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Financial Accounting Standards Board
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File Reference: 1820-100 - Revenue Recognition, Revenue from Contracts with Customers

The Edison Electric Institute (EEI) respectfully submits our comments on the Financial Accounting Standards Board (FASB or the Board) Proposed Accounting Standards Update—*Revenue Recognition (Topic 605) Revenue from Contracts with Customers* (the ED). EEI is the association of United States shareholder-owned electric companies. Our members provide service to 95 percent of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70 percent of the United States electric power industry.

EEI appreciates the FASB and International Accounting Standards Board (IASB) (collectively the Boards) seeking to develop a converged standard on revenue recognition. The proposed changes to revenue recognition will have unique effects on many different industries, and there are many provisions included in the ED that will significantly affect energy companies and regulated utilities. We have limited our responses to questions for which we have specific concerns and items for which we request clarification, make recommendations, or wish to convey our support. In addition, we have addressed certain areas of diversity in practice of which we are aware that, while not covered by specific questions, directly relate to matters impacted by the ED.

Summary

Highlights of our comments are summarized as follows:

- We believe the guidance currently included in ASC 980, *Regulated Industries*, related to the accounting for alternative revenue programs should not be eliminated as proposed in the ED.
- We seek clarification on the proposed accounting for contract modifications.
- We seek clarification on the proposed accounting for multiple deliverable arrangements.
- We disagree with the proposed credit risk model as it will reduce transparency and is inconsistent with other standards, including the recently proposed ASU for financial instruments.
- We do not agree with certain aspects of the proposals related to onerous performance obligations and request clarification on others.
- We believe the proposed disclosures of the remaining and expected timing of satisfaction of performance obligations could be misinterpreted by users and could potentially create discrepancies with other financial information provided to investors.
- We believe the proposed disclosures of the remaining and expected timing of satisfaction of performance obligations could be misinterpreted by users and could potentially create discrepancies with other financial information provided to investors.
- We do not believe the proposed retrospective application of this standard is operational and suggest prospective application.

We provide our comments on selected questions in the ED that are relevant to our member companies below.

Alternative Revenue Arrangements

In the ED, the Board has proposed that the ASU supersede or amend most industry-specific revenue recognition subtopics in the Accounting Standards Codification (ASC), including superseding ASC 980-605-25, *Regulated Industries – Revenue Recognition – Alternative Revenue Program* (guidance originally issued as Emerging Issues Task Force (EITF) Issue No. 92-7, *Accounting for Rate-Regulated Utilities for the Effects of Certain Alternative Revenue Programs).* Currently, ASC 980-605-25 supports recognition of regulatory assets related to decoupling programs, incentive revenue plans and other alternative revenue programs, which enable the utility to adjust future rates in response to past activities or completed events. The guidance issued in EITF 92-7 confirmed the industry practice of recording regulatory assets related to under-collected revenue requirements associated with these alternative revenue programs, if certain criteria are met. This EITF consensus on this issue was necessitated by the fact that, when originally written, Statement of Financial Accounting Standards number 71, *Accounting for Certain Types of Regulation*, did not anticipate alternative revenue programs and only referenced incurred costs, not the accrual of revenue, in its definition of a regulatory asset. However, we believe that there is no economic distinction between the two as to the ability and authority of the utility to recover amounts authorized by the regulator and that the existence of a regulatory asset should continue to be based on a probable future revenue stream established by an order from the utility's regulatory commission, regardless of whether the revenue stream is designed to compensate for a previously incurred cost or a completed alternative revenue program. Furthermore, we believe that the revenue recognition project was not intended to change the accounting for regulatory assets by rate-regulated utilities. Based on these facts, we believe this guidance should continue to be applied as part of rate regulated activities and transferred to ASC 980-340, *Other Assets and Deferred Costs,* as recording these regulatory assets fairly represents the economics of completed transactions with our customers and provides meaningful information to investors.

Regulation provides unique nuances that have definite, specific, and very real economic effects, and therefore specific industry related guidance is needed. Utilities provide a service that is considered to be a public necessity and a significant portion of a utility's business operates as a natural monopoly in which it is required to dedicate a considerable amount of investment and financing. In order to encourage and reward the investment, public utility commissions set prices that fund the utility's costs of providing service and provide a fair return on invested capital (referred to as authorized revenue requirement). In addition, utilities enter into franchise agreements with local municipalities which grant exclusive rights to the utility to provide service to an area. This set of compacts creates unique operational considerations as well as an economic dimension that is reflected in the accounting and financial reporting for utilities.

In a conventional/traditional utility regulation model, utility revenues and profits are linked to unit sales in which a loss of sales due to successful implementation of energy efficiency will lower utility profitability. Utility regulators have a growing interest in energy efficiency and conservation for varying reasons, including public policy, and the regulator can eliminate this sales incentive/efficiency disincentive by decoupling revenues from sales or providing economic incentives to shareholders for providing energy efficiency programs. Regardless of the method of addressing this issue, the recovery of these economic benefits by the utility through its regulated prices is mandated by the regulator and binding on the utility's customers. Without the retention of the guidance in EITF 92-7, the industry would lose guidance for increasingly prevalent transactions.

One example of decoupling revenue from sales is a utility's authorized recovery of costs associated with generating electricity for customers, including capital and related non-fuel operating and maintenance expenses without regard to the volume of generation sales. The regulator continues to allow for the utility to recover its cost of investment in the generation assets and prescriptively requires the utility to record as revenue the full amount of the authorized revenue requirement and to record a regulatory asset for any shortfall in revenue billed to customers.

An example of the regulatory incentive ratemaking mechanism is an incentive award granted by the local regulator to a utility for achieving energy efficiency targets. Regulators can establish incentive ratemaking mechanisms to further encourage utilities to successfully implement energy efficiency programs. The programs are typically utilized to encourage and measure energy efficiency of the utility's customers. If energy efficiency targets are achieved, the regulator will provide financial rewards to the utility in the form of award grants to be collected from ratepayers through an increase in rates in the year(s) following the award grant date.

We recognize that the Boards' objective in issuing the ED is to increase the consistency of revenue recognition for similar contracts, regardless of industry, and improve comparability of revenue recognition practices across industries. The guidance in ASC 980-605-25 enables the utility industry to retain consistency for preparers and comparability for financial statement users, which was the original objective of issuing the guidance in EITF 92-7, and one of the objectives of the Boards' revenue recognition project. We are issuing this comment letter because we believe it is critical for the final standard to ensure that consistency and comparability are not diminished by an unintended consequence of this proposal. We expect rate actions addressed through decoupling and incentive awards to increase significantly in the future as regulators implement energy efficiency policies across the nation. In order for a utility's financial statements to be faithfully represented and consistent with concepts of rate regulated enterprises, the effects of the rate actions addressed through decoupling and incentive awards should continue to be recognized as regulatory assets. Such accounting is logical and provides a proper matching of income with the performance of the service to the customer.

Responses to Questions in the ED

Question 1: *Paragraphs 12-19 propose a principle (price independence) to help an entity determine whether to:*

a) *Combine two or more contracts and account for them as a single contract;*
b) *Segment a single contract and account for it as two or more contracts; and*

c) *Account for a contract modification as a separate contract or as part of the original contract.*

Do you agree with that principle? If not, what principle would you recommend, and why, for determining whether (a) to combine or segment contracts and (b) to account for contract modifications as a separate contract?

We are concerned that the proposed guidance on contract modifications does not properly reflect the economics of the transaction. For example, a common type of contract modification in the energy industry is referred to as a "blend-and-extend" modification. This type of contract modification represents the extension of long-term power purchase agreements (PPAs) and blending the current contract price with the market price of the extended term. The rate for the extension term is based on the market price for such term; however the fixed price per unit of product (megawatt hour (MWh) for the quantities to be sold during the term of the modified contract blends the rate of the remaining term under the original contract with the market rate for the extended term. The example below illustrates a blend-and-extend modification:

> Seller enters a wind PPA in 2000 to sell energy to Buyer through 2023. In 2010, both parties to the contract wish to extend the contract for another 5 years through 2028. Additionally, the parties want to change the contract price for the remaining term through 2028. No cash will be exchanged upon restructuring. The current pricing is a fixed price of $39 per MWh delivered (market price at inception of the contract). The market price for the extension period is $75 per MWh. The new contract price will be a fixed price of $44 per MWh, representing a blend of the $39 and $75 rate. The net present value of the extended contract at $39 per MWh through 2023 and $75 per MWh for the period 2014 – 2028 is not significantly different from the extended contract at a flat rate of $44 per MWh. Such pricing is the economic equivalent of pricing the new volumes at market while retaining the original price for the remaining volumes under the original contract; blending the price is simply a convention to provide the customer with an overall fixed price for the remaining term.

Considering the proposed guidance for contract modifications and the examples in paragraph IG3 of the Implementation Guidance and Illustrations, our interpretation is that for the example above, even though the rate for the extension period is considered a market rate for such term, the new modified fixed price does not reflect the standalone selling price for the modified contract based on current market conditions (i.e., the overall contract is still below market price as of the time of the modification) and therefore the pricing in the existing contract and the modification would be interdependent. In this case, the cumulative effect of the contract modification will result in an increase in previously recognized revenue, presumably requiring Seller to recognize a gain in the current period. We do not believe this reflects the economic substance of the transaction, because Seller is in the same economic position before and after the modification with respect to the quantities under the original contract term. When Seller entered into the original contract, the negotiated fixed price per MWh was based on the standalone selling price or market price at that time. Entering a contract extension today at market rates should have no impact on the portion of the contract that has already been executed. We believe the same would be true if the current market price were lower than the original contract price and resulted in a blended rate that was lower than the original contract price. Unless specifically identified as relating to a past event, the results of contract modifications represent the agreement between the buyer and seller relating to future transactions and, accordingly, should be accounted for prospectively.

There exists little to no accounting guidance in U.S. generally accepted accounting principles (US GAAP) related to modifications of executory contracts. We encourage the Boards, either in this project or a separate one, to provide much needed guidance beyond what is included in the ED. Areas that should be addressed include the effect of cash payments in modifications, partial contract terminations, the circumstances under which the effect of modification should be recognized in the financial statements, when previously recognized amounts (for example, resulting from business combination accounting) related to modified contracts should be derecognized, and the symmetry in accounting between the parties to an agreement.

Question 2: *The Boards proposed that an entity should identify the performance obligations to be accounted for separately on the basis of whether the promised good or service is distinct. Paragraph 23 proposed a principle for determining when a good or service is distinct. Do you agree with that principle? If not, what principle would you specify for identifying separate performance obligations and why?*

We ask for clarification on the basis for evaluating contracts that contain multiple products or elements, some of which may be leases, derivatives and others of which may be non-derivatives and non-leases. The difficulty arises in whether to first apply the requirements of Topic 840, *Leases*, Topic 815, *Derivatives and Hedging* or the proposed revenue recognition guidance of identifying separate performance obligations. We also seek some clarification or amendments regarding the conditions included in paragraph 23(b) for determining when a product is "distinct," particularly as it relates to the accounting for renewable energy credits (RECs).

Accounting for multiple deliverable arrangements

We are concerned that guidance in determining how to account for a contract that has multiple elements or separate performance obligations differs across current accounting standards as well as across the EDs on Revenue Recognition, Accounting for Financial Instruments and Revisions to the Accounting for Derivative Instruments and Hedging Activities and Leases. There is currently divergence in practice in accounting for multiple elements and we believe that divergence will continue in accounting for separate performance obligations. Therefore, we are asking for clarity as well as more consistency across proposed standards.

Paragraph 6 of the ED scopes out lease contracts as well as contractual rights or obligations within the scope of Topic 815, *Derivatives and Hedging* (Topic 815). We believe that there are contracts that contain derivative and non-derivative components as well as contracts that contain lease and non-lease components. For that reason, we do not believe that a contract should be completely scoped out of the revenue recognition guidance.

Below are examples of where divergence in practice exists, or could exist, due to inconsistent guidance:

Revenue Recognition and Derivatives and Hedging

Contracts in our industry often include more than one energy-related product, such as energy, capacity, RECs, ancillary services, or some combination of these. Depending upon the market in which the transaction occurs, some of these products may meet the definition of a derivative (primarily because they have the characteristic of net settlement due to transacting in a market in which they are readily convertible to cash) while other products in the same contract do not. However, the business purpose of these transactions is the provision of energy, which is generally a derivative. Also, the derivative energy component usually makes up most of the relative value of the contract. These contracts are common in the industry, are designed to meet the needs of the customer and are not structured to combine products in order to achieve a desired accounting result.

When determining how to account for a contract, we generally apply the requirements of Topic 815 due to the business purpose of these transactions being the provision of energy, which is typically a derivative. The following are alternative views as to how to account for a contract that includes the sale of energy, capacity, ancillary services, and RECs:

- Apply Topic 815 and, if the contract is determined to be a hybrid contract, and further if the host element of the contract is determined to be a derivative, then the bundled contract in its entirety is accounted for as a derivative.

- Apply Topic 815 and if the contract is not determined to be a derivative in its entirety but does contain a derivative element (i.e., a multiple element contract) (generally, the energy would be accounted for as a derivative), account for the derivative element of the contract using Topic 815, and account for those elements that are not derivatives under applicable GAAP, inclusive of revenue recognition guidance. Consideration would be given to whether any of the non-derivative elements contain embedded derivatives (i.e., terms that affect some or all of the cash flows or the value of other exchanges required by the contract/element in a manner similar to a derivative instrument).

- Apply Topic 815 and if the contract is not determined to be a derivative in its entirety and does not contain any elements that are derivatives, account for the contract using other applicable GAAP which may include revenue recognition guidance.

- Apply revenue recognition guidance to identify separate performance obligations. Each identified separate element should then be accounted for under applicable GAAP, inclusive of revenue recognition guidance.

As stated above, Paragraph 6 of the ED, that defines scope, states that *the proposed guidance applies to all contracts with customers except…(v) Topic 815 on Derivatives and Hedging.* The alternative views above demonstrate that although we would apply Topic 815 first, we may also have to apply the revenue recognition guidance to other non-derivative elements in a contract, however, Topic 815 has frequently been viewed as a "contract-based" standard with very little latitude for separating and accounting for non-derivative elements outside of the hybrid instrument accounting model. Because of the lack of clarity regarding the interaction of the ED and Topic 815 for contracts that have multiple-elements or separate performance obligations and the divergent accounting that can result from the alternative views, we believe that it would benefit users and preparers of financial statements for the Board to clarify its views on this issue in each of the exposure drafts.

Revenue Recognition and Leases
As stated above, Paragraph 6 of the ED, that defines scope, states that *the proposed guidance applies to all contracts with customers except…(a) lease contracts within the scope of Topic 840 on leases.* Paragraph 6 of the Leases (Topic 840) ED states that *an entity shall apply the lease guidance except as follows: A lessee/lessor shall apply the exposure draft on revenue from a contract with customers to a service component of a*

contract that contains service components and lease components if the service component is distinct and the lessee/lessor is able to do so.

The ED scopes out lease contracts and we believe that the Leases ED does not fully address which guidance to apply in cases where there are separate contract components. For example, a contract for renewable energy may contain a lease component, a service (non-lease) component, and additional non-service components such as the sale of energy or RECs. If one component is determined to be a lease, the lease guidance refers you to the revenue recognition guidance for the service component. There is no reference or guidance for components or additional elements of a contract that are not determined to be a lease or a service component (the sale of energy or RECs in this example). We believe that it would benefit users and preparers of financial statements for the Board to clarify its views on this issue in each of the exposure drafts.

We believe that the preferable approach would be to specify in the EDs to refer to the revenue recognition guidance to identify and separate performance obligations in contracts prior to applying the applicable guidance to each separate performance obligation. We also believe that revenue recognition guidance should not fully scope out contracts that contain derivative or lease components.

Renewable Energy Credits

We suggest that the required conditions in paragraph 23(b) that are necessary for goods or services to be deemed distinct should be included as guiding principles or indicators and not be the rule. We believe that a product or service could be distinct if it has a distinct function, even though it does not have a distinct margin. For example, a REC secondary market exists that facilitates REC purchases and sales. However, certain states have market restrictions on separate sales of RECs (i.e., cannot be sold separately from the energy) and therefore these RECs would not meet the separate sale definition of distinct in paragraph 23(a). Due to it being a by-product of generating energy, it might not have a distinct profit margin and therefore would not meet the definition of distinct per paragraph 23(b) of the ED either, even though it has a distinct function and has standalone value to the customer. We noted in the Background and Basis for Conclusions section paragraph BC 53 that the Boards had concerns that requiring an entity to estimate a selling price for a good or service that does not have a distinct profit margin, even if it has a distinct function, might result in information that would not be useful to users of financial statements. We do not believe that this concern is valid in the REC example described above. Due to the existing secondary REC market selling prices are readily available and therefore would not have to be estimated.

In consideration of the above, we suggest that the Boards include the conditions in paragraph 23(b) as guiding principles and/or indicators, or that the Boards consider adding the presence of a secondary market as an alternative requirement to meeting the distinct profit margin requirement.

Question 5: *Paragraph 43 proposes that the transaction price should reflect the customer's credit risk if its effects on the transaction price can be reasonably estimated. Do you agree that the customer's credit risk should affect how much revenue an entity recognizes when it satisfies a performance obligation rather than whether the entity recognizes revenue? If not, why?*

We do not agree with the credit risk model proposed by the ED. In our view, the existing model which includes the recognition of bad debt expense separately from revenue provides the most transparent view of a company's revenue and credit exposure. The requirement to record credit risk as a reduction of revenue makes it difficult for users of the financials to understand a company's collection practices and changes in the credit quality of its customers. Credit losses have also traditionally been viewed as costs so this would be a departure from well established and, in our view, well functioning guidance.

The prices charged to customers are not adjusted to reflect the customers' credit profiles. In the regulated utility industry, the rates charged to customers by the utility are fully mandated by regulators. The rates are recognized as revenue based upon customer usage and are compared with utility expenses to ensure that the utility is earning an authorized return. If that return is not sufficiently earned, the utility requests an increase in the rates charged. In addition, the recovery of uncollectibles is also mandated by the regulators. As such, the utility industry already has a built-in approach (rate-based model) for addressing credit risk.

The recognition of the collection of an item previously deemed uncollectible through other income is not appropriate if the initial credit consideration was recorded as a reduction to revenue. This treatment is not indicative of the true economics of the contract, and it will result in the lack of recognition of valid revenue within that line item.

Therefore, we believe that the continued recognition of credit risk as a separate expense is the most transparent presentation for the cost of uncollectible accounts. It should also be noted that this proposed provision is not consistent with the credit impairment model in the proposed guidance for financial instruments. Specifically, the Financial Instruments exposure draft states that entities should consider past events and existing economic conditions in determining credit risk. The ED states that entities should consider the amount the entity expects to receive from a customer using a probability weighted estimate. As such, we ask that the Boards remove this provision from the final revenue recognition standard.

Question 9: *Paragraph 58 proposes the costs that relate directly to a contract for the purposes of (a) recognizing an asset for resources that the entity would use to satisfy performance obligations in a contract and (b) any additional liability recognized for an onerous performance obligation.*

Do you agree with the costs specified? If not, what costs would you include or exclude?

We do not agree with the proposed guidance pertaining to the recognition and measurement of onerous performance obligations contained in paragraphs 54-56 of the ED. First, in order to implement this provision, we believe that clarification is needed since the guidance does not clearly state whether the requirement to record an onerous performance obligation applies only to performance obligations recorded as contract assets or liabilities on the balance sheet or to all performance obligations (i.e., including those related to a contract under which neither party has performed, such as an unrecognized executor contract). We ask that the Boards specifically clarify in the final standard whether the onerous performance obligation provisions apply to all performance obligations or only to those performance obligations already recognized on the balance sheet.

In addition, the onerous performance obligation provisions introduce additional complexity and administrative requirements that the Boards considered and ultimately rejected on a similar issue within the Exposure Draft. Paragraph BC131 explains, "In the Discussion Paper, the Boards noted that the amount of an entity's performance obligations could change for reasons other than an entity's performance (for example, for changes in the price or quantity of goods or services that an entity expects to transfer to the customer to satisfy its remaining performance obligations). The Boards also noted that reflecting those changes in the measurement of the performance obligations would require an entity to remeasure its performance obligations at each reporting date. In the Discussion Paper, <u>the Boards rejected such an approach because they concluded that it would be unnecessarily complex for most contracts with customers</u>" [emphasis added]. We agree with the Boards' original intent to exclude the requirement to remeasure performance obligations each quarter. However, we believe that the requirement to periodically assess performance obligations and determine if they have become onerous essentially involves the same burdensome remeasurement requirement that the Boards attempted to avoid. This provision introduces additional administrative and operational issues and we believe that the costs of implementing such a provision in our industry outweigh the benefits as discussed more fully below.

We believe that many companies will have a difficult time implementing these provisions from an operational standpoint. Specifically, companies that use a portfolio approach to manage their business will find it challenging to disaggregate and directly link the costs associated with satisfying specific performance obligations in order to determine if an onerous performance obligation exists. For instance, an nonregulated power supplier that serves millions of retail power customers may procure power from a variety of different sources including owned generation, contracted generation (e.g., leased assets), and through bilateral purchase agreements. Since the power supplier manages its revenues and expenses in the aggregate, there is no distinct link between the revenue generated from a single contract and the cost associated with the supply of power sourced and dedicated to serve that individual customer. Moreover, due to the nature of the commodity, it is impossible to identify which electrons of power (i.e., from owned generation vs. a power purchase agreement) were used to serve that customer.

Further, the time periods for the performance obligations under contract do not necessarily correspond to the time period(s) in which obligations may be economically hedged (e.g., a company may be 90% hedged for expected sales in the current year, 70% hedged one year out, 50% hedged two years out, etc.). Thus, for the unhedged portions of our contractual performance obligations we are exposed to changes in commodity prices which could impact the onerous contract assessments each period. Because of these factors (i.e., the effort involved in directly linking supply resources to individual performance obligations and the exposure to changing commodity prices in order to satisfy these performance obligations), companies in our industry would incur substantial costs to comply with these provisions.

Finally, the notion of recording an onerous performance obligation that potentially stems from temporary market changes is, in our view, erroneous. In our industry, the costs to serve commodity-based contracts fluctuate with market prices and it would present misleading results if a company were to recognize an onerous performance obligation based on a temporary change in market prices and subsequently realize a profit on the same contract. Applying such a provision would cause unnecessary income statement volatility resulting from (a) recording temporary onerous performance obligations based on changes in commodity prices that ultimately reverse, and (b) recording an onerous performance obligation for only a portion of a contract without the ability to record an offsetting favorable performance obligation within the same contract while the overall contract remains profitable throughout the entire duration of the contract (i.e. there never is and never will be a realized loss). The asymmetrical results stemming from the application of the onerous performance obligation provisions cloud the transparency that the exposure draft seeks to achieve. In consideration of the above, we suggest that the Boards remove the onerous contract provision in its entirety.

While we believe that removing the onerous performance obligation as recommended above is the most appropriate resolution of this issue, we recognize that the Boards may determine to retain that proposed requirement. In the absence of removing the onerous performance obligation provision entirely, we ask that the Boards consider modifying the proposal as follows:

- Raise the level of measurement to the overall contract level from the individual performance obligation level. The commercial decision to enter a contract should be the basis for measurement, not whether individual elements within the contract are profitable. Furthermore, we do not believe that there can be precision on the allocation of the transaction price to account for an onerous contract at a lower level. Finally, measurement of onerous contracts, instead of onerous performance obligations, will minimize operational costs and limit income statement volatility;
- Clarify whether aggregation of contracts is permissible when a company uses a portfolio management approach; and
- Clarify that the costs/benefits provided by hedges, for example forward supply contracts, options, swaps, etc., are included in the Proposed Update's definition of "contract costs." In other words, we believe that the cost to fulfil a customer sales contract should include the impacts of specific hedges associated with securing the supply of product to satisfy the performance obligation.

Question 11: *The Boards propose that an entity should disclose the amount of its remaining performance obligations and the expected timing of their satisfaction for contracts with an original duration expected to exceed one year.*

Do you agree with that proposed disclosure requirement? If not, what, if any, information do you think an entity should disclose about its remaining performance obligations?

We support the proposed new disclosure requirements, with the exception of the proposal to disclose future remaining performance obligations and the expected timing of their satisfaction as we do not believe that the potential benefits to financial statement users justify the cost to prepare this.

Financial statement preparers may need to gather and maintain a significant amount of data solely to comply with this disclosure requirement. The amount of information that would need to be tracked for the disclosure is both more extensive than what is currently required under US GAAP and more extensive than what is needed to understand the accounting under the proposed guidance.

Also, preparers may need to make judgments about contingent revenue and timing of the satisfaction of future performance obligations several years into the future which may cause significant changes in the data presented from period to period. Therefore, the actual amount of revenues earned in a future period would unlikely be equal to the amount disclosed in the future performance obligations table. We are concerned that financial statements users may interpret the disclosed amount of future revenues related to existing performance obligations to be the amount of guaranteed future revenues in each period as opposed to our current probability-weighted estimate of future revenues in each period. Similarly, we are concerned that some users may interpret the amounts disclosed as the total revenues expected in future years, as opposed to expected revenues for existing contracts. In addition, management develops long-term revenue and earnings forecasts for the company that are based on expected revenues under existing and future contracts, and as such, the forecast information which is often provided to investors will not be based on the same revenues as the disclosure, which may lead to confusion among our investors and other financial statement users. This type of forward-looking information would typically be included in Management's Discussion and Analysis, and its inclusion in the footnotes will increase potential litigation risk to companies.

Therefore, the cost to prepare the information required to comply with this disclosure may be burdensome, and we believe that this information may be confusing and will not provide any direct benefits to financial statement users.

Question 13: *Do you agree that an entity should apply the proposed guidance retrospectively (that is, as if the entity had always applied the proposed guidance to all contracts in existence during any reporting periods presented)? If not, why?*

Is there an alternative transition method that would preserve trend information about revenue but at a lower cost? If so, please explain the alternative and why you think it is better.

We support prospective adoption of this proposed guidance and do not agree that the benefits outweigh the costs and impracticality of applying these changes retrospectively. Companies will need adequate time to prepare for these changes and respond to unforeseen challenges in a variety of industries. This will include substantial information system changes that will be difficult to implement retrospectively. Retrospective application will also cause companies to incur unnecessary costs in revising and auditing previously reported information. They would need to run two separate revenue recognition systems in tandem during a transition period, and they would have to address internal control and documentation issues under each system which will prove confusing and redundant.

The amount of revenue recognized is based on significant judgment made in real time such as the determination of, and satisfaction of, performance obligations, and the assessment of collectibility. These decisions would be difficult to recreate and/or record for prior periods. For example, in applying retrospective evaluation, should preparers use hindsight, or should the estimates utilized at the time be used to reperform the revenue recognition under a new method?

We are also concerned that a cumulative adjustment will create confusion for users of the financial statements, including analysts and investors. For example, if revenue is effectively recognized in a previous period (through retained earnings) due to a cumulative adjustment, the prior period income statement would not reflect this revenue earned. This would impact trend analysis. Our industry has a number of transactions under which revenue is deferred over long-term periods and we are concerned that a cumulative effect adjustment would adversely impact income statement trend analysis.

Therefore, we believe that prospective adoption is preferred and appropriate. Adjusting revenue recognized, which is dependent on judgments made at the transaction date, is costly and susceptible to error in application, and potentially confusing to financial statement users. Adequate disclosure should be made available to inform the reader of differences in recognition of revenue between current and revised guidance and will help the reader to better understand the implementation of changes in the recognition of revenue.

Conclusion

We appreciate your consideration of this topic and our related comments. The proposed changes to revenue recognition will have a significant effect on all industries, and we would be pleased to discuss the impact on our industry with you and to provide any additional information that you may find helpful in addressing these important issues.

Very truly yours,

David K. Owens

David K. Owens

DKO/ds

(END OF ATTACHMENT)