies should also consider whether to incorporate assumptions about the tax effect in the DCF models. This consideration is critical since results may vary depending on whether pretax or post-tax amounts are used. Generally, pretax models are more commonly used in the valuation of O&G assets outside the United States.

⁴ The WACC is the rate that a company is expected to pay on average to all of its securityholders to finance its assets.

⁵ The Society of Petroleum Evaluation Engineers (SPEE) conducts an annual survey of industry executives, consultants, and other energy industry stakeholders to develop insights about the risk factors and discount rates commonly used in analyzing property values throughout the O&G industry. This survey could serve as a good reference point for determining the appropriateness of the assumptions used to measure the fair value of proved reserves.

Key Assumptions Under the Market Approach

As they would under the income approach, O&G companies should apply the market participant concept when determining the fair value of their O&G assets under the market approach. For example, discount rates should be estimated from the standpoint of other buyers and sellers. Although fair value from the market participant's point of view is often the same as fair value from an O&G company's standpoint, the company should ensure that it is considering the same factors and assumptions that the market participant would take into account.

Selecting the Appropriate Method

When applying the market approach, an O&G company must first determine the appropriate method to use (i.e., either the guideline public company method or the guideline transaction method) by considering various factors. These factors vary depending on the particular O&G sector in which the company operates.

E&P companies should select a method on the basis of the following considerations:

- Size (market capitalization or reserve volumes).
- Natural gas versus oil mix (i.e., the percentage of reserves or production represented by natural gas versus oil).
- Reserve life.
- Areas or basins of operation.

Generally, the guideline transaction method is challenging for E&P companies to use because (1) finding new resource plays is difficult, (2) multiples in the same play can vary greatly, and (3) undeveloped acreage multiples from market transactions are rarely published. Companies operating in the oilfield services sector should consider the following factors when determining which method to use:

- Similar mix of operations (e.g., onshore and offshore, regional and global).
- Operational makeup (i.e., technology, equipment, construction).

Finally, companies operating in the downstream sector should consider the following:

- Locations and access to cheaper crude oil.
- Crude oil capacity.
- Refining complexity (i.e., complexity is an indication of the value of the refined products that a refinery produces).
- Utilization (i.e., refineries with similar utilization rates are comparable).
- Diversification (i.e., pure-play refiners are not comparable to refiners that also have midstream assets).

Thinking It Through

Generally, Deloitte valuation specialists use the market approach to confirm reasonableness when a valuation was not primarily based on a DCF estimate. Regulators have indicated that multiple approaches may be used to measure the value of assets and liabilities. When using the market approach, a company should ensure that it is "comparing apples to apples" because there could be significant differences among market transactions and among peer companies. For example, transactions that are seemingly similar can differ significantly, especially if they involve different resource plays.

Section 4

Implications of the New Revenue Model

Background

On May 28, 2014, the FASB and IASB issued their final standard on revenue from contracts with customers. The standard, issued as [ASU 2014-09](#) by the FASB and as IFRS 15 by the IASB, outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance.¹ The main provisions of the ASU are codified in ASC 606.

The goals of the ASU are to clarify and converge the revenue recognition principles under U.S. GAAP and IFRSs while (1) streamlining, and removing inconsistencies from, revenue recognition requirements; (2) providing “a more robust framework for addressing revenue issues”; (3) making revenue recognition practices more comparable; and (4) increasing the usefulness of disclosures. The ASU states that the core principle for revenue recognition is that an “entity shall recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.”

As a result of the ASU, entities will need to comprehensively reassess their current revenue accounting and determine whether changes are necessary. Entities are also required to provide significantly expanded disclosures about revenue recognition, including both quantitative and qualitative information about (1) the amount, timing, and uncertainty of revenue (and related cash flows) from contracts with customers; (2) the judgment, and changes in judgment, used in applying the revenue model; and (3) the assets recognized from costs to obtain or fulfill a contract with a customer.

The FASB recently issued [ASU 2015-14](#), which defers the effective date of ASU 2014-09 by one year for all entities reporting under U.S. GAAP and permits early adoption as of the original effective dates. Refer to [Effective Date and Transition](#) below for further discussion of the effective date. In addition, in response to feedback received by the FASB-IASB joint revenue recognition transition resource group (TRG), the FASB is considering certain revisions to the guidance in the new revenue standard (as is the IASB, which has proposed revisions of its own in its July 2015 [ED](#)). Those contemplated revisions are discussed in three proposed ASUs:

- *Narrow-Scope Improvements and Practical Expedients* — Issued on September 30, 2015, this [proposed ASU](#) proposes to (1) clarify how to assess whether collectibility of consideration to which an entity is entitled is probable under certain circumstances, (2) add a practical expedient permitting sales taxes to be presented on a net basis in revenue, (3) clarify how to account for noncash consideration at contract inception and throughout the contract period, and (4) add a practical expedient to facilitate how to assess the impact of historical contract modifications upon transition. See Deloitte’s October 2, 2015, [Heads Up](#) for more information.
- *Principal Versus Agent Considerations (Reporting Revenue Gross Versus Net)* — Issued on August 31, 2015, this [proposed ASU](#) seeks to address issues regarding how an entity should assess whether it is the principal or the agent in contracts that include three or more parties. Specifically, the proposed ASU attempts to clarify (1) how to determine the unit of account for the principal-versus-agent assessment, (2) how the principal-versus-agent indicators in ASC 606 would help an entity determine whether it obtains control of a good or service (or a right to a good or service) before the good or service is transferred to the customer, and (3) how certain indicators are related to ASC 606’s general control principle. In addition, the proposed ASU would clarify that an entity (1) should evaluate whether it is the principal or the agent for each specified good or service in a contract and (2) could be the principal with respect to certain distinct performance obligations in a contract and the agent with respect to others. See Deloitte’s September 1, 2015, [Heads Up](#) for more information.
- *Identifying Performance Obligations and Licensing* — Issued on May 12, 2015, this [proposed ASU](#) aims to clarify the new revenue standard’s guidance on an entity’s identification of certain performance obligations. The proposal would add guidance on immaterial promised goods and services and separately identifiable promises. Other proposed amendments include (1) a policy election for shipping and handling fees incurred after control of a good is transferred to a customer and (2) clarifications related to licenses. See Deloitte’s May 13, 2015, [Heads Up](#) and its October 8, 2015, [journal entry](#) for more information.

¹ The SEC has indicated that it plans to review and update the revenue recognition guidance in SEC Staff Accounting Bulletin (SAB) Topic 13, “Revenue Recognition,” in light of the issuance of the ASU. The extent to which the ASU’s guidance will affect a public entity will depend on whether the SEC removes or amends the guidance in SAB Topic 13 to be consistent with the new revenue standard.

Key Accounting Issues

Although ASU 2014-09 and related proposed amendments may not significantly change how O&G entities typically recognize revenue, certain requirements of the ASU may require a change from current practice. Discussed below are (1) some key provisions of the ASU that may affect O&G entities and (2) how the guidance might be considered in some typical transactions.

Thinking It Through

To help O&G entities implement the ASU, the FASB and IASB created their joint TRG on revenue recognition and the AICPA assembled an O&G industry task force.² In addition, the AICPA is currently developing an accounting guide on revenue recognition. See Deloitte's *TRG Snapshot* publications for information about the topics discussed to date by the TRG.

Contract Modifications

O&G entities should consider how they are affected by the ASU's guidance on accounting for "approved" modifications to contracts with customers. The approval of a contract modification can be in writing, by oral agreement, or implied by customary business practices, and a contract modification is considered approved when it creates new, or changes existing, enforceable rights or obligations. A contract modification must be accounted for as a separate contract when (1) it results in a change in contract scope because of additional promised "distinct" goods or services (see [Distinct Performance Obligations](#) below) and (2) the additional consideration reflects the entity's stand-alone selling price for those additional promised goods or services (including any appropriate adjustments to reflect the circumstances of the contract). That is, the entity would continue to account for the existing contract as if it was not modified and account for the additional goods or services provided in the modification as a "new" contract.

If a contract modification is not considered a separate contract (i.e., it does not meet the criteria above), an entity should evaluate the remaining goods and services in the modified contract and determine whether to account for the modification prospectively (if the remaining goods and services are distinct from those already transferred) or retrospectively in accordance with the ASU. If the remaining goods and services are distinct from those already transferred, the modification is accounted for prospectively, the transaction price is updated (i.e., it now includes both the remaining consideration from the original contract and the additional consideration in the modification), and the updated transaction price is allocated to the remaining goods and services to be transferred. In contrast, if the goods or services are not distinct and are part of a single performance obligation, the modification is treated retrospectively and the amount of revenue recognized to date is adjusted to reflect the new modified contract (e.g., the measure of progress is adjusted to account for the new expectation of performance completed), resulting in a cumulative-effect catch-up adjustment.

Thinking It Through

As discussed above, on September 30, 2015, the FASB issued a proposed ASU that would add a practical expedient to facilitate how to evaluate historical contract modifications at transition. O&G entities should consider the operational challenges of identifying historical contract modifications, looking back to determine the transaction price for all satisfied and unsatisfied performance obligations, and allocating the transaction price. The proposed ASU would also define completed contracts as those for which all (or substantially all) revenue was recognized under the applicable revenue guidance before the new revenue standard was initially applied.

² Deloitte is represented on both the TRG and the AICPA task force.

Blend-and-Extend Contract Modifications

In a typical B&E modification, the supplier and customer may renegotiate the contract to allow the customer to take advantage of lower commodity pricing while the supplier increases its future delivery portfolio. Under such circumstances, the customer and supplier agree to “blend” the remaining, original, higher contract rate with the lower, extension-period rate for the remainder of the original contract term plus an extended term. The supplier therefore defers the cash realization of some of the contract fair value that it would have received under the original contract terms until the extension period, at which time it will receive an amount that is greater than the current market price for those periods as of the date of the modification.

Potential Impact of the New Revenue Model on B&E Contract Modifications

O&G entities should carefully evaluate the facts and circumstances related to a B&E contract modification to determine whether it should be accounted for as a new contract or as a prospective contract modification. A contract modification is treated as a new contract when distinct goods or services are added to the contract and the additional consideration reflects the stand-alone selling price of those additional goods or services.

For B&E contract modifications, stakeholders have questioned how the payment terms affect the evaluation of whether the contract should be accounted for as a modification or as a separate contract. That is, there has been uncertainty about whether entities should compare (1) the price the customer will pay for *those* added goods or services (i.e., the blended price paid for the goods or services delivered during the added contract period) with the stand-alone selling price of those goods or services or (2) the total increase in the aggregated contract price with the stand-alone selling price of the added goods or services.

In addition, the total transaction price may need to be reevaluated because the blending of the prices may create a significant financing component under the view that some of the consideration for the future goods or services is paid early as a result of the “blended” price agreed to by the parties.

An AICPA industry task force discussed with the AICPA’s revenue recognition working group (RRWG) the issue of whether a B&E contract modification should be accounted for as (1) a separate contract or (2) the termination of an existing contract and the creation of a new contract. It was agreed that the issue should be elevated to the TRG in the second half of 2015. However, the TRG did not discuss this issue at its November 2015 meeting. In January 2016, the FASB staff responded to the issue through a technical inquiry, the results of which will be published through the AICPA industry task force processes.

Commodity Exchange Arrangements

Commodity exchange arrangements are common in the O&G industry. In these arrangements, an entity agrees to sell a certain quantity and grade of a commodity to a counterparty at a specified location and simultaneously agrees to buy a specific quantity and grade of a similar commodity from that same counterparty at another location. In effect, specified inventories of the two parties are exchanged (e.g., in-ground natural gas inventories are exchanged at different storage hubs). Entities usually enter into such arrangements to avoid ancillary costs (e.g., transportation costs).

Companies may need to determine whether these types of arrangements are outside the scope of the new revenue recognition model and are instead accounted for under ASC 845. Generally, the purpose of exchange arrangements is to allow the parties to meet the needs of the market; therefore, the parties in such arrangements are not considered to be the end-user purchasers of the product if they are in the same line of business. Although a counterparty in a commodity exchange arrangement may meet the ASU’s definition of a “customer,” nonmonetary exchanges between two parties in the “same line of business” are outside the new standard’s scope. Therefore, the new revenue model is not expected to have a significant impact on commodity exchange arrangements.

However, under the FASB's September 30, 2015, proposed ASU discussed above, the measurement date for noncash consideration would be contract inception. Therefore, for nonmonetary exchange contracts with customers that are not in the same line of business, O&G entities would need to measure the fair value of in-kind payments at contract inception and consider whether changes in the value to be delivered in settling the contract as a result of changing forward commodity prices should be separately accounted for (e.g., as an embedded derivative for potential bifurcation).

Thinking It Through

In certain arrangements, a marketer may agree to sell crude oil to a refiner (or gas to a gas processor) and simultaneously buy back separate, refined products such as condensates (or natural gas liquids). O&G entities should be aware that although such agreements may be structured similarly to the commodity exchange arrangements discussed above, the applicability of the ASU to the two types of arrangements may differ. For example, O&G entities may need to assess whether the refining or processing counterparty meets the definition of a customer in the ASU or should be accounted for under other U.S. GAAP.

Production Imbalances

Production imbalances in a well arise when working interest owners in a production-sharing arrangement sell more ("overlift") commodity production in a given period than they are entitled to sell according to their working interest ownership percentages. The overlift party thus has an obligation to settle the imbalance with the underlift party financially or in kind by the end of the property's life.

Current guidance in ASC 932-10-S99-5 generally permits owners to record revenue related to a production-sharing arrangement by using either the entitlements method or the sales method. Under the entitlements method, an owner generally records revenue equivalent to its share of production and a payable (overlift) or receivable (underlift) for the difference between volumes it actually sold to third parties and its working interest. Under the sales method, an owner generally records revenue for the actual amount of the production sold to third parties and adjusts reserves for any shortfall.

Identifying the Contract With the Customer

If the sales contract with the third party is considered a contract with a customer,³ revenue on those sales would be recognized in accordance with the new model. Further, while the SEC staff's accounting guidance on the sales and entitlements methods (ASC 932-10-S99-5) currently remains in effect, it does not preclude the underlift party from accounting for the production imbalance under the new revenue model if the overlift party meets the definition of a customer in the ASU.

O&G entities should consider whether an underlift party's production imbalance with an overlift party constitutes a contract with a customer that should be accounted for under ASU 2014-09 or whether the SEC's current industry guidance in ASC 932-10-S99-5 would be more applicable. If an O&G entity determines that a production imbalance should be accounted for under the ASU, it should consider the potential applicability of the considerations discussed below, including volumetric optionality (see [Volumetric Optionality](#) below).

³ ASU 2014-09 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 in exchange for consideration."

Thinking It Through

The ASU does not amend the SEC’s guidance in ASC 932-10-S99-5, which states that both the sales and entitlements methods of accounting for production imbalances are acceptable. However, [comments](#) made by SEC Deputy Chief Accountant Wesley Bricker in September 2015 indicate that the SEC staff may remove some of its industry-specific revenue recognition guidance for O&G entities:

For example, consider the variety of arrangements entered into by participants in the oil and gas industry — joint ownership, operating, sales, and gas balance agreements. These arrangements are currently accounted for in accordance with industry-specific guidance, including a non-authoritative 1986 paper from the Council of Petroleum Accountants Societies and an SEC Observer comment [in ASC 932-10-S99-5]. Since we now have a comprehensive standard for revenue recognition in Topic 606 that will apply to all industries when effective, OCA intends to remove the SEC Observer comment coincident with the new standard’s effective date. After we remove the SEC Observer comment, I would expect industry participants to apply relevant authoritative accounting literature to the recognition, measurement, presentation, and disclosure of the various arrangements.

O&G entities should continue to monitor the SEC’s revenue recognition guidance in SAB topics for any potential changes.

Distinct Performance Obligations

The ASU provides guidance on evaluating the promised “goods or services”⁴ in a contract to determine each performance obligation (i.e., the unit of account). A performance obligation is each promise to transfer either of the following to a customer:

- “A good or service (or a bundle of goods or services) that is distinct.”
- “A series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer.”

Under the ASU, a series of distinct goods or services has the same pattern of transfer if both of the following criteria are met: (1) each distinct good or service in the series meets the criteria for recognition over time and (2) the same measure of progress is used to depict performance in the contract. Therefore, if a simple forward sale of oil or natural gas for which delivery of the same product is required over time is deemed to be immediately consumed or used by the customer (i.e., deliveries received are not stored), the forward sale could be treated as a single performance obligation that is satisfied over the contract term. In this case, an O&G entity would determine an appropriate method for measuring progress toward complete satisfaction of the single performance obligation and would recognize the transaction price as revenue as progress is made.

⁴ Although the ASU does not define goods or services, it includes several examples, such as goods produced (purchased) for sale (resale), granting a license, and performing contractually agreed-upon tasks.

Thinking It Through

Stakeholders have raised questions regarding the determination of when an entity transfers control of a commodity. Specifically, they have questioned whether long-term contracts to deliver commodities that are not always immediately consumed by the customer (e.g., crude oil or natural gas, which, unlike electricity, can be efficiently stored for a later use) could be accounted for as a series and, therefore, a single performance obligation that is satisfied over time. The TRG discussed aspects of this issue at its July 2015 meeting, during which TRG members generally agreed with the FASB and IASB staffs' conclusion that an entity should consider "all relevant facts and circumstances, including the inherent characteristics of the commodity, the contract terms, and information about infrastructure or other delivery mechanisms." However, the TRG did not specifically address application of the series guidance to storable commodities. An AICPA industry task force has developed a position on this matter that seeks to allow the application of the series guidance to storable commodities in certain scenarios and will be sharing this position with the RRWG in early 2016 for the working group's consideration.

Variable Pricing

The ASU requires that variable consideration be included in the transaction price under certain circumstances. An estimate of variable consideration is only included in the transaction price to the extent that it is probable⁵ that subsequent changes in the estimate would not result in a "significant reversal" of revenue. This concept is commonly referred to as the "constraint." The ASU requires entities to perform a qualitative assessment that takes into account the likelihood and magnitude of a potential revenue reversal and provides factors that could indicate that an estimate of variable consideration is subject to significant reversal (e.g., susceptibility to factors outside the entity's influence, long period before uncertainty is resolved, limited experience with similar types of contracts, practices of providing concessions, or a broad range of possible consideration amounts). This estimate would be updated in each reporting period to reflect changes in facts and circumstances.

The use of variable consideration (e.g., index or formula-based pricing) may present challenges related to estimating and allocating the transaction price and applying the ASU's constraint guidance. When the transaction price includes a variable amount, an entity must estimate the variable consideration by using either an "expected value" (probability-weighted) approach or a "most likely amount" approach, whichever is more predictive of the amount to which the entity expects to be entitled.

When an arrangement includes variable consideration, O&G entities should also consider whether (1) the practical expedient for measuring progress completed for performance obligations satisfied over time can be applied or (2) changes in variable consideration can be allocated to satisfied portions of distinct services provided to the customers.

O&G entities that have arrangements that include both price and volume variability should consider whether the volume variability is actually the result of optional purchase (see [Volumetric Optionality](#) below). Options for customers to purchase additional goods or services from an O&G entity would not be considered performance obligations (and therefore, the resulting consideration would not be included in the transaction price) unless the options give rise to a material right. If the optional purchases do not give rise to a material right, the O&G entity would only account for the optional purchases once the options are exercised.

Volumetric Optionality

The ASU contains implementation guidance on recognizing revenue related to options for additional goods or services (i.e., written volumetric optionality). Upstream and marketing companies should carefully consider any additional quantities that the customer has rights to in take-or-pay or other off-take arrangements and whether such volumetric optionality

⁵ "Probable" in this context has the same meaning as in ASC 450-20: "the event or events are likely to occur." In IFRS 15, the IASB uses the term "highly probable," which has the same meaning as the FASB's "probable."

represents a separate performance obligation in the contract. If a right to additional quantities results in a material right that the customer would not otherwise receive had it not entered into that contract, the option is considered a separate performance obligation. For example, a material right may be identified for additional quantities at prices that are significantly in-the-money (as determined at contract inception).

The consideration in a contract that includes options for additional goods or services may include an up-front payment. For example, that payment may reflect the present value of the difference between a fixed price for optional quantities and consideration determined by using the supplier's forward commodity price curve. When that is the case, the up-front payment is included in the overall transaction price, which would be allocated by applying the ASU's allocation method to the performance obligations identified (which may include a separate performance obligation for a material right). In addition, the entity should evaluate whether a significant financing component is present (see [Significant Financing Component](#) below).

Significant Financing Component

Adjustments for the time value of money are required if the contract includes a "significant financing component" (as defined in the ASU). Generally, no adjustment is necessary if payment is expected to be received within one year of the transfer of related goods or services to the customer. However, if an entity concludes, on the basis of the payment terms, that there is a significant financing component, it should adjust the sales price when recording revenue to present the amount that would have been attained had the buyer paid cash for the goods or services on the date of sale.

Thinking It Through

Payment terms in the O&G industry often include up-front fees or extended payment terms (e.g., long-term volumetric production payments). Under current guidance, arrangements that offer extended payment terms often result in the deferral of revenue recognition since the fees are typically not considered fixed or determinable unless the entity has a history of collecting fees under such payment terms without providing any concessions. In the absence of such a history, revenue is recognized when payments become due or when cash is received from the customer, whichever is earlier. Typically, under today's accounting, there would be no adjustment for advance payments.

Under the ASU, if the financing term extends beyond one year and a significant financing component is identified, the entity would need to initially estimate the transaction price by incorporating the impact of any potential price concessions (see discussion above in [Variable Pricing](#)) and then adjust this amount to account for the time value of money. That amount adjusted for any concessions and the time value of money would then be recognized as revenue when the entity transfers control of the good or service to the customer. When the entity is providing financing, interest income would be recognized as the discount on the receivable unwinds over the payment period. However, when the entity receives an up-front fee, the entity is deemed to be receiving financing from the customer and interest expense is recognized, with a corresponding increase to revenue recognized. This recognition pattern may differ significantly from the pattern under current U.S. GAAP, as described above.

Take-or-Pay Arrangements

In a take-or-pay arrangement, a customer pays a specified price to a supplier for a minimum volume of product or level of services. Such an arrangement is referred to as "take-or-pay" because the customer must pay for the product or services regardless of whether it actually takes delivery. Natural gas and other commodity off-take contracts are commonly structured as take-or-pay. Service arrangements, such as those for natural gas storage or transportation, can also be structured as take-or-pay. These arrangements may have characteristics similar to those of other "stand ready" obligations in which an entity is required to pay for the availability of a resource regardless of whether the entity actually uses the resource.

Identifying the Performance Obligations in the Contract

Under the ASU, a supplier in a take-or-pay arrangement could conclude that it has entered into a contract with a customer to deliver a series of distinct, but substantially the same, goods or services consecutively over time (see discussion above in [Distinct Performance Obligations](#)). Therefore, the supplier should account for that series of distinct goods or services as a single performance obligation — and as a single unit of account — when both of the following criteria are met:

- The customer simultaneously receives and consumes the benefits of each distinct delivery (or period of availability) of natural gas or another commodity (e.g., if the delivery of natural gas or another commodity meets the criterion in ASC 606-10-25-27(a) and, as a result, the series meets the criterion in ASC 606-10-25-15(a)).
- The same measure of progress for each distinct delivery of natural gas or another commodity (e.g., a time- or unit-based measure) would be used, thereby satisfying the criterion in ASC 606-10-25-15(b).

Recognizing Revenue When (or as) Performance Obligations Are Satisfied

If it is determined that the performance obligation in a take-or-pay arrangement is satisfied over time, the supplier recognizes revenue by measuring progress toward satisfying the performance obligation in a manner that best depicts the transfer of goods or services to the customer. The best depiction of the supplier's performance in transferring control of the goods and satisfying its performance obligation may differ depending on the terms of the take-or-pay arrangement.

Consider a vanilla take-or-pay arrangement involving monthly deliveries of natural gas in which the customer pays irrespective of whether it takes delivery and cannot make up deliveries not taken. In this case, it may be appropriate for the supplier to use an output measure of progress based on time to recognize revenue because the performance obligation is satisfied as each month passes.

Drilling Contracts

Whether for developing properties offshore or on land, drilling contracts are often complex, involving significant amounts of consideration and including specialized assets and service offerings in various forms (e.g., daywork, turnkey). Drilling contractors will need to carefully evaluate whether their contracts are — or contain — leases within the scope of ASC 840.⁶ If a contract (or part of a contract) is within the scope of ASC 606, the contractor should perform the steps discussed below under the new revenue model.

Identifying the Performance Obligations in the Contract

Drilling contracts often contain “mobilization” or “localization” terms under which the drilling contractor is to move an agreed-upon drilling rig and equipment from a current location to the drilling site (or sites). For example, in offshore, daywork drilling contracts, there is often an explicit day rate for mobilization work and periods. This day rate is generally lower than the day rate for the actual drilling period and corresponding activities.

Contractors should carefully examine which activities in a drilling contract constitute a promise to transfer a good or service to a customer (i.e., form part of a performance obligation). ASC 606-10-25-17 states the following regarding identification of a performance obligation in a contract:

Performance obligations do not include activities that an entity must undertake to fulfill a contract unless those activities transfer a good or service to a customer. For example, a services provider may need to perform various administrative tasks



⁶ Drilling contractors may also need to evaluate their contracts upon the issuance of the FASB's new guidance on leases (the IASB's new guidance on leases, IFRS 16, was issued on January 13, 2016) since such guidance could affect the determination of whether these contracts are or contain leases.

to set up a contract. The performance of those tasks does not transfer a service to the customer as the tasks are performed. Therefore, those setup activities are not a performance obligation.

On the basis of discussion at the TRG's November 2015 meeting, drilling contractors may find it helpful in this determination to consider whether an activity such as mobilization transfers control of a good or service over time. That is, if the activity meets one of the criteria in ASC 606-10-25-27, it is likely that the contractor transfers a good or service to the operator and that the activity is thus part of a performance obligation (or a performance obligation if the good or service is distinct).

However, a drilling contractor may conclude that such an activity is necessary to fulfill the larger drilling contract (i.e., it is a set-up or fulfillment activity) and is not a promise to deliver a service to the well operator (i.e., the customer). In this instance, the costs incurred to set up the drilling service (i.e., the mobilization activities) may be capitalized as an asset in accordance with the new contract cost provisions in ASC 340-40 if the criteria are met. Further, the drilling contractor would not begin fulfillment of the contract with the well operator until the mobilization activity is completed and the drilling activity commences. Also, any payments received during the mobilization activity would be recognized as a contract liability (deferred revenue) and only recognized as the contractor satisfies its obligations (i.e., performs the drilling service) for its customer (the well operator).

Thinking It Through

Contractors would also have to consider any demobilization provisions in a contract with the customer and determine whether demobilization is a fulfillment activity or a promise to transfer a good or service to the customer. Although mobilization and demobilization are similar activities, the nature of the contractor's promise in demobilization may differ from that in mobilization. Contractors may want to consider whether some activities in demobilization are necessary before control and use of the wellhead are transferred to the operator.

On the other hand, if an activity such as mobilization is a promise to deliver a service to the operator, a contractor must consider whether it is a distinct performance obligation and meets both criteria in ASC 606-10-25-19 for separate revenue recognition:

- The "service is capable of being distinct" (i.e., the operator can benefit from the service on its own or together with other resources that are readily available).
- The "service is distinct within the context of the contract" (i.e., the promise to deliver the service "is separately identifiable from other promises in the contract").

If mobilization is a promise to deliver a service to the well operator, the contractor would begin fulfilling its promise to the operator upon the start of the mobilization efforts. Therefore, the contractor would begin to recognize revenue when mobilization begins (rather than when drilling begins).

Thinking It Through

A drilling contractor should carefully consider whether the efforts involved in the mobilization represent an activity (i.e., a setup activity) or a service that provides a benefit to the customer. If the mobilization efforts satisfy a promise to the customer by delivering a service, the drilling contractor must determine whether that mobilization service is separable from the drilling service. In many cases, the drilling contractor will conclude that mobilization of a drilling rig does not result in a separate benefit for well operators and that the activity is thus incapable of being distinct. However, when that conclusion is inappropriate, contractors will need to determine whether mobilization is (1) both separately identifiable in the contract and distinct in the context of the contract, and thus a distinct performance obligation, or (2) a single service delivery in combination with the drilling operations.

Recognizing Revenue When (or as) Performance Obligations Are Satisfied

Under the ASU, a drilling contractor is likely to conclude that its performance obligation for drilling services in a daywork or other drilling contract is satisfied over time because the contractor's performance creates or enhances an asset (e.g., the oil well) that the customer controls as the asset is created or enhanced. That is, such a performance obligation would meet one of the criteria in ASC 606-10-25-27 to be satisfied over time. Therefore, in such cases, a drilling contractor would recognize revenue by measuring progress toward satisfying the performance obligation in a manner that best depicts the transfer of goods or services to the customer.

A drilling contractor should always select the method that most appropriately depicts its progress toward completion. However, certain types of pricing provisions in a drilling contract may warrant a careful examination of the measure of progress to be used. Consider a two-year offshore drilling contract whose initial day rate of \$500,000 increases by a fixed increment of \$50,000 in each semiannual period. In contemplating the appropriate measure of progress that best depicts the transfer of its service, the contractor in this example may consider the following:

- *Output measure of progress (e.g., time, days drilled)* — As it performs, the contractor could potentially recognize an amount of revenue equivalent to the total transaction price (determined under step 3 of the new revenue model) divided by the total number of days over which services are expected to be delivered. Days during which mobilization and other activities are to be performed may be included in that calculation depending on the conclusions the contractor reaches when identifying the contract's performance obligations. A fixed day rate that increases twice per year by a fixed amount of \$50,000 could be factored into the calculation of the total transaction price and recognized on a straight-line basis over the tenor of the contract (i.e., at an equal, blended amount for each day of contract delivery).
- *Input measure of progress (e.g., costs incurred)* — The contractor may recognize as revenue a percentage of the total transaction price, calculated as a ratio of the costs of drilling for the period (e.g., labor and fuel costs) to the total costs to be incurred to deliver the contract. Again, pricing that increases semiannually by a fixed rate of \$50,000 could be factored into the calculation of the total transaction price. Revenue could be recognized, for example, in increasing amounts over the tenor of the contract if costs are expected to rise as the contract is delivered. This method would be affected by whether the contractor concludes that the mobilization efforts represent (1) a fulfillment activity or (2) all or part of a performance obligation. If the mobilization efforts represent a promise to deliver a service (all or part of a performance obligation), the costs incurred would be included in the cost-to-cost measure of progress. Otherwise, if the efforts represent a fulfillment activity, the costs would be considered set-up costs, which would be capitalized as an asset if they meet certain criteria.

Sales of Mineral Interests and Production Payments

ASU 2014-09 governs the amount, timing, and recognition of gains and losses from the sale of fixed assets and real property. (See Deloitte's July 2, 2014, [Heads Up](#) for additional considerations related to the accounting for real estate sales under the new revenue standard.) However, conveyances of mineral interests and O&G properties are outside the ASU's scope. Therefore, the industry guidance in ASC 932-360 remains in effect and, for example, an O&G entity's sale and retention of its operating and nonoperating interests in a well, respectively, would continue to be accounted for under ASC 932. However, that same entity's sale of its drilling equipment on the property would be accounted for in accordance with the ASU.

The ASU is also not expected to have a significant impact on production payments. Under ASC 932, a production payment repayable in cash plus interest out of proceeds from a specific mineral interest is considered to be a financing and not a sale of that mineral interest. However, a volumetric production payment (VPP) that is repaid in a specified amount of commodity lifted from a specific mineral interest and delivered free and clear of all expense associated with that interest's operation reflects a sale of that mineral interest. Currently, ASC 932-360 requires the seller in a VPP to record deferred revenue that is recognized as the commodity is delivered. This guidance is also outside the ASU's scope. Therefore, the accounting for VPPs is not expected to change as a result of the new revenue model.

Disclosures

The ASU requires significantly more disclosures, including additional quantitative and qualitative information that enables “users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers.” The ASU’s disclosure requirements include:

- Presentation or disclosure of revenue and any impairment losses recognized separately from other sources of revenue or impairment losses from other contracts.
- A disaggregation of revenue to “depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors” (the ASU also provides implementation guidance).
- Information about contract assets and liabilities (including changes in those balances) and the amount of revenue recognized in the current period that was previously recognized as a contract liability and the amount of revenue recognized in the current period that is related to performance obligations satisfied in prior periods.
- Information about performance obligations (e.g., types of goods or services, significant payment terms, typical timing of satisfying obligations, and other provisions).
- Information about an entity’s transaction price allocated to the remaining performance obligations, including (in certain circumstances) the “aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied)” and when the entity expects to recognize that amount as revenue.
- A description of the significant judgments, and changes in those judgments, that affect the amount and timing of revenue recognition (including information about the timing of satisfaction of performance obligations, the determination of the transaction price, and the allocation of the transaction price to performance obligations).
- Information about an entity’s accounting for costs to obtain or fulfill a contract (including account balances and amortization methods).
- Information about the policy decisions (i.e., whether the entity used the practical expedients for significant financing components and contract costs allowed by the ASU).

The ASU requires entities, on an interim basis, to disclose information required under ASC 270 as well as to provide disclosures similar to the annual disclosures (described above) about (1) the disaggregation of revenue, (2) contract asset and liability balances and significant changes in those balances since the previous period-end, and (3) information about the remaining performance obligations.

Effective Date and Transition

The FASB issued ASU 2015-14, which defers the effective date of the new revenue standard, ASU 2014-09, by one year for all entities and permits early adoption as of the original effective dates. For public business entities, the standard is effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2017.

The effective date for nonpublic entities is annual reporting periods beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 15, 2019. Nonpublic entities may also elect to apply the ASU as of any of the following:

- Annual periods beginning after December 15, 2016, including interim reporting periods.
- Annual periods beginning after December 15, 2016, and interim reporting periods with annual reporting periods beginning one year after the annual reporting period in which the new standard is initially applied.

Entities have the option of using either a full retrospective or a modified approach to adopt the guidance in the ASU:

- *Full retrospective application* — Retrospective application would take into account the requirements in ASC 250 (with certain practical expedients). Under this approach, entities would need to reevaluate their contracts from inception to determine the income recognition pattern that best depicts the transfer of goods and services. Further, for comparative financial statement purposes, public entities with a calendar year-end would be required to present income under the new revenue model beginning on January 1, 2016.

The SEC staff in the Division of Corporation Finance (the “Division”) has indicated that it would not object if the basis that a registrant uses to reflect its adoption of the new revenue standard in selected financial data (as required by Regulation S-K, Item 301) is the same as the basis that it uses to adopt the new revenue standard in its financial statements. If a registrant presents less than five years on the basis of the new revenue standard, it would need to disclose the method it used and that the prior years in the selected financial data disclosure are not comparable. See Deloitte’s September 12, 2014, [journal entry](#) for more information.⁷

- **Modified retrospective application** — Under the modified approach, an entity recognizes “the cumulative effect of initially applying [the ASU] as an adjustment to the opening balance of retained earnings . . . of the annual reporting period that includes the date of initial application” (revenue in periods presented in the financial statements before that date is reported under guidance in effect before the change). Under the modified approach, the guidance in the ASU is only applied to existing contracts (those for which the entity has remaining performance obligations) as of, and new contracts after, the date of initial application. The ASU is not applied to contracts that were completed before the effective date (i.e., an entity has no remaining performance obligations to fulfill). Entities that elect the modified approach must disclose an explanation of the impact of adopting the ASU, including the financial statement line items and respective amounts directly affected by the standard’s application. The following chart illustrates the application of the ASU and legacy GAAP under the modified approach for a public company with a calendar year-end:

	2018	2017	2016
Initial Application Year	Current Year	Prior Year	Prior Year 2
New contracts	New ASU		
Existing contracts	New ASU + cumulative catch-up	Legacy GAAP	Legacy GAAP
Completed contracts		Legacy GAAP	Legacy GAAP

Thinking It Through

The modified transition approach provides entities relief from having to restate and present comparable prior-year financial statement information; however, entities will still need to evaluate existing contracts as of the date of initial adoption under the ASU to determine whether a cumulative adjustment is necessary. Therefore, entities may want to begin considering the typical nature and duration of their contracts to understand the impact of applying the ASU and determine the transition approach that is practical to apply and most beneficial to financial statement users.

SAB Topic 11.M Considerations

SAB Topic 11.M provides disclosure requirements for those accounting standards not yet adopted. Specifically, when an accounting standard has been issued but need not be adopted until some future date, a registrant should include disclosure of the impact that the recently issued accounting standard will have on the financial position and results of operations of the registrant when such standard is adopted in a future period. The SEC staff believes that this disclosure guidance applies to every issued accounting standard not yet adopted by the registrant unless the standard’s impact on the registrant’s financial position and results of operations is not expected to be material.

At the 2015 AICPA Conference on Current SEC and PCAOB Developments, the SEC staff weighed in on the SAB Topic 11.M disclosure requirements specific to the new revenue recognition standard. While acknowledging that registrants may not have fully evaluated the implications of the new revenue recognition standard, the staff provided a reminder that SAB Topic 11.M requires registrants to disclose their conclusions to date regarding the impact of the new revenue standard, such as the planned adoption date. The staff expects the level of disclosures to increase as the effective date of the new revenue standard approaches.

⁷ At the 2014 AICPA Conference on Current SEC and PCAOB Developments, the Division staff noted that it will accept less than five years of revenue presented on the basis of the new revenue standard in selected financial data (i.e., it will not require a registrant to retrospectively adjust the last two years). In doing so, the staff is encouraging registrants to use the full retrospective method of adoption because that method will yield information that is more helpful to financial statement users.

Thinking It Through

Given the ongoing standard setting related to implementation of the new revenue standard and the number of outstanding implementation issues being addressed by the industry, we would not expect O&G entities to be in a position to provide specific information about the effects of adoption in their SAB Topic 11.M disclosures in 2015 Forms 10-K. Regulators and others are generally aware of the work being done by the industry task forces (including progress of the task forces), and we expect that they will accept limited SAB Topic 11.M disclosures given the uncertainty about implementation that still exists.



Section 5

Overview of the New Leases Model

Background

After almost a decade, the FASB and IASB are nearing the end of their journey toward enhancing lease accounting: the IASB issued its final standard, IFRS 16, on January 13, 2016, and the FASB is expected to issue its final ASU shortly (i.e., in February 2016). One of the primary objectives of the leases project is to address the current off-balance-sheet financing concerns related to a lessee's operating leases. While developing an approach that would require all operating leases to be recorded on the balance sheet may seem like a simple task, the numerous EDs issued by the boards, along with years of redeliberations, have proved that it has been anything but easy. The boards have had to grapple with questions such as (1) whether an arrangement is a service or a lease, (2) what amounts should be initially recorded on the lessee's balance sheet for the arrangement, (3) how to subsequently account for the amounts recorded (a point on which the FASB and IASB were unable to converge), and (4) how to perform these assessments in a cost-effective manner.

In addition, the boards have addressed other concerns related to the current almost-40-year-old leases model. For example, the FASB is proposing to eliminate the bright lines currently in U.S. GAAP for determining lease classification, and both boards are proposing that lessors provide additional transparency into their exposure to the changes in value of their residual assets and how they manage that exposure.

The following discussion is based on our understanding of the deliberations to date and our expectations of the content of the final standard. As of the date of this publication, the final U.S. GAAP standard had not been issued. Therefore, some of the content herein may be subject to change. In addition, we expect the O&G industry to address a variety of implementation issues once the final standard is issued, and some of the thinking included below may be affected.

Key Provisions

Scope

The scope of the lease accounting guidance would not be restricted to leases of property, plant, and equipment, as it is today. Rather, the scope of the new guidance would include all leases of assets except (1) leases of intangible assets, (2) leases to explore for or use minerals, oil, natural gas, and similar nonregenerative resources, and (3) leases of biological assets. As a result, assets currently accounted for as inventory, such as spare parts and supplies, may now be subject to a lease under the new guidance.

Thinking It Through

We understand through recent discussions with the FASB staff that the scope of the FASB guidance may be changed to exclude inventory and CWIP. This reconsideration occurred late in the process as the FASB received unsolicited feedback about revising the scope, particularly in the context of build-to-suit arrangements. Interested parties should refer to the final standard for final resolution of this matter.

Definition of a Lease

The new standard will define a lease as "a contract, or part of a contract, that conveys the right to control the use [of] an identified asset (the underlying asset) for a period of time in exchange for consideration." When determining whether a contract contains a lease under the new standard, entities should assess whether (1) performance of the contract depends on the use of an identified asset and (2) the customer obtains the right to control the use of the identified asset for a particular period.

The concept of an identified asset is mostly consistent with that in current U.S. GAAP and IFRSs. Under this concept, a leased asset must be specifically identifiable either explicitly (e.g., by a named generating asset) or implicitly (e.g., the asset is the only one available to meet the requirements of the contract). The evaluation should take into account any substantive rights of the supplier to substitute the underlying asset throughout the period of use. Substitution rights would be considered substantive if the supplier has the practical ability to substitute alternative assets (i.e., the customer cannot prevent the supplier from doing so and alternative assets are readily available to, or can be quickly sourced by, the supplier) and the supplier would benefit economically from the substitution. A specified asset could be a physically distinct portion of a larger asset (e.g., one floor of a building). However, a capacity portion of a larger asset that is not physically distinct (e.g., a percentage of a natural gas pipeline's or storage facility's total capacity) would generally not be a specified asset unless that capacity portion reflects substantially all of the larger asset's overall capacity.

Thinking It Through

The requirement that substitution would provide an economic benefit to the supplier is a higher threshold than that in current U.S. GAAP. Accordingly, we expect more arrangements to be subject to lease accounting by virtue of the new standard's changes to the evaluation of substitution rights.

With regard to a customer's right to control the use of the identified asset, the definition of a lease under the new standard will represent a significant change from current guidance. Under existing U.S. GAAP, taking substantially all of the outputs of an identified asset is considered sufficiently representative of when an agreement transfers the economics of an asset to the customer, and thus of the customer's right to control the use of that asset (e.g., a gas supply agreement in which the customer purchases substantially all of the outputs of a gas production and treatment facility). In contrast, the new standard will align the assessment of whether a contract provides the customer the right to control the use of the specified asset with the concept of control developed as part of the boards' new revenue standard.¹ Accordingly, a contract evaluated under the new standard would be deemed to convey the right to control the use of an identified asset if the customer has the right to direct, and obtain substantially all of the economic benefits from, the use of that asset. The right to direct the use of the specified asset would take into account whether the customer has the right to determine — or predetermine — how and for what purpose the asset is used. Economic benefits from the use of the specified asset would include its primary products and by-products or other economic benefit that the customer can realize in a transaction with a third party (e.g., natural gas liquids in wet gas).

Thinking It Through

The transition provisions in the new lease accounting guidance will provide a package of reliefs that entities may elect as a whole as a means of reducing the costs of implementing the new standard. One of the practical expedients is a grandfathering provision under which an entity would not be required to reassess whether an existing contract contains or constitutes a lease as defined by the new guidance. While we expect that the transition relief will make adoption of the new standard much easier (since an entity would not have to revisit older lease contracts and related documentation to reevaluate whether those contracts meet the definition of a lease under the new requirements), it is important to note that this transition relief does not alleviate an entity's obligation to address any errors that may have resulted from the misapplication of past accounting. For example, because there is less tension under current U.S. GAAP regarding whether a contract is an operating lease or a service arrangement, O&G entities may not have appropriately assessed whether the arrangement met the definition of a lease under ASC 840 (formerly EITF Issue No. 01-08). If an entity improperly accounted for an arrangement as a service rather than a lease, it would be required to make the appropriate corrections to its current and past financial statements.

¹ ASU 2014-09, *Revenue From Contracts With Customers* (codified in ASC 606) defines control as "the ability to direct the use of, and obtain substantially all of the remaining benefits from, the asset." This differs from the concept of control in the consolidation guidance, which requires the design of the entity to be considered in the evaluation of control.

Implications for O&G Entities

Agreements that O&G entities enter into are frequently customized and, especially in oilfield services arrangements, include service and other components critical to completing the contract. While the proposed definition of a lease is similar to the definition now in use in some respects, it is different in others. In particular, the concept of the customer's right to control the use of an identified asset has been modified to achieve consistency with the new revenue standard.

Accordingly, O&G entities would need to assess many current service and lease contracts under the new leases standard to determine whether such agreements meet, or have components that meet, the new definition of a lease. Under the standard, when determining whether a contract contains a lease, O&G entities would assess whether (1) performance of the contract depends on the use of an identified asset and (2) the customer obtains the right to control the use of the identified asset for a particular period.

Drilling Contracts

Given the breadth of contract structures used in oil and gas exploration and production, it is likely that O&G entities will need to increase their scrutiny of both onshore and offshore drilling contracts to determine whether such contracts are (or contain) leases under the new standard. The terms and conditions of drilling contracts are often complex and specifically negotiated, making it challenging for entities to determine the appropriate accounting under the new guidance. The determination of whether a well operator (i.e., a customer in a drilling contract) controls an identified rig in a drilling contract would dictate whether the arrangement is accounted for as a lease on the balance sheet or is treated as an off-balance-sheet service arrangement.

Fulfillment of the Contract Depends on the Use of an Identified Asset

Because of the nature of projects undertaken and the various logistical and technical complexities involved, specific rigs are often explicitly or implicitly identified in the terms of a drilling contract. Drilling contracts may also involve capital upgrade requirements that make it necessary for an independent contractor (i.e., a supplier in a drilling contract) to custom-fit a specific rig to meet an operator's unique drilling program needs. Accordingly, the fulfillment of a drilling contract will often depend on the use of an identified drilling rig.

Right to Direct the Use of the Identified Asset

A well operator has the right to direct the use of a specified drilling rig if it can determine how and for what purpose the asset is used. Further, the extent to which an operator determines how and for what purpose the specified rig is used will depend on whether the drilling contract grants the operator decision-making rights over that asset. Therefore, an operator should (1) identify the decision-making rights that most affect how and for what purpose the rig is used throughout the period of use (i.e., which decision-making rights most affect the economic benefits to be derived from the use of the rig) and (2) determine who controls those rights. If the decisions related to how and for what purpose the rig is used are predetermined (by contract or the nature of the asset), the assessment will focus on whether the operator (1) controls the drilling program or (2) designed the aspects of the rig that are most relevant to how and for what purpose it is used; meeting either of these criteria would be deemed to convey the right to direct the use of the identified asset to the operator.



The decision-making rights that most affect the economic benefits to be derived from a drilling rig are likely to differ depending on the type of drilling contract. The following table discusses decision-making rights that an operator may be granted in various types of drilling contracts and presents our current thinking on whether those rights determine how and for what purpose a specified onshore or offshore rig is used.

Type of Drilling Contract	Operator's Decision-Making Rights	Do the Operator's Decision-Making Rights Determine How and for What Purpose the Drilling Rig is Used?
Turnkey	The contractor retains all risks in drilling the well up to a contractually defined milestone (e.g., casing of the well). The contract specifies where the rig is to drill and the depth of the well. Upon reaching the predetermined milestone, the operator pays the contractor a lump sum and the contractor "turns over the key" of the well to the operator.	No. Decision-making rights that most affect the economic benefits to be derived from the use of the rig, and thus how and for what purpose the rig is used, either have been predetermined in the contract or remain with the contractor. Decisions about where the output is produced (i.e., where the rig will drill) and the quantity of the output produced (i.e., how many feet the rig will drill) have been predetermined in the contract. The contractor retains decision-making rights throughout the period of use about whether and, if so, when the rig will drill/produce output (i.e., the drilling program).
	Same as above, except the operator is required by the relevant regulatory authority to assume responsibility for blowouts, spills, and other risks.	It depends. If the operator is taking on greater risks in the residual asset of the rig (e.g., damage from a blowout), the operator may seek to increase its control over the management of those risks. That is, in return for taking on greater risks in the drilling of the well, the operator may structure the contract to provide more decision-making rights over how and for what purpose the rig is used.
Footage	The operator pays the contractor a contractually specified rate per foot drilled for a well. The contract specifies where the rig is to drill and the depth of the well.	No. Decision-making rights that most affect the economic benefits to be derived from the use of the rig, and thus how and for what purpose the rig is used, either have been predetermined in the contract or remain with the contractor. Decisions about where the output is produced (i.e., where the rig will drill) and the quantity of the output produced (i.e., how many feet the rig will drill) have been predetermined in the contract. The contractor retains decision-making rights throughout the period of use about whether and, if so, when the rig will drill/produce output (i.e., the drilling program).
	The operator pays the contractor a contractually specified rate per foot drilled. Whether and, if so, where and how much to drill within a contractually defined oilfield are determined by the operator. The contractor retains responsibility for operating and maintaining the rig.	Yes. The operator's decision-making rights provide the operator with the right to change, throughout its period of use, whether and, if so, where and how much to drill. These decision-making rights most affect the economic benefits to be derived from the rig and thus determine how and for what purpose the rig is used throughout the operator's period of use. Although operating and maintaining the rig are essential to its efficient use, decisions over those activities do not by themselves most affect how and for what purpose the rig is used; rather, they are <i>subject to</i> the operator's decision-making rights related to how and for what purpose the rig is used.
Daywork	The operator pays the contractor a contractually specified rate per day of drilling. Rates may also be specified for nonworking days or for mobilization. The operator determines specific operating procedures (i.e., drilling program) by which the contractor must strictly abide, including where the rig is to drill, how many feet the rig will drill, and the conditions governing whether and when the rig will drill (e.g., related to weather). The contractor retains responsibility for operating and maintaining the rig.	Yes. The decision-making rights that most affect the economic benefits to be derived from the use of the rig, and thus how and for what purpose the rig is used, have been predetermined in the drilling program, which the contractor does not have the right to change throughout the period of use. Although operating and maintaining the rig are essential to its efficient use, decisions over those activities do not by themselves most affect how and for what purpose the rig is used; rather, they are <i>subject to</i> the operator's decision-making rights related to how and for what purpose the rig is used (i.e., subject to the drilling program).

Other important decision-making rights that affect the economic benefits to be derived from a drilling rig should also be considered in the assessment of whether the operator's decision-making rights most affect how and for what purpose the asset is used. Such additional rights may include, but are not limited to, the well operator's decision-making right to determine the entity operating the rig.

In all scenarios, the operator would need to evaluate on the basis of the specific facts and circumstances whether it has the right to determine how and for what purpose a specified drilling rig is used, and thus, the right to direct the use of the asset. The operator would need to use judgment when performing this evaluation.

Transportation and Storage Contracts

Existing contract structures to transport or store oil and gas products would need to be evaluated in light of the new guidance's definition of a lease. Underlying assets that may be used to store or transport those products include the following:

- *Pipelines* — Current guidance does not preclude a percentage of a pipeline's transport or storage capacity from being subject to a lease. Under the new leases standard, however, a capacity portion of a larger asset that is not physically distinct (e.g., a percentage of a pipeline) would generally not be a specified asset. Therefore, a pipeline contract that does not provide for the use of substantially all of the capacity would be outside the scope of the standard. Because pipeline contracts can be structured differently (e.g., on the basis of a percentage of benefits), companies would have to review them to determine the appropriate accounting.
- *Vessels* — Waterborne transportation of liquid and gas products is addressed in many types of contracts, such as bareboat, time, and voyage charters. Such shipping contracts can take various forms, and their terms can differ significantly. For instance, bareboat charters may involve a specific vessel or a physically distinct portion of a vessel; time charters, on the other hand, may allow for substantive substitution of the vessel. In addition, the ability of the charterer-in to direct the use of a vessel may vary in a time or voyage charter, in which the vessel is operated by the charterer-out's crew. However, for charters that may or not be determined to contain a lease depending on the use of a specified vessel, the final standard is expected to include implementation guidance indicating that a time charter contains a lease and a voyage charter does not. Because contracts for the right to use a vessel could be considered to constitute or contain leases under the new guidance, O&G marketing entities would need to evaluate such contracts to determine the appropriate accounting.
- *Railcars* — The use of railcars to transport or store oil and gas products (e.g., to transport light sweet crude from the Bakken shale formation to refiners on the East Coast of the United States) will remain important as infrastructure in the United States, Canada, and other countries continues to develop. Contracts involving railcars may be considered leases under the new guidance but may also constitute service agreements. This determination would depend on the extent of the freight supplier's (1) involvement in directing the use of the railcars and (2) ability to substitute identified railcars under the contract. The appropriate accounting for such contracts will be heavily based on their specific terms. The final standard is expected to contain examples in its implementation guidance to help O&G entities apply the definition of a lease to contracts for railcars.

Lessee Accounting Model

Initial Measurement

Under the proposed lessee accounting model, the initial measurement of a lease would be based on a right-of-use (ROU) asset approach. Under this approach, a lessee would recognize an asset for its right to use the underlying asset over the lease term and a liability for the corresponding lease obligation, measured at the present value of the future lease payments (excluding variable payments). The initial measurement of the ROU asset would include (1) initial direct costs² (e.g., legal fees, consultant fees, commissions paid) that are directly attributable to negotiating and arranging the lease, (2) lease payments to the lessor before or at the commencement of the lease, and (3) lease incentives (i.e., receipts from the lessor would reduce the ROU asset).

In addition to those payments that are directly specified in a lease agreement and fixed over the lease term, fixed payments include variable lease payments that are considered in-substance fixed payments (e.g., when a variable payment includes a floor or a minimum amount that would be due, such floor or minimum amount would essentially be an in-substance fixed payment). However, the fact that a variable lease payment is virtually certain (e.g., a variable payment for highly predictable output under a renewable power purchase agreement) does not make the payment in-substance fixed.

² The proposed model defines initial direct costs as those incremental costs "that an entity would not have incurred if the lease had not been obtained (executed)."

Subsequent Measurement

Although the FASB and IASB agreed on the lessee's initial measurement of a lease, they differed on the lessee's subsequent measurement of a lease as follows:

- *Dual-model approach (FASB)* — Lessees would classify a lease as either a finance lease or an operating lease by using classification criteria similar to those in IAS 17. This distinction would drive timing of expense in the income statement, as discussed below.
- *Single-model approach (IASB)* — Lease classification would be eliminated for lessees, and all leases would be accounted for in a manner consistent with the accounting for finance leases under the FASB's approach.

Thinking It Through

The FASB supports the dual-model approach because it believes that all leases are not equal; in the FASB's view, some leases are more akin to an alternate form of financing for the purchase of an asset while other leases are truly the renting of the underlying property. In contrast, the IASB believes that the single-model approach (i.e., one that eliminates lease classification) has greater conceptual merit and would reduce complexity.

Under the FASB's dual-model approach, a lessee would classify the lease on the basis of whether the lease transfers substantially all of the risks and rewards incidental to ownership of the underlying asset to the lessee. Therefore, a lease would be classified as a finance lease if any of the following criteria are met at the commencement of the lease:³

- "The lease transfers ownership of the underlying asset to the lessee by the end of the lease term."
- It is reasonably certain that a lessee will "exercise an option to purchase the underlying asset."
- "The lease term is for a major part of the remaining economic life of the underlying asset."⁴
- "The sum of the present value of the lease payments [including residual value guarantees] amounts to substantially all of the fair value of the leased asset."
- "The underlying asset is of such a specialized nature that it is expected to have no alternative use to the lessor at the end of the lease term."

An entity would determine the lease classification at lease commencement and would not be required to reassess its classification unless the lease is subsequently modified and accounted for as a new lease.

Thinking It Through

These criteria are similar to those that exist today in IAS 17, and they are similar but not identical to the requirements under current U.S. GAAP. As a result, a lease that would have been classified as an operating lease may be classified as a finance lease under the new classification criteria (and vice versa). In addition, under the new guidance, a lessee would assess land and other elements separately unless the accounting impact for the land would be insignificant. Although this approach is consistent with that of IFRSs, it differs from the lease accounting guidance under current U.S. GAAP, which provides that if a lease does not transfer ownership of the real estate or contain a bargain purchase option, a lessee would evaluate the lease classification for the land and other elements as a single unit unless the fair value of the land is 25 percent or more of the total fair value of the leased property at lease inception. The proposed change from current U.S. GAAP may result in more bifurcation of real estate leases into separate elements and may affect the allocation of the lease payments to the various elements.

³ Quoted text is from [FASB Agenda Paper 268](#).

⁴ As noted on the [project update page](#) of the FASB's Web site, the Board decided to provide an exception to this lease classification test for leases that commence "at or near the end" of the underlying asset's economic life. Further, the Board decided that "the final leases standard should include implementation guidance that one reasonable approach to determining the applicability of this exception would be to conclude that a lease that commences in the final 25 percent of an asset's economic life is 'at or near the end' of the underlying asset's economic life."

Under either a finance lease or an operating lease, the lessee would amortize the lease liability by using the applicable discount rate. Accordingly, the lease liability would be measured at the present value of the remaining lease payments, which the lessee would calculate by discounting the payments at the rate established at lease commencement.

The ROU asset of a finance lease would be amortized in the same manner as other nonfinancial assets; that is, it would generally be depreciated on a straight-line basis unless another systematic method would be appropriate. Since interest expense is higher in the early years of a financing liability, the combination of interest expense and ROU amortization will result in a front-loaded expense profile for finance leases. Entities would separately present the interest and amortization expenses in the income statement.

The ROU asset of an operating lease would be calculated as the lease liability, adjusted by (1) any accrued or prepaid rents, (2) unamortized initial direct costs and lease incentives, and (3) impairments of the ROU asset. This results in a periodic lease expense for operating leases equal to the lease payments made over the lease term, recognized on a straight-line basis unless another systematic method is more appropriate.

Regardless of classification, the ROU asset would be subject to impairment testing in a manner similar to how other long-lived assets are tested for impairment. If the ROU asset for a lease classified as an operating lease is impaired, the lessee would amortize the remaining ROU asset evenly over the remaining lease term. Therefore, in periods after the impairment, the recognized lease expense would comprise the ROU amortization and lease liability accretion for the period (i.e., the periodic lease expense would no longer be recorded on a straight-line lease basis).

Lessor Accounting

In contrast to its approach to developing a new lessee model, the FASB decided to make only minor modifications to the current lessor model. Under the new standard, a lessor would classify the lease as a sales-type lease, direct financing lease, or operating lease by using the classification criteria previously discussed for lessees:

- *Sales-type lease* — A lease in which the lessee effectively gains control of the underlying asset during the lease term. The lessor would derecognize the underlying asset and recognize a lease receivable and unguaranteed residual asset. Any resulting selling profit or loss would be recognized at lease commencement. Initial direct costs would be recognized as an expense at lease commencement unless there is no selling profit or loss. In this case, the initial direct costs would be deferred and recognized over the lease term. In addition, the lessor would recognize interest income from the lease over the lease term.
- *Direct financing lease* — A lease in which the lessee does not effectively obtain control of the asset but (1) the present value of the lease payments and any residual value guarantee (which could be provided entirely by a third party or could comprise a lessee guarantee coupled with a third-party guarantee)⁵ represents substantially all of the fair value of the underlying asset and (2) it is probable that the lessor would collect the lease payments and any amounts related to the residual value guarantee. The lessor would derecognize the underlying asset and recognize a lease receivable and unguaranteed residual asset. The lessor's profit, initial direct costs, and interest income would be deferred and amortized into income over the lease term.
- *Operating lease* — A lease in which the lessee does not effectively obtain control of the asset over the lease term because none of the classification criteria are met. Income resulting from an operating lease would be recognized on a straight-line basis unless another systematic basis would be more appropriate. Any initial direct costs (i.e., those that are incremental to the arrangement and would not have been incurred if the lease had not been obtained) are to be deferred and expensed over the lease term in a manner consistent with the way lease income is recognized.

⁵ If the present value of lease payments plus a lessee-provided residual value guarantee represents substantially all of the fair value of the underlying asset, the lessor would classify the lease as a sales-type lease.

Thinking It Through

While the FASB aligned lessor accounting with the new revenue guidance in ASC 606 in many respects, there is an important distinction that may affect lessors operating in the O&G sector. Under ASC 606, variable revenues are estimated and included in the transaction price, subject to a constraint. In contrast, under the new leases standard, variable lease payments would generally be excluded from the determination of a lessor's lease receivable. It is unclear whether the new standard will include guidance on accounting for arrangements that have a significant "variable-only" payment stream. There is a possibility that direct financing leases or sales-type leases may result in inception losses for the lessor if the lease receivable plus the unguaranteed residual asset is less than the net carrying value of the asset being leased. O&G entities should evaluate the final ASU once issued to see how the final provisions may affect these types of arrangements.

Effective Date and Transition

The new guidance would be effective for public business entities for annual periods beginning after December 15, 2018 (i.e., calendar periods beginning on January 1, 2019), and interim periods therein. For all other entities, the standard would be effective for annual periods beginning after December 15, 2019 (i.e., calendar periods beginning on January 1, 2020), and interim periods thereafter. Early adoption would be permitted for all entities. Entities would be required to apply a modified retrospective method of adoption, and the FASB has proposed several forms of transition relief that should significantly ease the burden of adoption.

Thinking It Through

Under U.S. GAAP, entities may adopt the new leases standard before they adopt the new revenue guidance (even though the new revenue standard has an earlier required effective date). It is our understanding that those early adopters would be expected to apply the relevant guidance in the new revenue guidance to the extent that it affects their lease accounting. All other aspects of the new revenue standard would wait until full adoption of that standard.

Next Steps

The FASB is expected to issue its final ASU introducing the new leases model (to be codified as ASC 842) in February 2016. The IASB issued its final leases standard, IFRS 16, on January 13, 2016. For more information about IFRS 16, see Deloitte Touche Tohmatsu Limited's January 13, 2016, *IFRS in Focus*. Keep an eye out for our [Heads Up](#) publication on leases that will be issued shortly after the issuance of the FASB's final standard.



Section 6 SEC Update

Activities Related to Requirements Under the Dodd-Frank Act

The passage of the Dodd-Frank Act in July 2010 brought a number of key reforms to the U.S. financial system. The Dodd-Frank Act requires the SEC to perform certain actions, such as adopting rules or conducting studies. The discussion below summarizes Dodd-Frank Act activity that has occurred since the last edition of this publication.

SEC and Other Government Agencies Issue Final Rule on Credit Risk Retention

On October 22, 2014, the SEC and five other federal agencies adopted a [final rule](#) that requires securitizers, under certain conditions, to retain a portion of the credit risks associated with the assets collateralizing an asset-backed security (ABS). The final rule was issued in response to a mandate of Section 941 of the Dodd-Frank Act, which added new credit risk retention requirements to Section 15G of the Exchange Act.

The final rule addresses what some believed to be a critical weakness in the securitization market that led to the financial crisis — namely, that certain meaningful risks need to be retained to ensure that securitizers have the incentives to monitor the quality of the securities. Therefore, under the final rule, securitizers are:

- Required to retain no less than 5 percent of the credit risk of assets collateralizing an ABS.
- Prohibited from hedging or transferring the credit risk they are required to retain.

In addition, the final rule permits securitizers to select a form of risk retention obligation from a menu of specified options. The options available include (1) an eligible vertical interest, (2) an eligible horizontal residual interest, or (3) a combination of both when the combined interest is no less than 5 percent of the fair value of all ABSs issued. ABSs that are collateralized solely by “qualified residential mortgages” (QRMs) are exempt from the risk retention requirements. The final rule alters the definition of a QRM to align it with the Consumer Financial Protection Bureau’s definition of a “qualified mortgage.” The final rule became effective on February 23, 2015.

SEC Proposes Hedging Disclosure Requirements

On February 9, 2015, the SEC issued a [proposed rule](#) that would enhance corporate governance by requiring registrants to disclose employee and director information that may affect shareholders’ interests. Specifically, the proposal, which was issued in response to a requirement in Section 955 of the Dodd-Frank Act, would require a registrant to disclose, in a proxy or information statement, whether “the registrant permits any employees (including officers) or directors of the registrant, or any of their designees, to purchase financial instruments (including prepaid variable forward contracts, equity swaps, collars, and exchange funds) or otherwise engage in transactions that are designed to or have the effect of hedging or offsetting any decrease in the market value of equity securities.” Comments on the proposed rule were due by April 20, 2015.

SEC Proposes Rule on Pay Versus Performance

On April 29, 2015, the SEC issued a [proposed rule](#) that would amend Regulation S-K, Item 402, to implement a mandate under the Dodd-Frank Act requiring a registrant to disclose the relationship between executive compensation actually paid and the financial performance of the registrant. The proposal is intended to improve shareholders’ ability to objectively assess the link between executive compensation and company performance. In the proposal, the SEC has requested comments on 64 questions. Under the proposal, a company would be required to disclose, in a new table, the following information for its last five fiscal years:

- Executive compensation actually paid to its principal executive officer (PEO), which would be the total compensation amount already disclosed in the summary compensation table required in the proxy statement, adjusted for certain amounts that were not actually paid (e.g., for pensions and equity awards).

- The average compensation actually paid to the remaining named executive officers identified in the summary compensation table.
- Total executive compensation reported for the principal executive in the summary compensation table, and the average of amounts reported for the other named executive officers.
- Total shareholder return (TSR) of the company on an annual basis.
- TSR, on an annual basis, of companies in the same peer group used in the company's stock performance graph or its compensation discussion and analysis.

Comments on the proposal were due by July 6, 2015.

See Deloitte's May 29, 2015, [Heads Up](#) for additional information.

Cross-Border Security-Based Swaps

On April 29, 2015, the SEC issued a [proposed rule](#) on cross-border security-based swap transactions related to activity in the United States. As noted in an SEC [press release](#), the proposed rule would "require a non-U.S. company that uses U.S. personnel to arrange, negotiate, or execute a transaction in connection with its dealing activity to include that transaction in determining whether it is required to register as a security-based swap dealer." According to SEC Chair Mary Jo White, the proposal would "help ensure that both U.S. and non-U.S. dealers are subject to [the SEC's] registration, reporting, public dissemination and business conduct requirements when they engage in security-based swap activity in the United States, resulting in increased transparency and enhanced stability and oversight." Comments on the proposal were due by July 13, 2015.

SEC and CFTC Issue Interpretation on Forward Contracts With Volumetric Optionality

On May 12, 2015, the SEC and the Commodity Futures Trading Commission (CFTC) jointly issued an [interpretive release](#) that clarifies the CFTC's "interpretation of when an agreement, contract, or transaction with embedded volumetric optionality would be considered a forward contract." Issued in response to a Dodd-Frank Act mandate and comments from market participants, the interpretive release became effective on May 18, 2015.

New Proposed Clawback Requirements

On July 1, 2015, the SEC issued a [proposed rule](#) that would require companies to adopt "clawback" policies on executive compensation. Specifically, the proposal, which was released in response to a mandate in Section 954 of the Dodd-Frank Act, "would direct the national securities exchanges and national securities associations to establish listing standards that would require each issuer to develop and implement a policy providing for the recovery, under certain circumstances, of incentive-based compensation based on financial information required to be reported under the securities laws that is received by current or former executive officers, and require the disclosure of the policy." This proposal marks the completion of the SEC's issuance of proposed executive compensation rules under the Dodd-Frank Act. Comments on the proposed rule were due on September 14, 2015.

SEC Reproposes Rules Requiring Disclosures by Resource Extraction Issuers

On December 11, 2015, the SEC voted 3–1 to repropose [rules](#)¹ (collectively, the "rules" or the "proposal") mandated under the Dodd-Frank Act that would require resource extraction issuers to disclose certain payments made to a foreign government or the federal government. The rules are designed to improve transparency "to help combat global corruption and empower citizens of resource-rich countries to hold their governments accountable for the wealth generated by those resources." The rules would apply to a domestic or foreign issuer that (1) is required to file an annual report with the SEC under the Exchange Act and (2) engages in the commercial development of oil, natural gas, or minerals.²

¹ SEC Release No. 34-76620, *Disclosure of Payments by Resource Extraction Issuers*.

² Under the proposal, commercial development of oil, natural gas, or minerals refers to "exploration, extraction, processing, and export of oil, natural gas, or minerals, or the acquisition of a license for any such activity."

Under the rules, such an entity would be required to include, as an exhibit to its annual report on Form SD, information about payments made during the fiscal year by the entity, its subsidiaries, and entities under its control to a foreign government (including a foreign subnational government) or the federal government for the purpose of the commercial development of oil, natural gas, or minerals. The entity would also be required to tag this information by using an XBRL format. The proposal defines a “payment” as an amount paid that:

- (i) Is made to further the commercial development of oil, natural gas, or minerals;
- (ii) Is not de minimis³; and
- (iii) Is one or more of the following:
 - (A) Taxes;
 - (B) Royalties;
 - (C) Fees;
 - (D) Production entitlements;
 - (E) Bonuses;
 - (F) Dividends; and
 - (G) Payments for infrastructure improvements.

Thinking It Through

Certain disclosures about payments required under the proposal would be disaggregated by project, which is defined as “operational activities that are governed by a single contract, license, lease, concession, or similar legal agreement, which form the basis for payment liabilities with a government.” The proposal further states that agreements “that are both operationally and geographically interconnected may be treated by the resource extraction issuer as a single project.”

One required disclosure would be “the subnational geographic location of the project,” which “must be sufficiently detailed to permit a reasonable user of the information to identify the project’s specific, subnational, geographic location.” The dissenting commissioner feared that this “reasonable user of the information” standard could be interpreted as a new legal standard that differs from the “reasonable investor” standard traditionally used in federal securities laws.

Extraction issuers would be required to file Form SD with the SEC no later than 150 days after their fiscal year-end. If adopted as proposed, the rules would become effective for each issuer for fiscal years ending no earlier than one year after the effective date of the final rules.

The proposal solicits comments on most aspects of its provisions. Initial comments on the proposal were due by January 25, 2016. Reply comments, which may respond only to issues raised in the initial comment period, will be due by February 16, 2016.

For more information about the proposal, see the SEC’s December 11, 2015, [press release](#).

³ The proposed rule defines “not de minimis,” in part, as “any payment, whether made as a single payment or a series of related payments, which equals or exceeds \$100,000, or its equivalent in the issuer’s reporting currency, during the fiscal year covered by . . . Form SD.”

Thinking It Through

The SEC originally adopted rules to implement the Dodd-Frank mandate in 2012; however, after being challenged, those rules were vacated in 2013 by the U.S. District Court for the District of Columbia. In response to the court ruling and stakeholder concerns, the repropose rules would allow issuers to seek exemptive relief from the SEC on a case-by-case basis (e.g., for situations in which the rules conflict with other countries' prohibitions against disclosing such information). In addition, the repropose rules would allow an issuer to satisfy its disclosure obligation by including as an exhibit to Form SD a "report complying with the reporting requirements of any alternative reporting regime that are deemed by [the SEC] to be substantially similar" to the rules' requirements (e.g., reports filed in a foreign jurisdiction or that meet the requirements of the U.S. Extractive Industries Transparency Initiative).

SEC Issues Final Rule on Pay Ratio Disclosure

On June 4, 2015, the SEC staff released an [analysis](#) of the Commission's September 2013 proposed rule on pay ratio disclosures. As explained in the SEC's [final rule](#) issued on August 5, 2015, the analysis, which was developed by the Commission's Division of Economic and Risk Analysis, examines "the potential effects of excluding different percentages of employees from the pay ratio calculation." This analysis was used in the development of the final rule.

Under the final rule, a registrant is required to calculate and disclose (1) the median of the annual total compensation of all of its employees (excluding its PEO), (2) the PEO's annual total compensation, and (3) the ratio of (1) to (2). Starting with



its first full fiscal year beginning on or after January 1, 2017, the registrant will include the disclosures in filings in which executive compensation information is required, such as proxy and information statements, registration statements, and annual reports. Emerging growth companies, smaller reporting companies, foreign private issuers, registered investment companies, and filers under the U.S.-Canadian Multijurisdictional Disclosure System are exempt from the rule's requirements.

In determining median employee compensation under the rule, a registrant generally must consider all of its employees and those of its consolidated subsidiaries, including full-time, part-time, temporary, and seasonal workers, and those working in foreign jurisdictions. Although a registrant can annualize compensation amounts considered for permanent employees who worked only part of the year (e.g., a new hire), it cannot annualize amounts

for seasonal or temporary employees, nor can it make full-time equivalent adjustments for any employee. The rule became effective on October 19, 2015.

For detailed information about the rule, see Deloitte's August 6, 2015, [journal entry](#).

Navigating the Conflict Minerals Rule

There is ongoing legal action against the SEC regarding the constitutionality of certain disclosure requirements in its [final rule](#) on conflict minerals (i.e., tin, tantalum, tungsten, or gold). In April 2014, the D.C. Circuit held that parts of the final rule and of Section 1502 of the Dodd-Frank Act violate the First Amendment to the extent that they require "regulated entities to report to the Commission and to state on their website that any of their products have 'not been found to be "DRC conflict free.'"" Thus, although registrants are still expected to file Form SD and, if applicable, a conflict minerals report (CMR) required by the rule on or before the due date, they are not required to identify any products as having "not been found to be 'DRC conflict free'" or as "DRC conflict undeterminable." Registrants could still elect to identify products as "DRC conflict free"; however, they would be required to obtain an independent private-sector audit (IPSA) in such cases.

On August 18, 2015, the D.C. Circuit upheld its April 2014 ruling that parts of the SEC’s conflict minerals rule and of Section 1502 of the Dodd-Frank Act violate the First Amendment to the extent that they require issuers to disclose that their products have “not been found to be ‘DRC conflict free.’” The D.C. Circuit agreed to review its April 2014 ruling in light of a separate case involving country-of-origin labeling of meat products.

For more information about the SEC’s final rule on conflict minerals and the related legal proceedings, see Deloitte’s August 19, 2015, [journal entry](#).

The Jumpstart Our Business Startups Act

The SEC continues to complete its rulemaking mandates under the JOBS Act.⁴ Below is a summary of JOBS Act activity that has occurred since the last edition of this publication.

Revisions to Registration Requirements

On December 18, 2014, in response to the mandates in Titles V and VI of the JOBS Act, the SEC issued a [proposed rule](#) that would revise the requirements in Section 12(g) of the Exchange Act related to the thresholds for registration, termination of registration, and suspension of reporting. As stated in an SEC [press release](#), the proposal would:

- Amend “Exchange Act Rules 12g-1 through 4 and 12h-3 which govern the procedures relating to registration, termination of registration under Section 12(g), and suspension of reporting obligations under Section 15(d) to reflect the new thresholds established by the JOBS Act.”
- Revise “the rules so that savings and loan holding companies are treated in a similar manner to banks and bank holding companies for the purposes of registration, termination of registration, or suspension of their Exchange Act reporting obligations.”
- Apply “the definition of ‘accredited investor’ in [Regulation D, Rule 501(a),] to determinations as to which record holders are accredited investors for purposes of Exchange Act Section 12(g)(1). The accredited investor determination would be made as of the last day of the fiscal year.”

In addition, the proposal would amend the definition of “held of record” and establish a nonexclusive safe harbor under Exchange Act Section 12(g). Comments on the proposed rule were due by March 2, 2015.

SEC Issues Final Rule to Ease Smaller Companies’ Access to Capital

On March 25, 2015, the SEC issued a [final rule](#) that amends and expands Regulation A, which exempts certain offerings from registration under the Securities Act. The rule implements a mandate in Section 401 of the JOBS Act to ease smaller companies’ access to capital. Under Regulation A before the amendments, a company could offer up to \$5 million of securities in a 12-month period and no more than \$1.5 million of those securities could be offered by the company’s securityholders. Under the new rule, a company can offer and sell up to \$50 million of securities in a 12-month period if it meets specified eligibility, disclosure, and reporting requirements. The rule creates the following two tiers of offerings under Regulation A:

- “Tier 1: annual offering limit of \$20 million, including no more than \$6 million on behalf of selling securityholders that are affiliates of the issuer.”
- “Tier 2: annual offering limit of \$50 million, including no more than \$15 million on behalf of selling securityholders that are affiliates of the issuer.”

⁴ In April 2012, the JOBS Act was signed into law to increase American job creation and economic growth by improving access to the public capital markets for EGCs. The JOBS Act addresses topics such as “crowdfunding” transactions, increases shareholder limits that would require companies to register with the SEC, and provides accommodations to EGCs. See Deloitte’s April 15, 2014, [Heads Up](#) for additional information.

The final rule establishes offering and reporting requirements for issuers under both tiers; however, such requirements are more extensive for Tier 2 issuers, which must provide audited financial statements in their offering documents and file annual, semiannual, and current reports with the SEC. The rule also preserves, “with some modifications, existing provisions regarding issuer eligibility, offering circular contents, testing the waters, and ‘bad actor’ disqualification.”

On June 18, 2015, the SEC staff issued [guidance](#) on its March 2015 amendments to Regulation A. The amendments, as further described above, became effective on June 19, 2015. The SEC staff also issued and revised a number of Compliance and Disclosure Interpretations (C&DIs) to provide additional guidance on Regulation A. Specifically, the staff added questions 182.01 through 182.11 under the Securities Act Rules interpretations and withdrew questions 128.01 and 128.03 from the Securities Act Forms interpretations.

The Fixing America’s Surface Transportation Act

On December 4, 2015, President Obama signed into law the Fixing America’s Surface Transportation Act (the “FAST Act” or the “Act”). Among its many provisions, the Act amends the JOBS Act and certain SEC disclosure requirements. It also establishes a new statutory exemption for private resales of securities.

The [text](#) of the FAST Act is available on the U.S. Government Publishing Office’s Web site. Some of the Act’s key provisions are discussed below.

JOBS Act Changes for IPOs of Emerging Growth Companies

Among its changes related to IPOs and EGCs, the FAST Act:

- Reduces from 21 to 15 the number of calendar days before EGCs can commence a roadshow after publicly filing a registration statement with the SEC. This provision became effective immediately.
- Provides a grace period during which an EGC can continue to receive EGC treatment for certain purposes if it loses its EGC status during the SEC review process. The grace period ends on the earlier of (1) the consummation of the issuer’s IPO under the relevant registration statement or (2) one year after the issuer ceased to be an EGC. This provision became effective immediately.
- Permits EGCs to omit financial information from registration statements on Form S-1 or Form F-1 filed before an IPO (or confidentially submitted to the SEC for review) for historical periods required by Regulation S-X if the EGC reasonably believes that these historical periods will not be required to be included at the time of the contemplated offering. This provision is intended to apply in situations in which the SEC review process is likely to extend through a financial statement staleness date. Before the EGC distributes the preliminary prospectus to investors, the registration statement must be amended, if necessary, to include all financial information required by Regulation S-X as of the date of that amendment. The SEC had 30 days from the enactment date to promulgate rules effecting this change. However, issuers were permitted to omit such financial information starting on the 31st day after enactment.

On January 13, 2016, the SEC approved the issuance of [interim final rules](#) implementing certain provisions of the FAST Act. The interim final rules revise Forms S-1 and F-1 to allow for the omission of certain historical-period financial information before an offering insofar as an EGC’s registration statement includes the required financial information at the time of the offering. In addition, as noted in an SEC [press release](#), the interim final rules revise Form S-1 “to allow smaller reporting companies to use incorporation by reference for future filings the companies make under the federal securities laws after the registration statement becomes effective.” Further, the interim final rules include a request for comment on whether these changes should be expanded to other forms or registrants. The interim final rules will become effective upon publication in the *Federal Register*, with a 30-day comment period beginning thereafter.

Form 10-K and Regulation S-K Disclosure Changes

The FAST Act amends certain disclosure requirements related to Form 10-K and Regulation S-K. For example, the Act:

- Allows all issuers to submit a summary page on Form 10-K if each item on the summary page contains a cross-reference (which can be in the form of a hyperlink) to the material in the 10-K. The SEC has 180 days from enactment to implement this provision.
- Directs the SEC to simplify Regulation S-K and eliminate duplicative, overlapping, or otherwise unnecessary requirements for all issuers. The SEC has 180 days from enactment to implement this provision.
- Requires the SEC to study the requirements of Regulation S-K, report to Congress, and commence rulemaking on ways to (1) modernize and simplify Regulation S-K in a manner that reduces all costs and burdens on issuers, (2) emphasize a company-by-company approach that eliminates boilerplate language and static requirements, and (3) evaluate methods of information delivery and presentation that discourage repetition and the disclosure of immaterial information. The SEC has 360 days from enactment to submit the study findings and suggestions to Congress.

New Section 4(a)(7) Exemption for Private Resales

Private placement resales by persons other than the issuer, such as holders of restricted securities or affiliates of the issuer, were not eligible for Section 4(a)(2) of the Securities Act or Regulation D, which exempt private placements by issuers. New Section 4(a)(7) of the Securities Act provides a statutory exemption for private resales of restricted and control securities under certain conditions. Securities acquired in reliance on Section 4(a)(7) will be subject to transfer restrictions and covered securities will be exempt from certain “blue sky” laws. This provision became effective immediately.

Incorporation by Reference for Smaller Reporting Companies

The FAST Act allows smaller reporting companies (entities that, as of the last business day of their second fiscal quarter, have a public float of less than \$75 million) to automatically update information in a Form S-1 resale prospectus by incorporating by reference any documents filed with the SEC after the Form S-1 registration statement becomes effective. This method of updating information was previously available only to Form S-3 filers. The SEC has 45 days from enactment to implement this provision.

Compliance and Disclosure Interpretations of the FAST Act

In response to the issuance of the FAST Act, the SEC’s Division of Corporation Finance (the “Division”) has issued [C&DIs](#) of the FAST Act.

Interim Financial Statements

In one C&DI, the SEC staff addresses a key provision of the FAST Act that simplifies the disclosure requirements for EGCs. Under the FAST Act, an EGC may, for historical periods required by Regulation S-X, omit financial information from registration statements on Form S-1 or Form F-1 filed before an IPO (or confidentially submitted to the SEC for review) if the EGC reasonably believes that these historical periods will not be required to be included at the time of the contemplated offering. The SEC staff clarifies that interim financial information, including financial information for the comparative prior period, “relates” to both the interim period and a component of any longer period (interim or annual) in which it will be ultimately included. Thus, interim financial statements would be required in each filing of a registration statement, since any such periods will ultimately be included in either year-to-date interim periods or the annual periods presented in the registration statement as of the effective date.

The C&DI includes an example of a calendar-year-end EGC that submits or files a registration statement in December 2015 and reasonably expects to commence its offering in April 2016 when annual financial statements for 2015 and 2014 will be required. The C&DI states that in such a case, an EGC may not omit its nine-month 2014 and 2015 interim financial

statements “because those statements include financial information that relates to annual financial statements that will be required at the time of the offering in April 2016.”

Financial Statements of Other Entities

Another C&DI discusses financial statements of other entities (e.g., an acquired business under Regulation S-X, Rule 3-05) within the registration statement. It indicates that an EGC issuer may omit such financial statements from its filing or submission if the issuer reasonably believes that those financial statements will not be required at the time of the offering.

The SEC staff explains that “this situation could occur when an issuer updates its registration statement to include its 2015 annual financial statements prior to the offering and, after that update, the acquired business has been part of the issuer’s financial statements for a sufficient amount of time to obviate the need for separate financial statements.” The C&DI also includes a reference to paragraph 2030.4 of the Division’s [Financial Reporting Manual](#).

International Financial Reporting Standards

The SEC’s consideration of the potential incorporation of IFRSs into the U.S. financial reporting system has long been a topic of discussion at various conferences, including the annual AICPA Conference on Current SEC and PCAOB Developments (the “AICPA Conference”), and 2014 and 2015 were no exception. At the 2014 AICPA Conference, SEC Chief Accountant James Schnurr introduced a potential fourth alternative⁵ regarding the use of IFRSs in the United States that would allow U.S.-based filers to voluntarily provide supplemental IFRS-based information without reconciliation to U.S. GAAP. In his remarks before the 2015 AICPA Conference, Mr. Schnurr indicated that the SEC’s Office of the Chief Accountant is likely to recommend that the SEC consider and commence rulemaking that is consistent with this fourth alternative.

Further, in their respective remarks at the 2015 AICPA Conference, both SEC Chair Mary Jo White and Mr. Schnurr reemphasized the importance of continued FASB and IASB collaboration on standard-setting projects in an effort to improve the quality of financial reporting. These comments were echoed by IASB Chairman Hans Hoogervorst, who, in a call for renewed commitment to ongoing collaboration and convergence, asked participants to “stay engaged [with the IASB] and help us in continuing to build our Standards in the future.”

Other SEC Matters

Organizational Changes to SEC’s Division of Corporation Finance

During 2015, the SEC’s Division of Corporation Finance (the “Division”), which contains various assistant director (AD) offices with specialized industry expertise, made a number of organizational changes. The Division merged two of its AD offices responsible for small and large financial institutions into one AD office for financial services. In addition, the Division changed the responsibilities of the associate chief accountants in its Office of the Chief Accountant (CF-OCA); as a result, those individuals are now each responsible for specific topics rather than certain AD offices and industries so that they can develop more subject-matter expertise. The reorganization will also make the CF-OCA’s organizational structure more consistent with that of the OCA.

⁵ Before Mr. Schnurr’s 2014 speech, alternatives under consideration by the SEC regarding the use of IFRSs in the United States included (1) adopting IFRSs outright, (2) giving U.S. registrants the option of filing IFRS financial statements, and (3) using the so-called “condorsement” approach.

SEC's Request for Comment on Regulation S-X

On September 25, 2015, the SEC issued a [request for comment](#) (RFC) on registrants' views about the financial disclosure requirements under Regulation S-X for certain entities other than the registrant. The RFC asked for feedback about the financial statement and disclosure requirements for (1) businesses acquired or to be acquired under Rules 3-05, (2) subsidiaries not consolidated and 50 percent or less owned persons under Rule 3-09, (3) guarantors and issuers of guaranteed securities registered or being registered under Rule 3-10, and (4) affiliates whose securities collateralize an issue registered or being registered under Rule 3-16.

The SEC indicated that it was interested in hearing feedback from stakeholders about how they currently use the information disclosed under the existing rules and whether they find such information useful for making investment and voting decisions. In addition, the RFC asked whether the required information is presented at the right time and in the optimal manner to be useful. Further, the SEC had indicated that it also wants to know whether there is additional information that investors would find more useful for their decision making.

The public comment period closed on November 30, 2015, and the SEC staff is currently assessing the feedback received.

Thinking It Through

In recent speeches, SEC Chair Mary Jo White Chair indicated that the SEC next expects to address Regulation S-K and certain industry guides. Although Chair White did not touch on specifics in her remarks, aspects of Regulation S-K that might be examined include whether all of the required disclosures related to a registrant's business and operations remain relevant in the current business environment. We expect that in the near term, the SEC will issue an RFC on Regulation S-K similar to its RFC on Regulation S-X.

Financial Reporting Manual Updates

During 2015, the SEC's Division of Corporation Finance issued the following updates to its [Financial Reporting Manual](#):

- *January 12, 2015, updates* — The changes were made in light of the FASB's November 2014 issuance of ASU 2014-17 on pushdown accounting and the related rescission of SAB Topic 5.J. The SEC staff rescinded SAB Topic 5.J on November 18, 2014.
- *August 25, 2015, updates* — The changes updated paragraphs 1320.3 and 1320.4 to clarify that "[g]enerally, the Division of Corporation Finance will not issue comments asking a delinquent registrant to file separately all of its delinquent filings if the registrant files a comprehensive annual report on Form 10-K that includes all material information that would have been included in those filings." Previously, registrants would have sought such an accommodation in writing from the Division's Office of the Chief Accountant. The updates also reiterated that a registrant's filing of a comprehensive annual report on Form 10-K in those circumstances does not (1) absolve the registrant of any Exchange Act liability arising from its failure to file all required reports or shield it from any related enforcement actions; (2) make the registrant "current" for Regulation S, Rule 144, or Form S-8 filings; or (3) affect the registrant's inability to use Form S-3 until the timely-filer requirements are satisfied.

CAQ SEC Regulations Committee Meeting Highlights

The CAQ SEC Regulations Committee and SEC staff periodically meet to discuss various technical accounting and reporting matters, including current financial reporting matters and current practice issues. Highlights of the committee's [March 31, 2015](#), [June 18, 2015](#), and [October 21, 2015](#), joint meetings with the SEC staff are available on the CAQ's Web site.

SEC Publishes Examination Priorities for 2015

On January 13, 2015, the SEC's Office of Compliance Inspections and Examinations (OCIE) published its [examination priorities](#) for 2015. As explained in an SEC [press release](#), the priorities focus on "protecting retail investors, especially those saving for or in retirement; assessing market-wide risks; and using data analytics to identify signs of potential illegal activity."

The document is not necessarily comprehensive and “may be adjusted in light of market conditions, industry developments, and ongoing risk assessment activities.”

Cybersecurity

On February 3, 2015, the SEC’s OCIE issued a [cybersecurity risk alert](#). The risk alert summarizes the findings associated with an examination of over 100 investment advisers and broker-dealers conducted by the OCIE. The OCIE observed the entities’ practices related to “identifying risks related to cybersecurity; establishing cybersecurity governance, including policies, procedures, and oversight processes; protecting firm networks and information; identifying and addressing risks associated with remote access to client information and funds transfer requests; identifying and addressing risks associated with vendors and other third parties; and detecting unauthorized activity.” While the risk alert was issued to highlight considerations for registrants in the financial services industry, it is also relevant to the O&G sector.

Effects of Declines in Oil and Gas Prices

During 2015, the SEC staff continuously reminded registrants of the need to consider the effects of the decline in oil and gas prices on their results of operations, liquidity, and financial condition. Under Regulation S-K, Item 303, a registrant must disclose in MD&A any known trends or uncertainties that have had, or that are reasonably expected to have, a material impact on its results of operations (whether favorably or unfavorably). The SEC staff stressed the importance of a registrant’s MD&A disclosure of the decline in the prices of crude oil, gas, and other commodities (e.g., iron, copper) if the decline materially affects, or is expected to affect, the registrant’s operations.

See Deloitte’s December 15, 2015, [Heads Up](#) on the 2015 AICPA Conference and its March 11, 2015, [journal entry](#) for more information.

Communications to XBRL Filers

On December 30, 2014, the SEC announced its launch of a pilot program to help investors analyze and compare financial statement data submitted to the SEC by public companies. The data will be organized into structured sets of information from the companies’ XBRL exhibits in SEC filings and will be downloadable from the Commission’s Web site.

On March 9, 2015, the SEC staff announced an upgrade to its EDGAR system to support the 2015 U.S. GAAP financial reporting XBRL taxonomy. As noted on the [SEC’s Web site](#), the SEC staff “strongly encourages companies to use the most recent version of the US GAAP taxonomy release for their Interactive Data submissions to take advantage of the most up to date tags related to new accounting standards and other improvements.”

See Deloitte’s March 10, 2015, [journal entry](#) for more information.

Updates to EDGAR Filer Manual and Technical Specifications

On June 18, 2015, the SEC issued a [final rule](#) to implement Release 15.2 of its EDGAR system filer manual. The release updates Volume II of EDGAR as well as several XML technical specifications, including those related to EDGARLink Online and EDGAR ABS. Specific updates include:

- New and updated submission form types.
- Removal of OMB expiration dates from certain submission forms.
- Removal of support for US-GAAP-2013 and EXCH-2013 taxonomies.

The final rule became effective on June 29, 2015.

SEC Issues Concept Release on Audit Committee Disclosures

On July 1, 2015, the SEC issued a [concept release](#) requesting feedback on potential enhancements to the audit committee disclosure requirements. In particular, the Commission sought to learn more about the factors the audit committee considers when overseeing the independent auditor. Regarding the need for an ongoing assessment of these requirements, Chair White pointed out that “[t]he way audit committees exercise their oversight of independent auditors has evolved and it is important to evaluate whether investors have the information they need to make informed decisions.” Comments on the concept release were due by September 8, 2015.

See Deloitte’s July 15, 2015, [Heads Up](#) for additional information.

SEC and Other Organizations Publish Joint Staff Report on U.S. Treasury Market

On July 13, 2015, staffs of the SEC and four other agencies released a [joint staff report](#) that analyzes what the staffs’ related joint [press release](#) describes as “the significant volatility in the U.S. Treasury market on October 15, 2014.” As stated in the press release, the report notes that the volatility included “an unusually rapid round trip in prices and deterioration in liquidity during a narrow window” and concludes that it was caused by a number of factors, such as “changes in global risk sentiment and investor positions, a decline in order book depth, and changes in order flow and liquidity provision.”

SEC Staff Comments

The SEC staff’s comments to registrants in the O&G industry continue to focus on (1) distributable cash flow and maintenance capital expenditures for master limited partnerships (MLPs); (2) oil and gas reserves; (3) disclosures about drilling activities, wells and acreage data, and delivery commitments; income statement classification; and (5) declines in oil and gas prices.

Distributable Cash Flow and Maintenance Capital Expenditures for MLPs

Example of an SEC Comment

Please tell us and disclose whether you incurred any capital expenditures that had an element of both maintenance capital expenditures and expansion capital expenditures. If so, please revise your disclosure to quantify the portion allocated to expansion capital expenditures for each of the periods presented. In your response, please show us what your disclosure would have looked like had such disclosures been provided in your current Form 10-K.

The partnership agreements of MLPs typically define distributable cash flow and often call for a distinction between capital expenditures related to maintenance and those related to growth. In turn, MLPs frequently disclose distributable cash flow and capital expenditure amounts. Consequently, because distributable cash flow is not determined on the basis of SEC rules or U.S. GAAP, SEC staff comments to registrants in the O&G industry may focus on:

- Providing (1) greater clarity about how distributable cash flow is calculated and (2) disclosure of any changes in the calculation of distributable cash flows from prior periods.
- How maintenance capital expenditures are defined, and how they affect distributable cash flow.
- Describing the relationship between the calculated amount of distributable cash flow and actual distributions.
- Understanding the liquidity ramifications of cash distribution requirements, including the risk that the registrant will be unable to maintain the same level of distributions in the future.
- Compliance with the requirements of Regulation S-K, Item 10(e), related to non-GAAP financial measures.

Oil and Gas Reserves

PUD Reserves

Examples of an SEC Comment

- You state that “at June 30, 2014, none of our proved undeveloped reserves, which are all at [Location A], have remained undeveloped for five years from the date of initial recognition and disclosure as proved undeveloped reserves.” Please disclose the extent to which these proved undeveloped reserves are not expected to be converted from undeveloped to developed status within five years since your initial disclosure of these reserves. If any of your proved undeveloped reserves will take more than five years to develop since initial disclosure, you should disclose the specific circumstances to comply with Item 1203(d) of Regulation S-K.
- We note that your inventory of proved undeveloped drilling locations included four wells that had been recognized as proved reserves for five years or longer. Please quantify the reserves related to these wells, describe the specific circumstances that justified the continued recordation of these reserves, and outline your progress in drilling these four wells. Refer to Rule 4-10(a)(31) of Regulation S-X.

Under Regulation S-X, Rule 4-10(a)(22), a registrant should be reasonably certain when estimating proved reserves that the reserves can be recovered in future years under existing economic conditions. In accordance with Rule 4-10(a)(31)(ii), “[u]ndrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.”

At the 2014 AICPA Conference, the SEC staff referred registrants to Rule 4-10(a) and [Question 131.04 of the C&DIs of the oil and gas rules](#) for the definition of proved undeveloped (PUD) oil and gas reserves and staff views on the interaction of that definition with a registrant’s development plan. The staff noted that a mere intent to develop reserves does not constitute adoption of a development plan, which would require a final investment decision. Further, a registrant’s scheduled drilling activity should reconcile to its investment plans that have been approved by management.

The SEC staff may ask registrants to justify recorded PUD reserves that will remain undeveloped for more than five years because a registrant’s decision not to develop PUD reserves for such a long period may indicate uncertainty regarding development and ultimate recoverability. In accordance with Regulation S-K, Item 1203(d), a registrant may be asked to explain why the reserves have not been or will not be developed, why it believes that the reserves are still appropriate, and how it plans to develop the reserves within five years given the registrant’s historical conversion rate. The SEC staff may also ask registrants to support engineering assumptions, such as terminal decline rates, used in proved reserve estimates, as well as assumptions used in future cash flow analyses (e.g., estimated future well costs).

In addition, at the 2015 AICPA Conference, the SEC staff reminded registrants in the O&G industry to consider the recent declines in oil and gas prices and the related potential impact on exploration, development, and production levels. See [Declines in Oil and Gas Prices](#) below for more information.

Separate Disclosure of NGL Reserves

Example of an SEC Comment

We note your disclosure of “wet” natural gas reserves including NGLs in the presentation of your proved and probable reserves as of June 30, 2013. If your reserves as of June 30, 2013 represent a combination of two separate sales products, please revise your disclosure to provide separate disclosure by product type. In this regard, the staff considers natural gas liquids to be a separate product type under Item 1202(a)(4) of Regulation S-K. Therefore, NGL reserves, if material, should be presented as separate quantities for disclosure under Item 1202(a)(2) of Regulation S-K. Please revise your disclosure or tell us why a revision is not necessary.

Although NGLs are not separately identified as a product type in Regulation S-K, Item 1202(a), they are discussed in ASC 932-235-50-4. Accordingly, the SEC staff may ask registrants to disclose NGLs separately if they aggregate significant NGLs with other product types in their disclosures of proved reserves.

Significant Changes in Reserves and Standardized Measures

Examples of an SEC Comment

- Please revise your disclosure to include an explanation of significant changes in reserve quantities as discussed in FASB ASC 932-235-50-10.
- Despite the decrease in [PUDs] from [X thousand barrels of oil equivalent (MBoe)] at December 31, 2013 to [X] MBoe at December 31, 2014, we note that future development costs used to calculate the standardized measure of discounted future net cash flows increased from approximately \$[X] to approximately \$[X]. Please tell us whether you expect the PUDs recorded as of December 31, 2014 to require greater expenditure for development to proved developed status than PUDs converted in prior periods.

The SEC staff has commented on registrants' disclosures about (1) changes in proved reserves and standardized measures and (2) their compliance with ASC 932-235-50. Accordingly, the SEC staff may ask registrants to:

- Describe the technical factors (e.g., the activities, findings, and circumstances) that led to significant changes in proved reserves.
- Address negatively revised estimates attributable to performance separately from negatively revised estimates attributable to price reductions.
- Explain significant changes in extensions and discoveries.
- Disclose prices used in the calculation of standardized measures.
- Discuss how certain tax attributes were used to determine the future income tax expenses.

Further, the SEC staff may (1) ask registrants whether abandoned assets have been included in the standardized measure and, if so, to provide information about them and (2) refer registrants to a sample letter expressing views of the SEC's Division of Corporation Finance on the required disclosures.

Reserve Reports

Example of an SEC Comment

The discussion of methods employed in the estimation of reserves provided in the Appendix to the reserves report lists four methods customarily employed in the estimation of reserves. While this appears to be a comprehensive list of the methods available to the evaluator, Item 1202(a)(8)(iv) of Regulation S-K requires that the disclosure should address the methods and procedures used in connection with the preparation of the estimates specific to the report. Please obtain and file an amended report to revise the discussion, if necessary, to list only those methods and/or combinations of methods actually used to estimate the reserves contained in the report.

Under Regulation S-K, Item 1202(a)(8), a registrant must file a third-party report as an exhibit to its periodic report or registration statement when it "represents that a third party prepared, or conducted a reserves audit of, the registrant's reserves estimates, or any estimated valuation thereof, or conducted a process review." Accordingly, certain disclosures are required under Item 1202(a)(8). The SEC staff issues comments when these required disclosures are omitted. Often, the staff's comments are related to the requirement in Item 1202(a)(8)(iv) to disclose the "assumptions, data, methods, and procedures used, including the percentage of the registrant's total reserves reviewed in connection with the preparation of the report, and a statement that such assumptions, data, methods, and procedures are appropriate for the purpose served by the report."

Drilling Activities, Wells, Acreage, and Delivery Commitments

Examples of an SEC Comment

- [P]lease revise your disclosure to provide additional information regarding the minimum remaining terms of leases and concessions. As currently presented, your disclosure only provides information on acreage expirations for the three fiscal years following the periods covered by your Form 10-K. Refer to Item 1208(b) of Regulation S-K.
- Please expand the disclosure of your production to present the total annual quantities, by final product sold, for each of the periods presented to comply with the requirements in Item 1204(a) of Regulation S-K.

The SEC staff has continued to focus on registrants' disclosures about production information, drilling activities, wells and acreage data, and delivery commitments under Regulation S-K, Items 1204 through 1208. Additional disclosures that may be requested include (but are not limited to) the following:

- Production by geographic area and for each country and field that contains 15 percent or more of the registrant's total proved reserves.
- Drilling activities for each of the last three years by geographic area.
- Steps to be taken to meet significant delivery commitments.
- The number of wells that the registrant operates, including the total gross and net productive wells, expressed separately for oil and gas by geographic area.
- Information related to undeveloped acreage regarding minimum remaining terms of leases and concessions for material acreage concentrations, including significant undeveloped acreage that will be expiring over the next three years.

Income Statement Classification

Example of an SEC Comment

We note your disclosure . . . indicating that in certain instances you take title to the natural gas, NGLs or crude oil that you gather, store, or transport for your customers. We further note the disclosure in your revenue recognition footnote . . . that you recognize revenues for services and products. Please tell us how much revenue you have recognized, for each financial period presented, related to the sales of tangible product for which you have taken title and the amount of revenue related to services. Also tell us how you determined you were not required to separately disclose net sales of tangible products and revenues from services to comply with Rule 5-03(b)(1) of Regulation S-X and to separately disclose the related costs and expenses to comply with Rule 5-03(b)(2).

Under Regulation S-X, Rule 5-03, if product or service revenue is greater than 10 percent of total revenue, disclosure of such component is required as a separate line item on the face of the income statement, and costs and expenses related to the product or service revenue should be presented in the same manner. Revenue streams vary by sector within the O&G industry. For example, in the midstream sector, revenue streams could include transportation and storage of crude or refined petroleum products, processing of natural gas, and marketing fees generated from the sale of such products. In connection with these services, midstream companies may purchase, take title to, or otherwise have risk of ownership for the related products they are transporting, storing, or processing. If revenues from these product sales exceed 10 percent of total revenues, registrants are required to disclose such revenues and costs and expenses separately in the income statement. For more information, see the Financial Statement Classification, Including Other Comprehensive Income section of Deloitte's *SEC Comment Letters — Including Industry Insights: What "Edgar" Told Us*.

Declines in Oil and Gas Prices

Examples of an SEC Comment

You indicate that a continued low price environment could cause a “significant revision” in the carrying value of oil and gas properties in future periods. Section III.B.3. of SEC Release No. 33-8350 provides guidance regarding quantitative disclosure of reasonably likely effects of material trends and uncertainties. Please revise to provide more extensive discussion, including, where reasonably practicable, quantification of the impact of current commodity prices on the carrying value of your oil and gas properties. Your revised disclosure should also quantify the impact of potential scenarios deemed reasonably likely to occur on your estimated reserve volumes.

At the 2015 AICPA Conference, the SEC staff reminded registrants in the O&G industry to consider the recent declines in oil and gas prices and that such changes may:

- Represent a known trend or uncertainty that should be discussed in MD&A.
- Represent a risk that should be discussed in risk factor disclosures.
- Affect the determination of estimated proved reserves.

The SEC staff has noted that one of the most important elements necessary to gaining an understanding of a company’s performance, and the extent to which reported financial information is indicative of future results, is the discussion and analysis of known trends and uncertainties. Section III.B.3 of SEC Release No. 33-8350 calls for the quantification of material effects of known material trends and uncertainties and states that “material forward-looking information regarding known material trends and uncertainties is required to be disclosed as part of the required discussion of those matters and the analysis of their effects.” Given the nature of the O&G industry, significant changes to commodity prices could affect the overall operations of the company. In particular, a significant decline in commodity prices could have a material impact on the carrying value of an exploration and production company’s oil and gas properties and may be an early-warning sign of impairment. Accordingly, registrants in the O&G industry should quantify, to the extent possible, the impact of commodity prices on their (1) future development and capital programs and (2) oil and gas properties, including reserves. For more information, see Deloitte’s January 2015 *Oil & Gas Spotlight*. Registrants should also consider their risk factor disclosures, including quantitative disclosures about the potential impact of the recent changes in commodity prices on their reserves, and whether those disclosures adequately address the risks arising from the uncertainty associated with the price changes. See [PUD Reserves](#) above.



Section 7

Carve-Out Financial Statements

Background

In response to various market factors, O&G entities may seek to dispose of a portion of their operations or spin off portions of their business into a separate entity. One factor contributing to a recent increase in such divestitures is deregulation in certain jurisdictions, which has resulted in utilities with increasingly unregulated operations. In addition, recent energy efficiency programs and stagnant demand have led utilities to seek value in innovative ways, including the use of structures such as yieldcos. These and other market considerations have led companies to divest undervalued or strategically misaligned operations to unlock their value.

A carve-out occurs when a parent company segregates a portion of its operations and prepares a distinct set of financial information in anticipation of a sale, spin-off, or divestiture of a portion of its operations. The segregated operations are referred to as the “carve-out entity.” The carve-out entity may consist of all or part of an individual subsidiary, multiple subsidiaries, or even an individual segment or multiple segments. In some cases, one or more portions of a previously consolidated parent company’s subsidiaries may constitute the newly defined carve-out entity.

The term “carve-out financial statements” describes the separate financial statements that are derived from the financial statements of a parent company. The form and content of those financial statements may vary depending on the circumstances of the transaction. For example, if the carve-out financial statements are to be used solely by a small, strategic buyer, an unaudited balance sheet and income statement for the most recent fiscal year may be sufficient. A public buyer, however, may need a full set of SEC-compliant audited financial statements, including related disclosures, for the three most recent fiscal years. Yet another buyer might ask that the periods be audited but may be completely unconcerned with SEC reporting considerations. Accordingly, assessing the needs of potential financial statement users is critical to understanding the level of detail and number of periods to be presented in the carve-out financial statements.

Such an assessment can be challenging when the carve-out financial statements are being prepared before all relevant information is known (e.g., before a method of disposal has been determined, before the buyer has been identified).

Internal Control Considerations

It is important for O&G entities to consider internal control over financial reporting (ICFR) when preparing carve-out financial statements. Key questions for entities to ask about ICFR include:

- Has existing ICFR for the host entity been sufficiently precise for purposes of the carve-out financial statements?
- What new accounting and reporting risks exist with respect to the carve-out entity and the process for preparing the carve-out financial statements?

Because carve-out financial statements represent a subset (or subsets) of an existing entity, the parent entity’s ICFR typically governs the carve-out entity’s transactions and processes. However, previous ICFR may not have been sufficiently precise to address the risks of misstatement related to the carve-out financial statements.

Implementing and evaluating ICFR related to carve-out financial statements is critical given the amount of judgment an entity must exercise in preparing these statements. Entities considering the preparation of carve-out financial statements should evaluate ICFR as part of their pre-transaction planning activities and determine whether they need to implement additional control activities, training programs, or financial reporting processes to sufficiently address the risk of material misstatement. Given the nature of carve-out statements (e.g., reliance on several judgments and allocations, incorporation of transactions and events that may have occurred multiple years in the past), many of the control activities an entity implements are likely to be management review controls with a focus on the level of precision of the review and the experience of the individuals responsible for performing the control activity.

The sections below discuss some of the considerations an entity should take into account when preparing carve-out financial statements.

Judgments and Allocations

Numerous challenges may arise when an entity carves out activity and balances from the parent's historical financial statements. For the statement of operations, management can often specifically identify revenues, including intercompany revenues, related to the carve-out entity. However, expenses can be more difficult. Carve-out financial statements are intended to reflect all costs of doing business. Although costs incurred by the parent on behalf of the carve-out entity must be reflected in the carve-out financial statements, such costs are often related to many different operations and cannot be specifically identified as part of the carve-out entity. In such cases, an entity must use a reasonable allocation method. Allocation methods in the industry are often based on items such as generation capacity, energy generated, headcount, and payroll.

For the balance sheet, an entity generally begins by identifying the assets and liabilities related to the carve-out entity. However, this process can be challenging when some assets or liabilities are commingled or combined with assets or liabilities related to other parts of the business. For example, cash, accounts receivable, and accounts payable are often commingled because they are managed centrally. Goodwill, debt, and pensions can also present a challenge because these assets or liabilities are often not recorded at the level of the carve-out entity. For each of these asset and liability classes, an entity will need to determine whether amounts should be attributed to the carve-out entity.

In addition to implementing control and planning activities to address the risk of material misstatement (as discussed in [Internal Control Considerations](#) above), entities should document management's rationale for significant conclusions reached, since judgments and allocations often have a material impact on the carve-out financial statements.

Tax Considerations

When performing a carve-out, an entity should pay particular attention to the legal structure of the transaction to avoid unintended tax consequences. Specifically, the manner in which the carve-out transaction occurs can affect whether the transaction represents a taxable event. In addition, an entity may need to determine the impact of changes in state tax rates and the changes to apportionment factors if assets are transferred between state jurisdictions. To avoid these unintended consequences, tax departments should be consulted in the planning stages of the carve-out transaction and involved in drafting the legal documents governing the transaction.

Reporting Considerations

The sections below discuss aspects of carve-out financial statements that typically involve complex financial reporting considerations. In evaluating these considerations, a reporting entity must use judgment and assess its specific facts and circumstances.

Thinking It Through

Paragraph 2065.11 of the FRM details the financial statement requirements for an “acquisition of an interest in a producing oil or natural gas property.” The FRM notes that “[i]f the property acquired represents less than substantially all of the selling entity’s key operating assets, the registrant should provide the carve-out financial statements.” Paragraph 2065.11 also highlights that the SEC staff will accept abbreviated financial statements (e.g., statements of revenues and direct expenses) in lieu of the full financial statements required under Regulation S-X, Rule 3-05, in certain specified circumstances. Registrants are no longer required to preclear their submission of abbreviated financial statements with the Office of the Chief Accountant in the Division of Corporation Finance.

Discontinued Operations

In a carve-out transaction, a parent company generally disposes (or plans to dispose) of a portion of its operations. As a result, the ongoing entity should consider whether the operations that are, or will be, disposed of meet the criteria for classification as held for sale or presentation as a discontinued operation in the parent company’s financial statements. If the criteria for reporting discontinued operations are met, it is unlikely that amounts presented as discontinued operations for the carve-out entity in the parent company’s financial statements would equal the amounts for the operations reflected in the carve-out entity’s separate financial statements (e.g., because of differences in how expenses may have been allocated).

In April, 2014, the FASB issued [ASU 2014-08](#) (codified in ASC 205-20), which changed the criteria for reporting discontinued operations and has reduced the frequency with which disposals qualify for presentation as a discontinued operation.

Business Segment Disclosure

Disposal transactions may have an impact on the parent entity’s segment reporting. A disposal of a significant portion of the parent entity’s operations could cause a change in management’s view of the business or in the parent entity’s segments.

Further, in preparation for a disposal, management may seek to realign the business and may legally transfer operations or assets from one segment to another. If segments are restructured, management should consider the guidance in ASC 280-10-50-34, under which an entity is required to retrospectively apply the segment change to earlier accounting periods. In addition, if the carve-out statements will be used in a public filing, the carve-out statements will also need to disclose the segments identified in the formation of the new carve-out entity.

Transactions Between Entities Under Common Control

A transaction within a consolidated group may result in retrospective reporting requirements in accordance with ASC 805-50 if the acquiring entity prepares stand-alone financial statements. For example, in preparation for a disposal, management may transfer certain assets or operations to a new legal entity within the consolidated group. Such transactions are accounted for as transactions between entities under common control and have no accounting impact (other than a possible impact on segment disclosures) at the consolidated level. However, if subsidiaries of the parent entity prepare stand-alone financial statements, there may be an impact on the stand-alone financial statements when assets or operations are transferred to or from the subsidiary. A transaction between entities under common control is accounted for at the parent entity’s historical cost.

The transferring subsidiary generally would report the transfer as a disposal in its stand-alone financial statements and assess whether the disposal should be presented as a discontinued operation. The reporting by the receiving subsidiary depends on whether the transfer represents a “change in reporting entity” under ASC 250. A change in reporting entity results in presentation of the transfer as if it had occurred at the beginning of the earliest reporting period presented in the subsidiary’s stand-alone financial statements (such presentation is often called an “as-if pooling”). Alternatively, the receiving

entity prospectively reports transfers that do not represent a change in reporting entity. An entity must use judgment in determining whether a transfer results in a change in reporting entity.

SEC Reporting

SEC registrants often have additional matters to consider when reporting disposal transactions, including how to report pro forma financial information. For example, Item 2.01 of the SEC's Form 8-K contains disclosure requirements related to acquisitions or dispositions of a significant amount of assets. (Note that the instructions to Item 2.01 specify what constitutes a "significant amount of assets.") The disclosures that an entity is required to provide in accordance with this SEC guidance will depend on the facts and circumstances of the transaction but may include audited financial statements or pro forma financial information that contains the balances and activity of the acquired or disposed-of entity. In these situations, the required financial information is typically based on carve-out financial statements of the transferred entity; certain adjustments may be made on the basis of the nature of the reporting requirements.

Other Resources

For more information on carve-out financial statements, see Deloitte's [*A Roadmap to Accounting and Financial Reporting for Carve-Out Transactions*](#).



Section 8

Income Tax Update

This section summarizes (1) recently enacted federal legislation affecting the financial reporting of income taxes and (2) new and proposed FASB guidance on accounting for income taxes.

Federal Legislation

On December 18, 2015, President Obama signed into law the Protecting Americans From Tax Hikes Act of 2015 (the “PATH Act” or the “Act”), which, among other things:

- Extends and modifies bonus depreciation through 2019.
- Extends and modifies the election to claim refundable alternative minimum tax (AMT) credits in lieu of bonus depreciation under IRC Section 168(k)(4).
- Makes permanent the 15-year depreciation for certain qualified leasehold improvement property (QLIP), qualified retail improvement property (QRIP), and qualified restaurant property (QRP).
- Makes permanent IRC Section 179 expensing.

Bonus Depreciation

The PATH Act extends 50 percent bonus depreciation for eligible qualifying assets placed in service after December 31, 2014, and before January 1, 2018 (January 1, 2019, for certain transportation and longer production period property). In addition, the Act allows bonus depreciation of 40 percent for eligible qualifying assets placed in service in 2018 and 30 percent for eligible qualifying assets placed in service in 2019.

For certain transportation and longer production period property, the 40 percent bonus depreciation applies to expenditures incurred during 2018 if such property is placed in service during 2019, and the 30 percent bonus depreciation applies to expenditures incurred in 2019 if such property is placed in service in 2020. The law also provides a phase-down for the additional amounts of depreciation computed under IRC Section 280F; the amounts are \$8,000 for automobiles placed in service in 2015–2017, \$6,400 for autos placed in service in 2018, and \$4,800 for autos placed in service in 2019.

The PATH Act includes modifications to the property eligible for bonus depreciation beginning in 2016. For example, it replaces the term “qualified leasehold improvement property” with “qualified improvement property.” The new term is defined as “any improvement to an interior portion of a building which is nonresidential real property if such improvement is placed in service after the date such building was first placed in service,” although the term excludes expenditures related to (1) enlargement of the building, (2) any elevator or escalator, or (3) the internal structural framework of the building. Thus, improvements eligible for bonus depreciation are no longer limited to leasehold improvements placed in service more than three years after the building was placed in service.

Election to Claim Refundable AMT Credits in Lieu of Bonus Depreciation

The PATH Act extends and modifies IRC Section 168(k)(4), which permits corporations to claim a refundable credit (computed, in part, by reference to their carryforward AMT credits) in lieu of claiming bonus depreciation otherwise allowed for qualified property placed in service in 2015–2020. When a corporation makes a Section 168(k)(4) election, not only must the corporation and any other corporate members of its controlled group forgo bonus depreciation, but they also are generally required to use the straight-line method to depreciate the qualified property.

For qualified property placed in service during 2015, a corporation is allowed to make a Section 168(k)(4) election for so-called “round 5 extension property,” with respect to which the refundable credit will be computed in accordance with the same formula that previously applied to other temporary extensions of the Section 168(k)(4) regime, including the limitation that the credit cannot exceed the lower of 6 percent of the cumulative AMT credits attributable to taxable years beginning before 2006 or \$30 million (i.e., the credit will be computed under the same formula that applied to “round 4 extension property”).

For qualified property placed in service during 2016 or later years, the PATH Act modifies — and generally enhances — the Section 168(k)(4) regime so that the election to forgo bonus depreciation may be made annually for each taxable year and the maximum Section 168(k)(4) credit allowed for each taxable year generally will be limited to 50 percent of the cumulative unused AMT credits attributable to taxable years ending before 2016 (without a specific dollar cap). As prescribed under pre-amended Section 168(k)(4), an electing corporation would perform the credit computation in two steps:

- Multiply by 20 percent the total amount of first-year bonus depreciation the corporation is forgoing for qualified property placed in service during the taxable year.
- Determine whether the allowable credit must be further reduced by taking into consideration the corporation's cumulative AMT credits.

The PATH Act also modifies the rules governing flow-through depreciation from partnerships to certain corporate partners that make a Section 168(k)(4) election. In addition, the Act provides special transition rules to determine the maximum Section 168(k)(4) credit allowed for a fiscal year that begins during 2015 and ends during 2016.

QLIP, QRIP, and QRP

Effective for assets placed in service after December 31, 2014, the PATH Act makes permanent the 15-year straight-line depreciation for QLIP, QRIP, and QRP. Because of the Act's amendments making bonus depreciation applicable to qualified improvements, the definition of qualified leasehold improvements previously in IRC Section 168(k)(3) was moved to IRC Section 168(e)(6). Thus, there is no change in the definitions of property to which the 15-year straight-line depreciation applies. In addition, the PATH Act removes the bonus depreciation exclusion for QRIP.

Section 179 Expensing

The PATH Act makes permanent the election under IRC Section 179 to expense up to \$500,000 per year of qualifying costs placed in service during a taxable year. The \$500,000 is reduced by the amount by which the cost of qualifying property placed in service during the taxable year exceeds \$2 million. The \$500,000 and \$2 million will be indexed for inflation. Taxpayers may revoke their Section 179 election without prior consent of the IRS commissioner.

Under the new law, Section 179 qualifying costs permanently include computer software to which IRC Section 167 applies. In addition, the PATH Act (1) makes permanent the treatment of qualified real property (i.e., QLIP, QRIP, or QRP) as eligible Section 179 property and (2) extends the limitations on carryovers and the maximum amount of \$250,000 available with respect to qualified real property for such taxable year but (3) removes the \$250,000 limitation for taxable years beginning after 2015. For 2016 and subsequent years, air conditioning and heating units are no longer excluded from the definition of IRC Section 1245 property eligible for Section 179 expensing.

New and Proposed FASB Guidance

Simplifying the Accounting for Income Taxes

On January 22, 2015, as noted in [Section 2](#) above, the FASB issued an exposure draft (ED) of two proposed ASUs in an effort to simplify the accounting for income taxes. Under the proposed guidance, (1) entities would no longer defer the income tax consequences of intra-entity asset transfers until the assets are ultimately sold to an outside party and (2) all deferred taxes would be classified as noncurrent assets or noncurrent liabilities. In November 2015, the Board issued a final ASU on the balance sheet classification of deferred taxes.

Intra-Entity Asset Transfers

Under existing guidance, ASC 740-10-25-3 prohibits an entity from recognizing current and deferred income tax consequences of an intra-entity asset transfer until the entity sells the asset(s) to an outside party. The proposed ASU on intra-entity asset transfers would eliminate this prohibition and would require recognition of the income tax consequences upon transfer.

For more information about the proposed ASU, see Deloitte's January 30, 2015, [Heads Up](#).

Balance Sheet Classification of Deferred Taxes

On November 20, 2015, the FASB issued [ASU 2015-17](#) to simplify the presentation of deferred taxes in a classified balance sheet. Under current guidance (ASC 740-10-45-4), entities "shall separate deferred tax liabilities and assets into a current amount and a noncurrent amount. Deferred tax liabilities and assets shall be classified as current or noncurrent based on the classification of the related asset or liability for financial reporting." Under the ASU, entities will be required to present deferred tax assets (DTAs) and deferred tax liabilities (DTLs) as noncurrent in a classified balance sheet.

Thinking It Through

Netting of DTAs and DTLs by tax jurisdiction will still be required under the new guidance. However, noncurrent balance sheet presentation of all deferred taxes eliminates the requirement to allocate a valuation allowance on a pro rata basis between gross current and noncurrent DTAs.

The ASU contains the following guidance on effective date and transition:

- For public business entities (PBEs), the ASU will be effective for annual periods beginning after December 15, 2016, and interim periods within those years.
- For non-PBEs, the ASU will be effective for annual reporting periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018.
- All entities are permitted to early adopt the ASU. Therefore, both PBEs and non-PBEs can adopt the ASU for any interim or annual financial statements that have not been issued.
- All entities are permitted to apply the ASU's amendments either prospectively or retrospectively.

In the period the ASU is adopted, an entity will need to disclose "the nature of and reason for the change in accounting principle." If the new guidance is applied prospectively, the entity should disclose that prior balance sheets were not retrospectively adjusted. However, if the new presentation is applied retrospectively, the entity will need to disclose the quantitative effects of the change on the prior balance sheets presented.

For more information about the ASU, including an example comparing the classification of DTAs and DTLs under current U.S. GAAP with their classification under the new guidance, see Deloitte's November 30, 2015, [Heads Up](#).

Accounting for Income Taxes on Share-Based Payments

In June 2015, the FASB issued a [proposed ASU](#) on share-based payments as part of its simplification initiative. The proposal addressed several aspects of the accounting for employee share-based payment transactions for both public and nonpublic entities, including the accounting for income taxes on share-based payments.

As noted in [Section 2](#) above, the FASB completed its redeliberations on the proposal at its November 23, 2015, meeting. During the meeting, the Board affirmed its proposed changes to the accounting for income taxes on the settlement of awards upon vesting, including (1) recognition of excess tax benefits and deficiencies as income tax expense or benefit in the income statement, (2) removal of the requirement to delay recognition of an excess tax benefit until the tax benefit is

realized, and (3) presentation of excess tax benefits in the statement of cash flows. The FASB expects to issue its final ASU in the first quarter of 2016.

Settlement of an Award

Under current guidance (ASC 718-740), entities generally record the excess of a realized tax benefit for an award over the DTA for that award as additional paid-in capital (APIC). To the extent that the write-off of a DTA for an award is greater than the tax benefit, this deficiency is generally offset first against APIC, subject to certain limitations. The remainder, if any, is recognized in the income statement.

The FASB indicated that under the forthcoming final ASU, all excess tax benefits and all tax deficiencies will be recognized as income tax expense or benefit in the income statement. The FASB also clarified that the tax effects of exercised or vested awards are discrete items in the reporting period in which they occur (i.e., entities would not consider them in determining the annual estimated effective tax rate.)

Previously Unrecognized Excess Tax Benefits

Under current guidance (ASC 718-740-25-10), a “share option exercise may result in a tax deduction before the actual **realization of the related tax benefit** because the entity, for example, has a net operating loss carryforward. In that situation, a tax benefit and a credit to [APIC] for the excess deduction **would not be recognized until that deduction reduces taxes payable**” (emphasis added).

The final ASU will remove this requirement. That is, an entity would recognize excess tax benefits regardless of whether the benefit reduces taxes payable in the current period.



Cash Flow Statement

Under current guidance, realized excess tax benefits are reported as cash inflows from financing activities and cash outflows from operating activities. Under the final ASU, excess tax benefits would not be separated from other income tax cash flows; rather, they would be classified along with other cash flows as an operating activity.

Transition Guidance

In its latest deliberations, the FASB decided to provide the following transition guidance:

- *Settlement of an award* — A prospective transition method applies.
- *Previously unrecognized excess tax benefits* — A modified retrospective transition method applies, including a cumulative-effect adjustment recognized in equity.
- *Cash flow statement* — Entities may use either a prospective transition method or a retrospective transition method.

Effective Date

The Board decided that for PBEs, the final ASU will be effective for annual periods beginning after December 15, 2016, and interim periods within those years. For non-PBEs, the final ASU will be effective for annual reporting periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018.

In addition, the Board decided to allow all entities to early adopt the final ASU. Therefore, the final ASU can be adopted by all entities for any interim or annual financial statements that have not been issued.

Other Resources

For more information, see Deloitte's [*Highlights From the FASB's November 23 Meeting*](#).



Appendixes

Appendix A — Abbreviations

Abbreviation	Description
ABS	asset-backed security
AD	assistant director
AFS	available for sale
AICPA	American Institute of Certified Public Accountants
AMT	alternative minimum tax
APIC	additional paid-in capital
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
B&E	blend and extend
Btu	British thermal unit
C&DI	SEC Compliance and Disclosure Interpretation
CAQ	Center for Audit Quality
CECL	current expected credit loss
CF-OCA	SEC's Division of Corporation Finance, Office of the Chief Accountant
CFTC	U.S. Commodity Futures Trading Commission
CMR	conflict minerals report
CWIP	construction work in progress
DCF	discounted cash flow
DRC	Democratic Republic of the Congo
DTA	deferred tax asset
DTL	deferred tax liability
E&P	exploration and production
ED	exposure draft
EDGAR	SEC's Electronic Data Gathering, Analysis, and Retrieval system
EGC	emerging growth company
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FIFO	first-in, first out
FRC	SEC Codification of Financial Reporting Policies
FRM	SEC Financial Reporting Manual
FVTNI	fair value through net income
GAAP	generally accepted accounting principles

Abbreviation	Description
HTM	held to maturity
IAS	International Accounting Standard
IASB	International Accounting Standards Board
ICFR	internal control over financial reporting
IFRS	International Financial Reporting Standard
IPO	initial public offering
IPSA	independent private-sector audit
IRC	Internal Revenue Code
IRS	Internal Revenue Service
LGD	loss given default
LIFO	last-in, first-out
LLC	limited liability company
LNG	liquefied natural gas
LP	limited partner
M&A	mergers and acquisitions
Mcf	thousand cubic feet
MD&A	Management's Discussion and Analysis
MLP	master limited partnership
MMBtu	million Btu
NGL	natural gas liquid
NRV	net realizable value
NYMEX	New York Mercantile Exchange
O&G	oil and gas
OCI	other comprehensive income
OCIE	SEC's Office of Compliance Inspections and Examinations
OMB	Office of Management and Budget
PBE	public business entity
PCAOB	Public Company Accounting Oversight Board
PCC	FASB's Private Company Council
PCI	purchased credit-impaired
PD	probability of default
PEMEX	Petróleos Mexicanos
PEO	principal executive officer
PUD	proved undeveloped

Abbreviation	Description
QLIP	qualified leasehold improvement property
QPE	qualified progress expenditure
QRIP	qualified retail improvement property
QRM	qualified residential mortgage
QRP	qualified restaurant property
RFC	request for comment
RIM	retail inventory method
ROU	right of use
RRWG	revenue recognition working group
SAB	SEC Staff Accounting Bulletin
SAC	subjective acceleration clause
SEC	Securities and Exchange Commission

Abbreviation	Description
SIFMA	Securities Industry and Financial Markets Association
SPEE	Society of Petroleum Evaluation Engineers
tbd	thousand barrels per day
TRG	transition resource group
TSR	total shareholder return
VIE	variable interest entity
VPP	volumetric production payment
WACC	weighted average cost of capital
WTI	West Texas Intermediate
XBRL	eXtensible Business Reporting Language

The following is a list of short references for the Acts mentioned in this publication:

Abbreviation	Act
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Exchange Act	Securities Exchange Act of 1934
FAST Act	Fixing America's Surface Transportation Act
JOBS Act	Jumpstart Our Business Startups Act
PATH Act	Protecting Americans From Tax Hikes Act of 2015
Securities Act	Securities Act of 1933

Appendix B — Titles of Standards and Other Literature

The titles of the standards and other literature referred to in this publication are available from the sources below.

FASB ASC References

For titles of *FASB Accounting Standards Codification* references, see Deloitte's "[Titles of Topics and Subtopics in the FASB Accounting Standards Codification](#)."

FASB Accounting Standards Updates and Other FASB Literature

See the FASB's Web site for the titles of:

- [Accounting Standards Updates](#).
- [Proposed Accounting Standards Updates](#) (exposure drafts and public comment documents).
- [Pre-Codification literature](#) (Statements, Staff Positions, EITF Issues, and Topics).
- [Concepts Statements](#).

SEC C&DI Topics

FAST Act

Oil & Gas Rules

Regulation A

SEC Codification of Financial Reporting Policies

Section 406.01.c, "Full Cost Method"

SEC Concept Release

33-9862, *Possible Revisions to Audit Committee Disclosures*

SEC Final Rules

34-73407, *Credit Risk Retention*

34-67716, *Conflict Minerals*

33-9877, *Pay Ratio Disclosure*

33-9849, *Adoption of Updated EDGAR Filer Manual*

33-9741, *Amendments for Small and Additional Issues Exemptions Under the Securities Act (Regulation A)*

SEC Interim Final Rule

33-10003, *Simplification of Disclosure Requirements for Emerging Growth Companies and Forward Incorporation by Reference on Form S-1 for Smaller Reporting Companies*

SEC and CFTC Interpretive Release

34-74936, *Forward Contracts With Embedded Volumetric Optionality*

SEC Proposed Rules

34-76620, *Disclosure of Payments by Resource Extraction Issuers*

34-74835, *Pay Versus Performance*

34-74834, *Application of Certain Title VII Requirements to Security-Based Swap Transactions Connected With a Non-U.S. Person's Dealing Activity That Are Arranged, Negotiated, or Executed by Personnel Located in a U.S. Branch or Office or in a U.S. Branch or Office of an Agent*

33-9861, *Listing Standards for Recovery of Erroneously Awarded Compensation*

33-9723, *Disclosure of Hedging by Employees, Officers and Directors*

33-9693, *Changes to Exchange Act Registration Requirements to Implement Title V and Title VI of the JOBS Act*

SEC Request for Comment

33-9929, *Request for Comment on the Effectiveness of Financial Disclosures*

SEC Division of Corporation Finance Financial Reporting Manual

Topic 1, "Registrant's Financial Statements," paragraphs 1320.3 and 1320.4

Topic 2, "Other Financial Statements Required," paragraphs 2030.4 and 2065.11

SEC Forms

Form 8-K, "Current Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934": Item 2.01, "Completion of Acquisition or Disposition of Assets"

Form 10-K, "General Form of Annual Report"

Form F-1, "Registration Statement for Securities of Certain Foreign Private Issuers"

Form S-1, "Registration Statement Under the Securities Act of 1933"

Form S-3, "Registration Statement Under the Securities Act of 1933"

Form S-8, "Registration Statement Under the Securities Act of 1933"

Form SD, "Specialized Disclosure Report"

SEC Guidance

Amendments to Regulation A: A Small Entity Compliance Guide

SEC Office of Compliance Inspections and Examinations

Examination Priorities for 2015

Risk Alert, Vol. IV, Issue 4, *Cybersecurity Examination Sweep Summary*

SEC Regulations

Regulation A, "Conditional Small Issues Exemption"

Regulation D, “Rules Governing the Limited Offer and Sale of Securities Without Registration Under the Securities Act of 1933”

Regulation D, Rule 501(a), “Definitions and Terms Used in Regulation D: Accredited Investor”

Regulation S-K:

- Item 10(e), “General: Use of Non-GAAP Financial Measures in Commission Filings”
- Item 301, “Selected Financial Data”
- Item 303, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”
- Item 402, “Executive Compensation”
- Item 1202, “Disclosure of Reserves”
- Item 1203, “Proved Undeveloped Reserves”
- Item 1204, “Oil and Gas Production, Production Prices and Production Costs”
- Item 1205, “Drilling and Other Exploratory and Development Activities”
- Item 1206, “Present Activities”
- Item 1207, “Delivery Commitments”
- Item 1208, “Oil and Gas Properties, Wells, Operations, and Acreage”

Regulation S-X:

- Rule 3-05, “Financial Statements of Businesses Acquired or to Be Acquired”
- Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
- Rule 3-10, “Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered”
- Rule 3-16, “Financial Statements of Affiliates Whose Securities Collateralize an Issue Registered or Being Registered”
- Rule 4-08(e), “General Notes to Financial Statements: Restrictions Which Limit the Payment of Dividends by the Registrant”
- Rule 4-10, “Financial Accounting and Reporting for Oil and Gas Producing Activities Pursuant to the Federal Securities Laws and the Energy Policy And Conservation Act of 1975”
- Rule 5-03, “Commercial and Industrial Companies: Income Statements”
- Rule 5-03(b)(1), “Commercial and Industrial Companies: Income Statements: Net Sales and Gross Revenues”
- Rule 5-03(b)(2), “Commercial and Industrial Companies: Income Statements: Costs and Expenses Applicable to Sales and Revenues”

SEC Staff Accounting Bulletins

Topic 5.J, “New Basis of Accounting Required in Certain Circumstances” (Removed by SAB 115)

Topic 11.M, “Disclosure of the Impact That Recently Issued Accounting Standards Will Have on the Financial Statements of the Registrant When Adopted in a Future Period”

Topic 12.D, “Application of Full Cost Method of Accounting”

Topic 13, “Revenue Recognition”

SEC Securities Exchange Act of 1934 Rules

Rule 12g-1, "Exemption From Section 12(g)"

Rule 12g-2, "Securities Deemed to Be Registered Pursuant to Section 12(g)(1) Upon Termination of Exemption Pursuant to Section 12(g)(2) (A) or (B)"

Rule 12g-3, "Registration of Securities of Successor Issuers Under Section 12(b) or 12(g)"

Rule 12g-4, "Certifications of Termination of Registration Under Section 12(g)"

Rule 12h-3, "Suspension of Duty to File Reports Under Section 15(d)"

SEC, U.S. Department of the Treasury, Federal Reserve, the Federal Reserve Bank of New York, and the U.S. Commodity Futures Trading Commission

Joint Staff Report, "The U.S. Treasury Market on October 15, 2014"

Other

17 CFR Chapter I, Commodity Futures Trading Commission, Part 144, "Procedures Regarding the Disclosure of Information and the Testimony of Present or Former Officers and Employees in Response to Subpoenas or Other Demands of a Court"

International Standards

See Deloitte Touche Tohmatsu Limited's [IAS Plus Web site](#) for the titles of:

- International Financial Reporting Standards.
- International Accounting Standards.
- [Exposure documents](#).

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Appendix D — Other Resources and Upcoming Events

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Upcoming Dbriefs

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February 3, 2016

For more information, visit: <http://www2.deloitte.com/us/en/pages/dbriefs-webcasts/events/february/2016/dbriefs-mergers-and-acquisitions-update-could-low-oil-and-gas-prices-translate-into-high-deal-volume.html>.

LNG in Flux: Key Drivers in a Changing Landscape

March 10, 2016

For more information, visit: <http://www2.deloitte.com/us/en/pages/dbriefs-webcasts/events/march/2016/dbriefs-lng-in-flux-key-drivers-in-changing-landscape.html>.

Events

M&A Executive Forum

Dallas, Texas | March 8, 2016

For more information, please contact: bridobrien@deloitte.com.

Oklahoma City Memorial Marathon Sponsorship

Oklahoma City, Oklahoma | April 24, 2016

For more information, please contact: krconklin@deloitte.com.

MergerMarket Energy Conference

May 2016

For more information, please contact: lmconn@deloitte.com.

Deloitte Energy Conference

Washington, D.C. | June 21–22, 2016

For more information, visit: www.deloitte.com/us/energyevents.

Deloitte Oil & Gas Conference

Houston, Texas | September 21–22, 2016

For more information, visit: www.deloitte.com/us/energyevents.

Deloitte Energy Transacting: A View on Accounting and Valuation

Chicago, Illinois | December 2016

For more information, visit: www.deloitte.com/us/energyevents.

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