

September 1, 2011

TO: Membership of the Society of Depreciation Professionals

FROM: John Ferguson, Current Issues Editor

The purpose of the Current Issues letters is to inform the Society membership on depreciation related issues. The views expressed in the letters are the views of the authors and do not reflect any formal position of the Society. The Society hopes that these letters will prompt discussion among members and lead to an increased understanding of the issues facing our members. All members are encouraged to submit their ideas and comments for consideration in a future letter. Comments should be addressed to John Ferguson (johnferg@swbell.net). The letters are distributed to members via email and each is posted on the SDP web site (www.depr.org). All prior Current Issues letters are posted on the members-only section of the Society web site. Therefore, any prior letter mentioned by this letter is available to members.

Decommissioning Funding for the Vermont Yankee Nuclear Station

Several of these periodic Current Issues letters have addressed an effort by Vermont to prevent this station from operating beyond its original operating license termination date of March 21, 2012. Following the recent recession, during which the Vermont Yankee decommissioning fund sustained an \$84 million loss, Entergy agreed to a \$40 million guarantee by the parent firm to assure that decommissioning would meet the requirements of the Nuclear Regulatory Commission (NRC). The fund currently contains \$211 million in excess of the minimum NRC requirement, without considering the guarantee, and Entergy requested that the guarantee be canceled. The NRC refused to do so, saying that uncertainty concerning the station's future makes cancellation at this time premature, and that Entergy may resubmit its request after the lawsuit mentioned by the May 18, 2011 letter (page 1) has been resolved.

Carbon Capture and Sequestration Technologies

The discussion of this subject by the August 4, 2011 Current Issues letter (pages 1 and 2) states that the editor-in-chief in the July 2011 issue of Power addresses a lack of any substantial work on either the cost or the policy formulations for interstate transportation of CO₂ from scattered sources to central injection points and notes that the U.S. Department of Transportation has primary authority to regulate CO₂ pipeline safety and considers CO₂ to be a hazardous material. The Environmental Protection Agency recently issued a proposed rule for comment that would exclude from hazardous waste regulations captured CO₂ streams that are injected into underground wells designed for geologic sequestration. The proposed rule is stated to be complementary to a recently finalized Safe Drinking Water Act rule that sets requirements for geologic sequestration, including the development of a new class of injection well.

25th Annual Meeting of the Society

This meeting will be in Atlanta on September 19 and 20, 2011 and will include the usual accounting update by John Lacey and presentations addressing:

- Regulatory perspective on depreciation;
- Ratemaking challenges and remedies;
- Implications on cost of capital;
- Theoretical reserve imbalances and impact on regulatory reporting and accounting;
- Depreciation methods and revenue requirements; and,
- Implications of International Financial Reporting Standards on depreciation, with emphasis on componentization.

Modified International Financial Reporting Standards in Canada – Prepared by Society Member Frank D’Andrea, CA

As required by the Canadian Accounting Standards Board (AcSB), Canadian Generally Accepted Accounting Principles (CGAAP) for publicly accountable enterprises transitioned to International Financial Reporting Standards (IFRS) effective January 1, 2011. Pursuant to an AcSB pronouncement in September 2010, rate-regulated Canadian utilities have the option and can elect to delay the effective date of transition to January 1, 2012.

The adoption of IFRS is expected to change the manner in which Canadian utilities perform their accounting and reporting of financial results, and this may create impacts for customer rates. Canadian regulatory boards do not prescribe the financial reporting for regulated utilities, but they do set the requirements for regulatory accounting, reporting and filing.

In light of the transition to IFRS, regulatory oversight boards, most notably in Ontario and Alberta, have undertaken consultation sessions with key stakeholders and have issued guidance on how to *modify* IFRS (MIFRS in Ontario and Rule 26 in Alberta) for purposes of setting rates. For Ontario, see:

[http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/International+Financial+Reporting+Standards+\(IFRS\)](http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/International+Financial+Reporting+Standards+(IFRS))

For Alberta, see:

<http://www.auc.ab.ca/items-of-interest/ifrs/Pages/default.aspx>

Regulatory Assets and Liabilities

Much has been debated in accounting circles about whether IFRS allows for the recognition of regulatory assets and liabilities. As controversial a topic as this has been, European, Australian and other rate-regulated utilities have fallen short in this pursuit, and upon adoption of IFRS, defaulted to having to write-off these assets and liabilities on day one of their transition.

Canadian utilities have resurfaced this issue with the AcSB, as well as the International Accounting Standards Board, in their transition work, citing that the nature of regulation in North America is largely cost-of-service (COS) based and thus warrants recognition unlike their counterparts in European and Australia (India is also largely COS regulated). Again, these arguments have fallen on deaf ears. The standard setters have stayed true to the argument that rate-regulation is only a form of pricing, and thus is separate from the concept of recognizing regulatory assets and liabilities (amounts to be collected or refunded to customers, respectively).

Regulators in Ontario and Alberta have tried to support Canadian utilities in their pursuit, as they would, of course, desire consistency between financial and regulatory reporting. However, the concept of reporting regulatory assets and liabilities is distinct from whether the regulatory boards should, in fact, continue to use these accounts.

The Canadian regulators are clear that rate making must deal with uncertainty and with circumstances that are difficult to forecast and may be beyond a utility's control. In these circumstances, the boards view deferral and variance accounts as key regulatory instruments to protect the interests of both utilities and ratepayers and also reduce overall costs. In summary, the boards will continue to use deferral and variance accounts under MIFRS or Rule 26 as appropriate, whether or not these accounts are recognized under IFRS. As a minimum, this creates dual reporting requirements for utilities.

Property, Plant and Equipment (PPE)

IFRS has a separate standard for PPE, as well as separate standards for the capitalization of borrowing costs and impairment. Aside from the controversy over if and how regulatory assets and liabilities should be recognized under IFRS, clearly PPE has presented the most challenge for Canadian utilities in terms of how to apply specific provisions. Some of the following applications are particularly noteworthy.

1. Cost of PPE

Under IFRS, the cost of an item of property, plant and equipment comprises the purchase price and any costs *directly attributable* to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The cost also includes estimated costs of dismantling and removing the asset and restoring the site on which it is located. IFRS goes on to identify examples of what is (and also what is not) directly attributable.

It is fair to say that what is directly attributable varies significantly among utilities, with some capitalizing more than others. The issue is whether costs permitted by the regulator to be capitalized should form the cost of PPE (as they are directly attributable by virtue of the regulator's decision, cost studies, etc.), despite that they would not qualify for capitalization under IFRS.

Regulators in Ontario and Alberta have required utilities under MIFRS to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes

after the date of IFRS. Utilities are also required to file a copy of their capitalization policy.

Recognizing that including less cost in PPE will in turn put pressure on rates, the Canadian regulators have put the onus on the utilities to mitigate any resulting rate impacts.

2. Depreciation

As is common with utilities and several other capital-intensive industries, group depreciation is commonly followed for PPE for purposes of both financial reporting and rate making.

In its conversion efforts, Canadian utilities argued that group depreciation practices were still a systematic and rational basis (using IFRS language) for allocating the costs of PPE to future periods. However, much resistance was encountered from the large accounting firms and, in the end, group depreciation was viewed as being incompatible with IFRS. The accounting rationale for this decision rests on the fact that gains and losses on asset retirements are not recognized directly in the financial results of the utility under group depreciation.

Canadian regulators have recognized this issue and have resolved that the utilities should continue to use the straight-line method of depreciation (group is still a form of straight-line). In Ontario, the regulator has facilitated the issue of depreciation by facilitating a joint depreciation study, the aim of which was to determine depreciation methodologies and rates that would be applied for purposes of setting rates and regulatory reporting, giving due weight to IFRS requirements regarding depreciation, including componentization.

Componentization has a specific meaning under IFRS. PPE may have significant parts with different useful lives. Depreciation is calculated based on each individual part's life. Significant parts that have the same useful life and depreciation method may be grouped in determining the depreciation charge.

Having accepted that there needs to be componentization under IFRS, much too has been discussed on whether the Equal Life Group (ELG) method could still be permissible under IFRS, as opposed to the Average Service Life (ASL) method. For example, some have argued that each component can be depreciated using an ELG determined rate reflective of expected retirements for those items of PPE. The underlying rationale rests on the inability to reliably identify separate lives of grouped assets such as poles, and historical data which suggest that the PPE in question does not retire on a straight-line basis.

Since asset retirements tend to mirror various dispersion curves, the argument is that ELG depreciation rates appropriately reflect these expected retirement patterns. Of course, this claim would need to be supported by periodic testing through annual technical updates. To date, the proposition of using ELG has not rendered any more success in avoiding the

recognition of premature asset retirement losses and, as such, is viewed as being incompatible with IFRS.

In summary, IFRS would require a unit-specific depreciation methodology as opposed to a group depreciation methodology. Since gains or losses on retirements would be recognized under IFRS using unit-specific depreciation, the regulators have also requested that Canadian utilities separately identify these gains or losses on retirements in future rate filings under MIFRS.

3. Customer Contributions (CC)

Utilities typically receive customer contributions (CC) related to PPE, for which financial reporting and regulatory reporting would treat CC as an offset to the cost of PPE, i.e., the utilities would report PPE net of the CC. IFRS requires CC to be recorded as revenue or deferred revenue, depending on the circumstances, instead as an offset to capital cost. The issue of whether CC is revenue or deferred revenue has been much debated, although there is a leaning toward deferred revenue treatment.

For Canadian regulatory reporting and rate making purposes, the amount of CC will be treated as deferred revenue for MIFRS purposes, to be included as an offset to rate base and amortized to income over the life of the facility to which it relates. This reclassification for regulatory purposes preserves the continuity of the rate base.

4. Major Inspections

Continued operation of an item of PPE may require regular major inspections for faults, regardless of whether parts of the item are replaced. When each major inspection is performed, its cost is recognized for IFRS purposes in the carrying amount of the item of PPE as a replacement, if the recognition criteria are satisfied. If necessary, the estimated cost of a future similar inspection may be used as an indication of what the cost of the existing inspection component was when the item was acquired or constructed.

US GAAP is somewhat similar to IFRS, though an entity can choose among available treatments: major inspections and overhauls can be expensed as incurred (“direct expensing method”) or capitalized and amortized to the next major inspection or overhaul (“built-in overhaul” and “deferral” methods). The concept of capitalizing major inspections is foreign to CGAAP, and regulators in Canada did not specifically address the issue in its assessment of MIFRS. This suggests that capitalization of these costs were not an industry-wide issue, though one might have expected this to be case as ultimately a return on rate base would be earned on such amounts.

As a word of caution, in their transition efforts, Canadian utilities did have to determine what constitutes a “major” inspection, as there is considerable judgment involved. In assessing whether the inspection is “major,” generally Canadian utilities looked to the general capitalization criteria, and whether said inspections were externally imposed (mandatory), such that failure to inspect would/could result in an inability or impairment in our ability to operate the equipment. In most cases, periodic asset condition inspections are performed to justify work program requirements for the regulator and to

prudently and safely operate the system, but they are not mandatory. Under these circumstances, most inspections would not qualify as “major” and would not be capitalized.

5. Impairment

There is a general presumption that rate base for PPE is equivalent to fair value of PPE for accounting and reporting purposes. This presumption is based on the fact that fair value reflects only that which can be recovered from ratepayers, and even if sold outside the utility, the PPE would garner cash flows equivalent to rate base, since (generally speaking) only another utility would purchase the PPE.

An exception to the general presumption is specific disallowances (say for prudence) by the regulator. In this case, regulatory accounting and financial accounting and reporting would indicate the PPE is impaired and should be written down, i.e., to the amount the regulator dictates is recoverable. MIFRS would retain this accounting.

Under IFRS, impairment is judged at the individual asset level where specifically identifiable cash flows exist; otherwise, impairment is tested at the transmission or distribution level as an example (termed the cash generating unit or CGU). Thus, if the PPE in question is part of the grid and connected to other assets providing power, then impairment should be judged at the higher CGU level. It is not hard to conceive an example (because of the added return from other assets) where there would not be impairment at the CGU level. This counterintuitive result then creates disparity, since the PPE is written down for Canadian regulatory purposes under MIFRS, but not under IFRS.

Summary

There are other differences between IFRS and MIFRS, each of which needs to be closely examined by the utility, as the regulator’s objectives in setting rates do not necessarily coincide with financial reporting requirements. For example, almost all Canadian utilities report cash or flow-through taxes currently for regulatory and financial accounting and reporting. MIFRS retains the cash basis, as it preserves the traditional premise that ratepayers should only pay for out-of-pocket taxes. However, a Canadian utility reporting under IFRS would reflect accrual taxes for purposes of its financial accounting and reporting.

Clearly, IFRS will pose challenges for Canadian utilities in many areas of accounting and reporting which have traditionally coincided with their rate making treatments. There will be increased burden on utilities to be able to reconcile IFRS and MIFRS, and each utility will need to consider how to best handle the added dual reporting burden. Most of all, however, there needs to be increased diligence that accounting changes do not necessarily result in increased customer rates, both on the part of the utility and the regulator.

Incorporating International Financial Reporting Standards (IFRS) into U.S. GAAP

A paper by the Securities and Exchange Commission (SEC) Staff, Exploring a Possible Method of Incorporation, was issued on May 26, 2011 for comment as part of the work plan for incorporating IFRS into U.S. GAAP. The paper notes that the Commission has not yet made a decision as to whether and, if so, how, to incorporate IFRS into the financial reporting system for U.S. issuers of securities, and that possible approaches that have been discussed and commented on include:

Full adoption on a specified date, without any endorsement mechanism;

Full adoption following a staged transition over several years; and,

An option for adoption by U.S. issuers in the manner allowed by SEC Release No. 33-8831, Concept Release On Allowing U.S. Issuers To Prepare Financial Statements In Accordance With International Financial Reporting Standards.

The paper also notes that some of the comments on these alternative approaches have suggested that U.S. GAAP be retained with continued convergence efforts, with or without a mechanism in place to promote alignment with IFRS, and addresses such an approach, because it has not been previously described. This convergence approach would retain U.S. GAAP, with the Financial Accounting Standards Board (FASB) incorporating IFRSs over a defined transition period, with a focus on minimizing transition costs, particularly for smaller issuers, through an endorsement protocol that would provide the FASB with the ability to modify or supplement IFRSs when deemed to be in the public interest and necessary for the protection of investors. This convergence approach is different from the current convergence project of the FASB and International Accounting Standards Board (IASB), because this approach goes in only one direction – U.S. GAAP → IFRS – whereas the FASB/IASB convergence project causes GAAP and IFRS to move toward each other.

Comment: A transition period has the potential for creating an unstable financial accounting framework during that time.

The paper segregates the convergence approach with endorsements into the following categories of international standards for discussion purposes:

IFRSs covered by the FASB/IASB convergence project;

IFRSs included on the IASB's current agenda; and,

All other existing IFRSs and areas not addressed by IFRSs.

This convergence approach with endorsements is stated to have the advantage of retaining the existing SEC and FASB authority over U.S. accounting standards, and to share many key features of other jurisdictions' process for incorporating IFRSs into their respective national financial reporting frameworks, with the European Union and Australia being cited as examples of using endorsement processes. Endorsement is stated to be useful for allowing industry-specific guidance not provided by IFRS, such as for oil and gas, airline, and regulated operations.

Comment: IFRSs do not provide industry-specific guidance. In 2009, the IASB published an exposure draft addressing rate-regulated activities. In September 2010, the IASB concluded that it could not resolve that matter quickly and decided to develop an agenda proposal for consideration for its future agenda in 2011. On July 26, 2011, the IASB issued a Request for Views (RFV) on its future agenda setting process:

<http://www.ifrs.org/Current+Projects/IASB+Projects/IASB+agenda+consultation/agenda+consultation+2011/agenda+consultation+comment+letters+2011.htm>

Society member Frank D'Andrea provides this link, and states that Appendix C to that document identifies the IASB's previous project on rate-regulated activities, but does not emphasize any particular pressing need for a standard that would be similar to the FASB's Accounting Standard Codification (ASC) 980, Regulated Operations (previously SFAS 71, Accounting for the Effects of Certain Types of Regulation). Comments on the RFV are due by until November 30, 2011.

The Staff paper mentions the componentization requirement of IAS 16, Property, Plant and Equipment, as being one of the most significant aspects of adopting IFRS, but addresses the issue as being the potential for a need for greater segregation of components than under U.S. GAAP.

Comment: The Staff paper does not disclose any awareness of the difficulty of adopting IFRS by entities required to practice the group concept of depreciation for regulatory accounting purposes. However, the approach addressed by the paper of using an endorsement process could allow IFRSs to be incorporated into U.S. GAAP without precluding the continued use of the group concept and without creating a mismatch between the consumption of fixed assets and the recording of their associated removal costs, if the FASB and SEC develop an understanding of regulatory asset and depreciation accounting or are willing to listen to those who have this understanding, and doing so is supported by international accounting firms. The discussion of the Canadian situation by Mr. D'Andrea in the prior section of this Current Issues letter suggests that the accounting firms are unlikely to support continued use of the group concept.

It will be interesting to see whether those entities currently practicing the group concept will make the effort needed to retain it for financial accounting purposes.

Mr. D'Andrea also provides the following link for those interested in the comments the SEC receives on the Staff paper:

<http://www.sec.gov/comments/4-600/4-600.shtml>

Depreciation Accounting Implications of Changes to the Mode of Operation of Electric Generating Units – Comment

The August 2011 issue of Power includes two articles on the cost and operational implications of changes to the mode of operation of coal-fired generating units due to reduced demand caused by the recent recession, to lower natural gas prices and increased switching from coal to gas, and to increased deployment of intermittent renewable generation sources. The shift in mode of operation is from base load to cycling duty and nearly all coal units were designed for base load operation. Therefore, such a shift will require coal units to operate closer to – or beyond – their nominal design limits and to go through more thermal cycles than originally anticipated, so would decrease unit life spans and increase the frequency of component replacements, both of which influence depreciation. The ability of coal units to shift to cycling duty may be limited by their environmental control equipment, such as scrubbers and catalytic reduction systems, being chemical processes that require stable operation to function properly.

The influence of reduced demand is unlikely to last long enough to affect depreciation, but the other two influences will. The recently developed ability to produce gas from shale deposits has substantially increased U.S. gas reserves, which can be expected to keep gas prices low for a long time, and requirements for intermittent wind and solar resources will not go away.

Shortened life spans will influence both group and component depreciation. An increase in the frequency of component replacements will influence group depreciation, and the extent of its influence on component depreciation will depend on the size of the components selected for component depreciation purposes. Power predicts that shifting coal units to a cycling mode of operation will double the costs for component replacements, which suggests that future depreciation rates reflect double the interim addition and retirement activity than was experienced under base load operation, until such time as cycling duty has been in place long enough to rely on. Gas-fired units that operate in a cycling mode will not provide a basis for the interim additions and retirements suitable for coal units that shift to a cycling mode, because gas and coal units exhibit different rates of interim activity and gas units operating in a cycling mode are likely to have been designed for this service.

Future Costs of Generation Technology Options

A June 2011 report of the Electric Power Research Institute (EPRI), Program on Technology Innovation: Integrated Generation Technology Options, provides the following estimates of future costs for utility-scale generation technologies that EPRI believes are likely to dominate the U.S. generation mix over the next 20 years:

	Book <u>Life</u> years	<u>Levelized Cost</u>	
		<u>2015</u> \$/MWh	<u>2025</u> \$/MWh
Coal			
Pulverized (a)	40	54 - 60	87 - 105
Gasification Combined-Cycle (a)	40	68 - 73	85 - 101
Natural Gas			
Combined-Cycle	30	49 - 79	47 - 74
Combined-Cycle with Carbon Capture	30		68 - 109

Nuclear	40	76 - 87	76 - 87
Biomass	40	84 - 147	80 - 136
Wind			
On-Shore	20	75 - 138	73 - 134
Off-Shore	20	130 - 159	122 - 147
Solar			
Concentrating Thermal	30	151 - 195	116 - 173
Photovoltaic	20	242 - 455	210 - 396

Note (a) The 2025 costs include carbon capture

The costs are generic and in constant December 2010 dollars, include financing costs, and exclude tax credits, loan guarantees or other incentive programs, major refurbishments, decommissioning costs other than for nuclear, and potential penalties for CO₂ emissions. The estimates for the near-term (2010 - 2015) reflect a modest extrapolation of today's technology and foreseeable technology development, and for the longer-term (2020 - 2025) assume that established research and development objectives are reached and reflect reductions in costs from potential technology improvements.

The report presents sensitivity analyses for levels of penalties for CO₂ emissions up to \$50/metric ton, which impact the coal and natural gas options and show them to remain less costly than the wind and solar options and the more costly biomass fuels.

Comment: The report indicates that improved technology over the next 20 years will be insufficient for the wind and solar options to be viable without subsidies.

CO₂ Emission Reduction Benefits of Wind Power

BENTEK Energy has released a study, The Wind Power Paradox, that asserts wind industry and political advocates have overstated the CO₂ emission reduction benefits of wind power. The study relies on EPA data for four regions, asserts that the wind power CO₂ reduction per MWh in Texas is only 21% of the reduction claimed by the American Wind Energy Association and the nitrous oxide reduction is only 30%, and concludes that wind is not a cost-effective solution for reducing CO₂, if carbon is valued at less than \$33/ton.

Michigan Case No. U-16117 of the Detroit Edison Company

This is the first electric depreciation proceeding required by the order in Case No. U-14292 that addressed adoption of SFAS 143, Accounting for Asset Retirement Obligations, and the treatment of salvage and cost of removal not qualifying for SFAS 143. The testimony in Case No. U-16117 is addressed by the December 15, 2010 Current Issues letter (pages (8 - 18) and the Proposal for Decision is addressed by the May 18, 2011 letter (pages 1 - 3). This discussion is prompted by the Order and addresses only the differences from the Proposal for Decision.

The aspects of the Proposal for Decision rejected by the Order are the 20% contingency adopted for the power plant demolition estimates and the need for closure of an ash pond.

The Order changes the contingency to 10% and eliminates the closure costs, both of which decrease the non-nuclear power plant demolition cost estimates and the related depreciation rates inherent in the Proposal for Decision.