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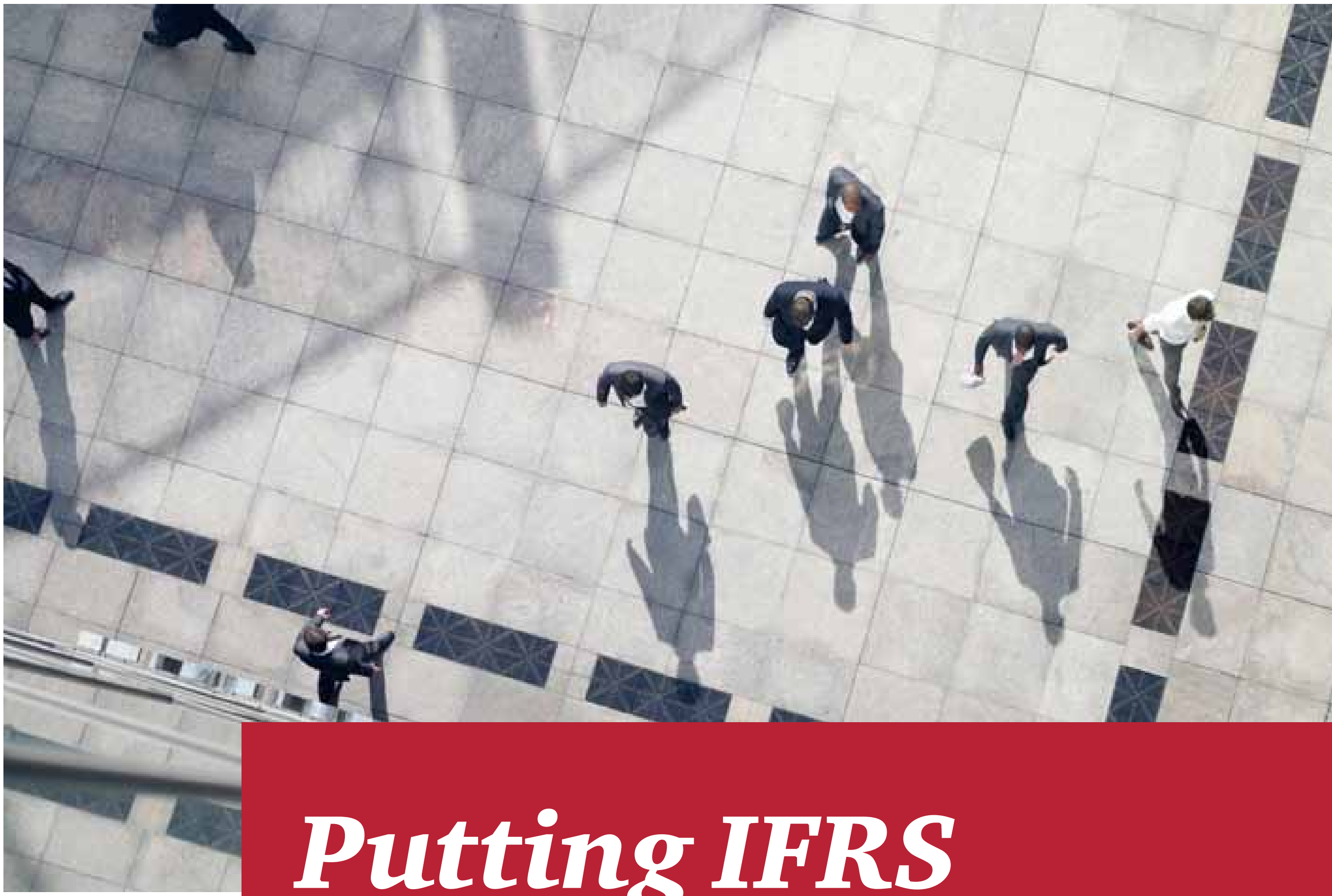

Putting IFRS in Motion

Benchmarking Financial Reporting in Canada's Energy Industry

July 2011

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Foreword

Keeping on track

As early summer has finally arrived in Alberta, we thought it would be a good time to reflect on the past winter, file our tax returns, set budgets for next year, get our excuses ready for our all too short golf season and think about what IFRS really means.

There is no doubt that this conversion caused all of us to read more accounting rules and interpretations than we ever thought possible. At the end of this process, however, it appears that despite obvious changes to depletion calculations and impairment models and some unique circumstances, the overall impact of IFRS has not been as significant for many companies as was originally feared. This is not to say that getting to where we are now has been easy. It is a remarkable achievement for this many companies to make the necessary changes to their accounting policies and keep their day to day accounting on track. As we discuss in the "Next Steps" section at the end of this document, companies need to continue to keep on top of the changes they have made throughout the remainder of this year and thereafter.

Unfortunately, this is not the end of the transition process. The International Accounting Standards Board ("IASB") has recently finalized standards on Joint Arrangements, Consolidation, and related disclosures which will be effective in 2013. Although many oil and gas entities will not experience drastic changes from these new consolidation and joint venture standards there will be specific arrangements which are affected and for which the changes in accounting could be significant. In addition, the IASB has released final amendments to the employee benefit standard effective in 2013 which may have a significant effect on defined benefit pension plan presentation and expense recognition. We encourage entities to begin thinking about these standards well before the mandatory implementation date. We are planning IFRS breakfast sessions in Fall 2011 to further explain the potential implications of these changes.

We'd also like to point out that the IASB is currently working on a number of standards which will spark further debate. In particular there are projects underway that will address the accounting for revenue, leases, and hedge accounting. The IASB and the Financial Accounting Standards Board in the United States ("FASB") recently agreed to re-expose their proposed revenue standard for comment and potential changes to the leasing standard continue to be debated by both boards. We expect that both the leasing and revenue projects will have an impact on the oil & gas industry. An exposure draft on changes to hedge accounting was recently finalized and based on the IASB's tentative decisions we expect that hedge accounting will be simplified and that more commodity hedging strategies could qualify for hedge accounting. We encourage all of you to keep current on these developments and potentially to provide feedback to the IASB as these changes have the potential to impact the oil and gas industry in a more dramatic way than the changes to accounting policies on conversion that we have seen so far.

John Williamson
Partner

Methodology for our study

PwC's Benchmarking Financial Reporting in Canada's Energy Industry study was compiled using the publicly available data filed on SEDAR (System for Electronic Document Analysis and Retrieval) website. The overall population of companies for our survey was based on the list of companies in PwC's Top 100 which was used in our recent 2011 Canadian Annual Energy Survey (please see **www.pwc.com/ca/energyvisions**). From this list we chose 60 public companies to be part of our analysis. We believe this sample of companies will provide excellent information and feedback on your peer group of companies.

We have presented our findings in a summarized format to provide you with a high level understanding of the decisions that were made in our industry. We encourage you to contact us to discuss our findings in more detail and gain additional insight into the details behind this information or to discuss the potential impacts of changes to the standards noted above. Our contact information is listed at the end of this publication.

Impact on results

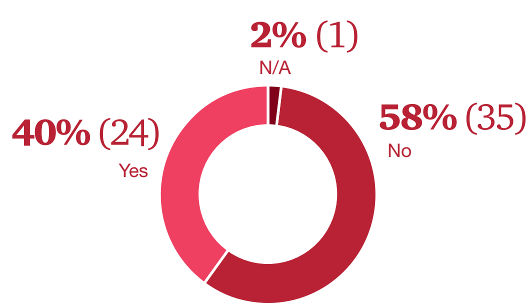
Did the transition to IFRS significantly impact the "cash flows from operating activities" reported by Canadian oil and gas companies?

Cash flow from operating activities, or the similar non-GAAP measure of "funds flow from operations" (typically defined as cash flows from operating activities plus changes in non-cash working capital and decommissioning expenditures) is a key metric for companies in the oil and gas industry.

We compared the cash flows from operating activities reported by the 60 companies in our sample for the three-month period ended March 31, 2010 under IFRS to the amounts previously reported under Canadian GAAP for the identical comparative period.

For 60% of the companies, there was no change in the reported cash flows from operating activities under IFRS as compared to Canadian GAAP. This is not surprising considering that many of the differences between Canadian GAAP and IFRS relate to non-cash items (e.g. impairment, depletion, share-based payments, etc.).

Did the company's cash flow from operating activities change for March 31, 2010?



For those companies that did report changes to cash flow from operating activities, the changes typically related to expensing pre-license costs, capitalizing interest or changes in functional currency.

What about net earnings and earnings per share?

Although the adoption of IFRS did not have a significant impact on the cash flows of most companies in our sample, it did have a material impact on net earnings and earnings per share. All of the companies reviewed reported different net earnings for Q1 2010 and full-year 2010 under IFRS as compared to Canadian GAAP. In many cases the changes were dramatic.

The results under IFRS for the companies in our sample varied considerably; with some companies reporting increases in net earnings under IFRS while others reported decreases. The following differences were the most commonly cited reasons for changes in reported results:

Increases in net earnings

- Lower depletion due to companies adopting an accounting policy of depleting property, plant and equipment ("PP&E") over proved & probable reserves ("2P") under IFRS as compared to only proved reserves ("1P") under Canadian GAAP
- Lower depletion due to impairment charges recorded on transition to IFRS
- Lower accretion expense on decommissioning liabilities due to companies choosing to discount the liability using a risk-free rate under IFRS as compared to the credit-adjusted rate required by Canadian GAAP

Decreases in net earnings

- Impairments of property, plant and equipment recorded in 2010 under IFRS
- Additional expense recorded for lease expiries under IFRS
- Increase in share-based compensation expense as a result of using graded-vesting under IFRS as compared to straight-line expense recognition under Canadian GAAP.

There are also certain changes to the computation of the denominator of EPS that can increase dilution for companies with certain instruments (e.g. debts containing an option for an issuer to settle in shares at maturity).

Given the different requirements of IFRS in certain areas (e.g. impairment, asset dispositions / swaps, share based payments, etc.), Canadian oil and gas companies can expect to continue to see a significant amount of "noise" on the statement of comprehensive income going forward under IFRS.

Accounting for oil and gas assets

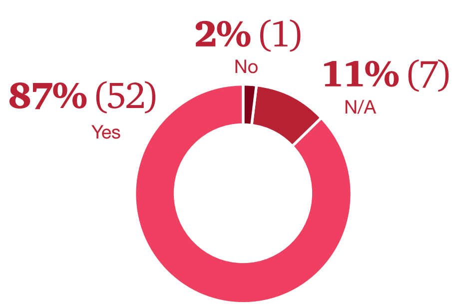
Did Canadian oil and gas companies take advantage of the deemed cost (full cost) exemption to value oil and gas assets on transition to IFRS?

The revision to IFRS 1 that allowed full-cost oil and gas companies to use their previous GAAP net book value as 'deemed cost' on transition to IFRS was seen as a major win for the Canadian oil and gas industry because utilizing the exemption provided a significant time and cost savings alternative to full retrospective adoption of IFRS 6 – Exploration for and evaluation of mineral resources and IAS 16 – Property, plant and equipment.

Therefore, it comes as no surprise that the majority of the Canadian companies in our sample elected to apply the IFRS 1 exemption and carry forward the full cost book value of PP&E as deemed cost at the transition date.

Seven of the companies in our sample were not eligible for the exemption as they did not account for oil and gas assets under full-cost accounting for Canadian GAAP. Therefore, 98% of companies eligible to utilize the deemed cost exemption did so.

Did the company elect to use the deemed cost (full cost) exemption?



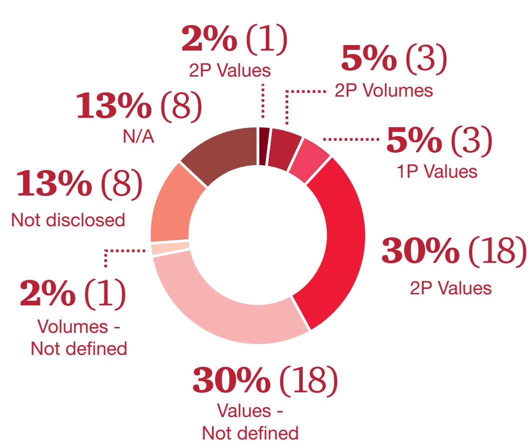
For those companies that did use the deemed cost (full-cost) exemption, on what basis did they allocate the deemed cost of development and production assets?

The IFRS 1 exemption did not prescribe an allocation methodology and provided companies with a policy choice, resulting in the varied responses noted below.

The level of disclosure relating to the IFRS 1 exemption varied significantly amongst the companies in our sample. While a majority (65%) reported using reserve values, rather than volumes, as the basis for their allocation, nearly half of those companies did not explicitly disclose whether they had used 1P or 2P reserve values. For those companies that indicated that the allocation was done based on "reserve volumes" we suspect that they have used 2P reserve values (often discounted at 10%) to align with their policy choices for depletion and impairment requirements of IFRS.

We note that 13% of the companies that elected to utilize the exemption did not explicitly disclose the method used to allocate their deemed cost. We would anticipate that this will be included in the annual IFRS financial statements of most companies.

Method of allocating PP&E



Overall, there was a wide variety of policy choices. Companies had the opportunity to utilize the allocation methodology that made the most sense for their asset base and circumstances. Due to the significant disparity of the ratio of prices (approximately 20:1) and volumetric conversion (6:1) between oil and natural gas as at January 1, 2010, the allocation of deemed cost based on volumes could lead to increased risk of impairments for gas-producing cash generating units ("CGU's").

Is there consistency in how companies have defined "commercial viability and technical feasibility" for purposes of classifying expenditures as exploration and evaluation ("E&E") or PP&E?

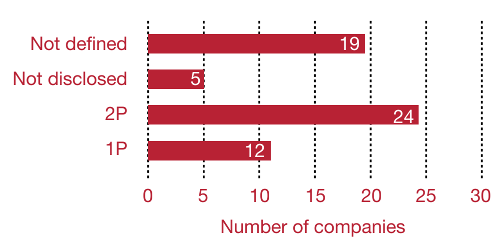
One of the more significant changes on the balance sheets of Canadian oil and gas companies on transition to IFRS is the requirement to present E&E assets separately from development and producing assets within PP&E. IFRS 6 indicates that E&E assets shall be classified as such only until the point at which technical feasibility and commercial viability of extracting a mineral resource is demonstrable.

The standard does not provide an explicit definition of commercial viability or technical feasibility; therefore, determining when to transfer costs from E&E to PP&E is an area of significant management judgment under IFRS.

In reviewing the first quarter interim financial statements of the companies in our sample, we noted significant variability in the manner in which companies chose to define the transition point for E&E assets. Generally, companies referenced the determination of "reserves" as being the point at which commercial viability and technical feasibility was determined, however nearly one third of the companies reviewed did not define whether this meant proved reserves or probable reserves. Of the companies that did provide more clarity, approximately 67% considered commercial viability and technical feasibility to be achieved when probable reserves were determined, while 33% defined these terms as the point at which proved reserves were assigned.

The requirement to separately track and report E&E expenditures is a significant change for Canadian oil and gas companies and will result in changes to accounting processes and controls for most entities.

Definition of commercial viability and technical feasibility



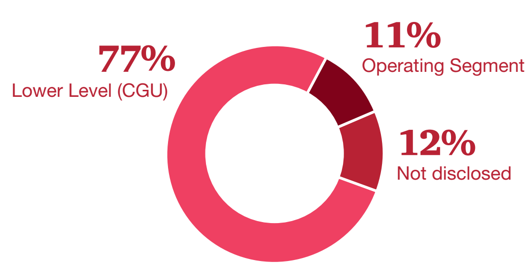
How are companies choosing to aggregate E&E assets for impairment testing?

Most companies have not chosen to amortize E&E assets. Instead, E&E assets are assessed for impairment when facts or circumstances suggest the carrying amount may exceed the recoverable amount of the E&E.

IFRS 6 indicates that E&E assets can be grouped with development and production CGU's when performing impairment tests and provides companies with an accounting policy choice with respect to how E&E assets get allocated to CGU's or groups of CGU's.

Again, the policy choices made and the quality of related disclosures surrounding this key policy choice varied significantly across the sample of companies reviewed. While IFRS 6 does allow companies to group E&E assets with group's of CGU's up to an operating segment level, the majority of companies appear to be allocating E&E assets to specific CGU's (often based on geographical proximity).

E&E aggregation for impairment



Aggregating E&E at the operating segment level for purposes of impairment testing generally reduces the likelihood of impairment while in the E&E phase; but aggregating with specific CGU's often tends to align more closely with how companies operate their business and evaluate the properties. Aggregating E&E at the CGU level also reduces the likelihood of having to record impairment charges when the costs are later transferred to an existing producing CGU.

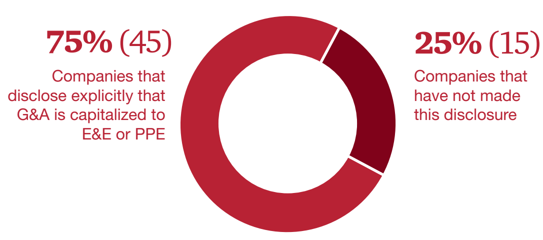
Are companies capitalizing general and administrative ("G&A") costs to E&E or PP&E?

Both IFRS 6 and IAS 16 indicate that costs directly attributable to bringing an asset to the location and condition necessary for its intended use can be capitalized. In many instances, certain overhead costs relating to drilling and development projects are capitalized by the operator or recovered from joint venture partners in accordance with standard industry agreements. Consistent with Canadian GAAP, companies then have to decide whether any additional G&A expenditures qualify for capitalization to E&E or PP&E.

Nearly 75% of the companies in our sample disclosed that they were capitalizing additional G&A costs to E&E or PP&E. For the remaining companies, it is not clear from their disclosures whether or not they are capitalizing any G&A costs in addition to those that may be captured through standard industry agreements.

Based on the information available, there do not appear to have been many significant changes in accounting policies or calculations of capitalized G&A costs upon transition to IFRS.

Does the company capitalize G&A?



Depletion

Did companies deplete oil and gas assets using proved (1P) or proved + probable (2P) reserves under IFRS?

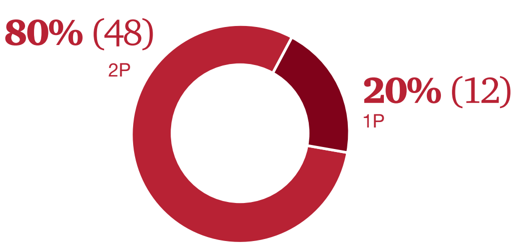
One of the most significant accounting policy choices to be made by Canadian oil and gas companies on transition to IFRS was whether to deplete oil and gas assets based on 1P or 2P reserves.

80% of the companies in our sample have elected to adopt 2P reserves as the basis of depletion under IFRS. We note that only 4 of the 12 companies that have continued to use 1P reserves for depletion produce less than 100,000 barrels of oil equivalent per day. As such, the overwhelming choice among "junior" and "intermediate" oil and gas companies is 2P reserves.

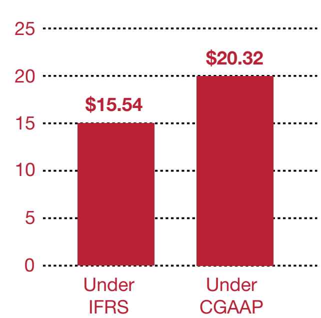
This result is not unexpected given that the change to 2P reserves has a positive result on earnings and aligns with the manner in which many companies manage their business. We note that the average depletion charge per barrel for the three-months ended March 31, 2010 for the companies in our sample decreased by 22% from $20.32 under Canadian GAAP to $15.54 under IFRS.

While the move to 2P depletion has a positive impact on earnings, it will require companies and independent reserve engineers to put more focus on the determination and tracking of future development costs associated with probable reserves. The use of 2P depletion also increases a company's exposure to impairments in future periods as the carrying amount of PP&E will be depleted at a slower pace.

Reserves base for depletion



Average $/BOE – Depletion Expense



Impairment

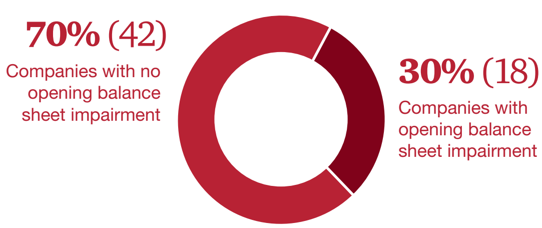
Did the adoption of IFRS result in a significant number of impairment charges for Canadian companies on transition to IFRS?

The requirements for impairment under IFRS differ significantly from those previously applied under Canadian GAAP and increased likelihood of impairment was a risk many companies flagged as a key change on transition to IFRS.

18 of the 60 companies in our sample recorded impairments in their opening IFRS balance sheet as at January 1, 2010. Based on the disclosures provided, the majority of impairments were in relation to gas-producing CGU's. This is not surprising given the commodity price environment that existed at the IFRS transition date. Impairments were also reported by some larger integrated companies with respect to downstream assets (e.g. refineries).

Overall approximately 70% of the companies did not record impairment on transition to IFRS which is not unexpected given a relatively strong oil price environment and the IFRS 1 deemed cost (full cost) exemption afforded companies the ability to allocate their net book value of PP&E to CGU's based on the most advantageous methodology (with the majority using reserve values for the allocation).

Did the company record an impairment January 1, 2010?

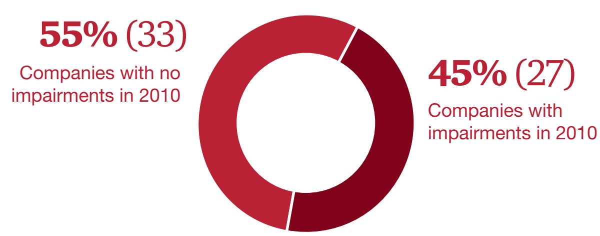


Were there additional impairments reported in 2010?

45% of the companies reviewed reported impairments in fiscal 2010 IFRS statements. The impairments were primarily reported in Q4 2010 and generally related to gas-producing CGU's due to the continual decline in natural gas prices during the year.

For those companies that did report impairment, it is important to remember that write-downs under IFRS are subject to reversal in future periods if facts and circumstances change. This is true for both impairments recorded at the transition date (even if the oil and gas deemed cost exemption was utilized[1]) and for any subsequent impairments.

Did the company record an impairment in 2010?



1. Note that write-downs as a result of applying the fair value as deemed cost transition exemption are not reversible

Discount rates and other impairment disclosures

There are specific disclosure requirements related to asset impairment in IAS 36 – Impairment of Assets ("IAS 36") and IAS 1 – Presentation of Financial Statements ("IAS 1") requires general disclosures related to disclosing sources of estimation uncertainty and the nature of assumptions used in significant estimates. Key assumptions such as discount rates would normally be included in the notes to the financial statements under IFRS.

Based on the first interim financial statements, the nature and quality of disclosures relating to impairment calculations varied considerably.

We found that out of the 60 respondents, 18 reported transition impairments and 27 reported 2010 impairments, with 13 companies recording impairments both at transition and during 2010. While most companies included generic disclosure regarding the impairment requirements under IFRS, more than half of the companies that reported impairments did not disclose the discount rate used in their calculation. Even fewer companies provided information on other key assumptions, including forecast commodity price estimates.

Based on the information available, it appears that fair value less costs to sell ("FVLCTS") was used most often as the basis for determining the recoverable amount when conducting impairment tests under IFRS. This is consistent with expectations given that generally FVLCTS for a Canadian oil and gas company will be higher than value in use ("VIU") due to limitations within IAS 36 relating to price escalation and incorporation of 2P reserve volumes or contingent resources in a VIU calculation.

Our experience is that oil and gas companies would typically calculate FVLCTS based on discounted after-tax cash flows. For those companies that did disclose information on the discount rate applied to the cash flows, the discount rates ranged from 5% to 14%, with 10% being the most common rate applied.

Overall, the lack of detailed disclosures in this area is not really surprising given this is the first set of interim IFRS financial statements and that companies were under significant time constraints preparing for the transition. However, given the significant measurement uncertainty related to impairment calculations and the requirements of the IFRS standards, it is anticipated enhanced disclosure in this area will likely be included in annual IFRS financial statements.

Decommissioning liabilities

Did companies apply a risk-free rate or a credit-adjusted rate when calculating decommissioning liabilities?

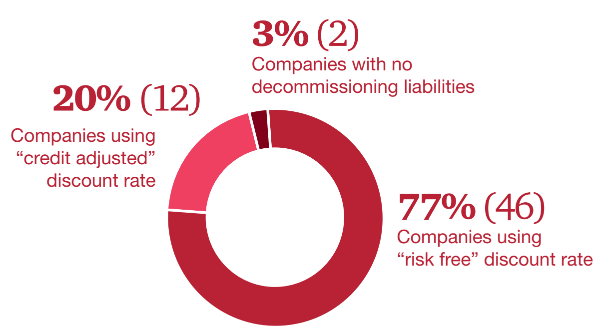
IAS 37 – Provisions, Contingent Liabilities and Contingent Assets ("IAS 37") requires that companies revalue their decommissioning liabilities at the discount rate applicable at each reporting date; however, IAS 37 does not explicitly dictate the discount rate to be applied.

In late 2010 and early 2011, the International Financial Reporting Interpretation Committee ("IFRIC") held meetings and deliberated on the issue of whether IAS 37 was clear as to whether provisions should be discounted at a risk free rate or a credit adjusted rate. Based on these deliberations, the IFRIC chose not to issue any authoritative guidance to clarify the interpretation of IAS 37. Based on the lack of authoritative guidance in this area certain companies have made a policy to continue to use a credit-adjusted rate for discounting decommissioning liabilities (as was the requirement under Canadian GAAP).

Approximately 77% of the companies in our sample chose to measure decommissioning liabilities using a risk-free rate under IFRS which results in a higher liability than previously reported under Canadian GAAP. Of the 12 companies that continued to use a credit adjusted discount rate, 6 were large-cap Canadian companies that also chose to remain with 1P reserves base for depletion.

On average, the companies in our sample experienced a 50% increase in their ARO liability as at January 1, 2010 compared to the amount reported under Canadian GAAP. These changes are primarily due to the use of risk-free rates under IFRS ranging from approximately 3-4% as compared to the credit-adjusted rates which were typically 6-9% under Canadian GAAP.

Did the company use risk-free or credit-adjusted rates for discounting decommissioning liabilities?



Financial statement presentation and disclosure

Have companies chosen to present expenses on the statement of comprehensive income based purely on "nature" or "function" or have they used a hybrid ("mixed") presentation ?

Canadian oil and gas companies overwhelmingly adopted a 'hybrid' presentation rather than following either a 'function' or 'nature' presentation. Most companies preferred to maintain a presentation similar to that used under Canadian GAAP.

Typically, separate expense captions included:

- Operating or production
- Transportation
- Depletion and Depreciation
- General and administrative
- Finance costs (including accretion on decommissioning liabilities)

The use of a hybrid presentation is considered acceptable under IFRS, as long as the information presented is not misleading. However, IAS 1 does require that when expenses are grouped by 'function' (e.g. operating, G&A), that supplemental disclosure be included in the notes to the financial statements to break out significant costs by 'nature'. This supplemental disclosure was not included in most Q1 2011 financial statements, but will be required in the notes to the annual financial statements.

Have "royalties" been presented as a separate line on the statement of comprehensive income or netted against revenue?

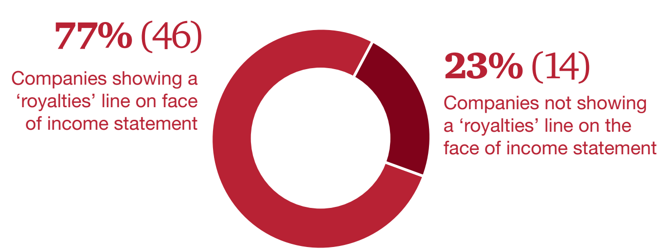
One of the hot topics leading up to the transition to IFRS was the classification of royalties in the statement of comprehensive income. Specifically, the debate focused on whether revenues from the sale of oil and gas should be presented net of royalties on the face of the statements, or whether they could be presented as a separate line item on the statement of comprehensive income.

Based on the guidance in IAS 18 – Revenues, revenues should be presented 'net' of royalties in most instances (e.g. Crown royalties in Canada).

Most Canadian companies in our sample complied with this guidance by defining 'revenue' on the statement of comprehensive income as the amount of sales after deducting royalty interests. However, there was diversity in how this information was presented.

46 of the 60 companies chose to show a 'royalty' line item on the statement of comprehensive income while only 14 companies showed a single line item for revenue, net of royalties. This result is reflective of the views of many Canadian companies that including a royalty line item on the face of the statement of comprehensive income provides relevant information for understanding an entity's performance.

Are royalties presented separately?



Have gains and losses on derivative instruments been shown as a separate line item on the statement of comprehensive income? If so, have they been presented as a single line or two line items (unrealized and realized)?

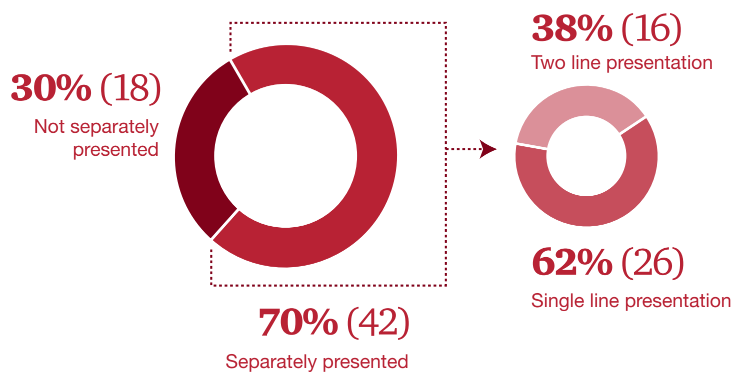
Under Canadian GAAP, many oil and gas companies presented unrealized and realized gains and losses separately on the face of the income statement. "Realized" amounts represented cash payments from settlement of derivative contracts, and "Unrealized" amounts represented the non-cash 'mark-to-market' adjustments required to record the derivatives at fair value on the balance sheet.

The concept of 'unrealized' and 'realized' gains and losses are not defined in IFRS and generally, movements in the fair value of derivatives (which would include both 'realized' and 'unrealized' gains and losses) should be presented on a single line item within the statement of comprehensive income.

Based on the companies included in our sample, we found that approximately 40% of those companies that separately presented gains and losses from derivative contracts on their statement of comprehensive income continued to use a 2-line approach (realized and unrealized) under IFRS.

For the 26 companies that did change to a single-line presentation, we note that the non-cash amount is separately identified in the statement of cash flows (as an add-back in to cash flows from operating activities) and that in some instances, the companies provided a detailed break-down of the total movement into 'realized' and 'unrealized' components within the notes to the financial statements.

Presentation of gains/losses on derivatives



Have companies presented a single statement of comprehensive income or two separate statements?

Canadian companies are required to present a statement of comprehensive income. Currently, under IFRS, there is a choice as to whether companies present all income and expenses within a single statement of comprehensive income, or in two statements: a statement displaying components of net income, and a second statement beginning with net income and displaying components of other comprehensive income.

The majority of the companies in our sample opted to present a single statement. This was expected given that many Canadian companies did not report any differences between net income and comprehensive income.

For those companies that presented two statements, we found that the companies had also previously presented two statements under Canadian GAAP.

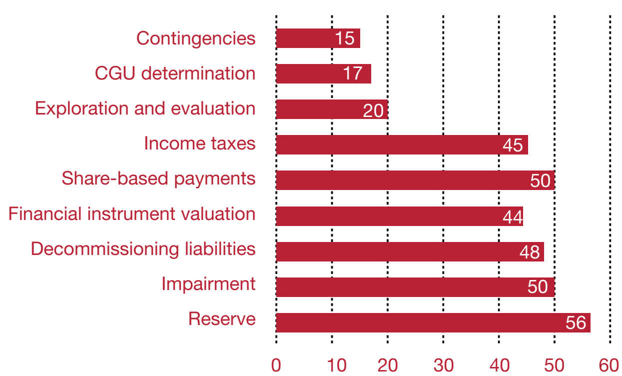
Statement of comprehensive income

What key accounting estimates and judgments were disclosed?

IAS 1 requires that companies disclose the sources of estimation uncertainty for those items that have a significant risk of resulting in a material adjustment to the carrying amount of assets and liabilities within the next fiscal year. While the concept of measurement uncertainty existed under Canadian GAAP, the disclosure requirements under IFRS are more similar in nature to the "Critical Accounting Estimates" section of the Management Discussion & Analysis for Canadian companies.

As expected, substantially all companies surveyed included oil and gas specific items as sources of measurement uncertainty including reserves, impairment and decommissioning obligations. Many of the companies in our sample also included commentary regarding estimates surrounding deferred income taxes, share-based payments and the valuation of derivatives. These are also common within the oil and gas industry.

Key estimates and judgements



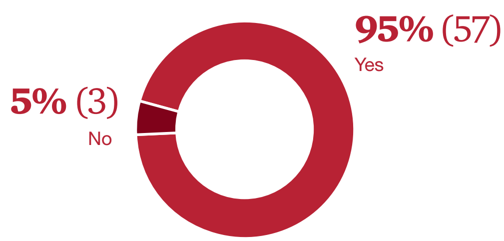
Other areas of estimate or judgment that were included in a small number of companies' financial statements included business combinations, valuation of convertible debentures and the calculation of revenue and operating expense accruals for joint venture activities.

Only a limited number of the companies included reference to CGU identification or the transition from E&E to PP&E in their disclosures. In the case of CGU determination this may be because for some companies CGU identification requires significant judgement and for others the determination is more clear-cut. Similarly, the quantum of E&E transfers may be greater for some companies than others.

Overall, we found that there was quite a bit of variability in the nature and quality of the disclosures around key estimates. While a number of companies did include more in-depth discussion to meet the requirements under IFRS; a number of companies did not provide any additional information as compared to their previous Canadian GAAP measurement uncertainty disclosures.

Did companies include a PP&E continuity note in their interim financial statements?

Was a PP&E continuity note included in Q1 financial statements?



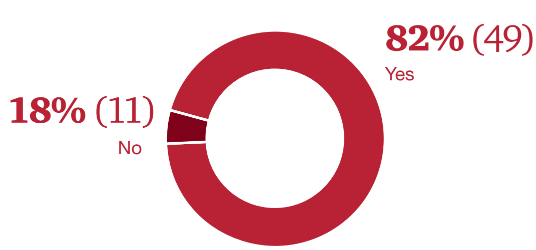
Did companies include an E&E continuity note in their interim financial statements?

Under IFRS, companies are required to provide disclosure summarizing the movement in PP&E balances (both cost and accumulated depreciation). Similar disclosures are recommended for changes in E&E balances.

While it can be argued that these detailed disclosures are not explicitly required for interim financial statements under IFRS unless such information is considered material to understanding the results for the period; we found that substantially all of the companies in our sample included a PP&E continuity note in their Q1 financial statements.

The majority of companies included an E&E continuity schedule as well. Of the 11 companies that did not present an E&E schedule, many did not actually have a material E&E balance on their balance sheet.

Was an E&E note included in Q1 financial statements?



Was key management personnel compensation disclosed in the interim financial statements?

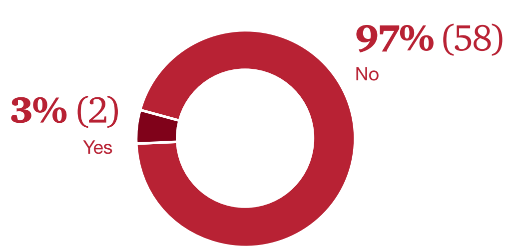
Under Canadian GAAP management were considered to be related parties. However, management compensation arrangements were outside of the scope of the related party disclosure requirements.

On the other hand, IAS 24 – Related Party Disclosures ("IAS 24") specifically includes key management personnel compensation within the scope of related party disclosures and requires companies to disclose the following totals for such individuals:

- short term employee benefits
- post-employment benefits
- other long-term benefits
- share-based payments

Almost all of the companies in our sample did not include this disclosure in their Q1 2011 interim financial statements as key management personnel compensation is generally considered an annual disclosure requirement.

Was key management personnel compensation disclosed in Q1 financial statements?



Companies will need to consider which individuals to identify as 'key management personnel'. Generally, under IFRS we have seen key management personnel defined as including directors and key executives. Companies will need to ensure that their systems are capable of tracking the required information for annual reporting.

What was the impact of IFRS on the amount of disclosure and length of financial statements?

In the period leading up to the transition to IFRS, there was almost unanimous agreement that IFRS would mean more disclosure and longer financial statements. The real question was "how many more pages and disclosures"? Would the volume of information double, or even triple?

A high-level look at the first interim reports issued by the Canadian companies in our sample for Q1 2011 confirmed that the volume of disclosures increased. On average, the Q1 2011 interim financial statements reviewed were 35 pages long; a significant increase from an average of 16 for the financial statements issued under Canadian GAAP for the same period a year earlier.

The Q1 2011 financial statements included an opening balance sheet together with a number of reconciliations from Canadian GAAP. We expect that companies may choose to cut down disclosure in Q2 and Q3 of 2011 by excluding the opening reconciliations. The minimum requirements for the second and third quarter compared to the first quarter can be seen in the table below:

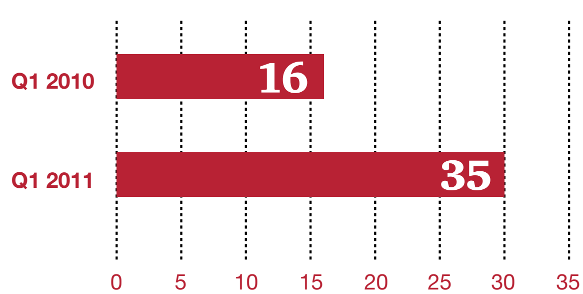
Companies may also choose to exclude certain annual policy disclosures in their second and third quarter financial statements. More details on options available for Q2 and Q3 can be found in our "First-Time Interim Reporting Under IFRS: Questions and Answers" publication (available upon request).

GAAP-IFRS Reconciliation Requirements for 2011 FRS Interim Financial Statements (IFRS 1.32(a) and (b))

	First quarter	Second quarter	Third quarter
Equity	March 31, 2010 January 1, 2010* December 31, 2010*	June 30, 2010	September 30, 2010
Comprehensive income	Three months ended March 31, 2010 Year ended December 31, 2010*	Three and six months ended June 30, 2010	Three and nine months ended September 30, 2010

* Not required if first interim report cross-references to another published document that includes these reconciliations (IFRS 1.32(b)). See "Including IFRS transition information in other published documents"

Average number of pages in Q1 financial statement



Next steps

IFRS was a very interesting and pervasive change management project. The results of this benchmarking study supports the magnitude of these changes on the first IFRS interim reporting period and highlights some interesting issues and challenges for oil and gas companies. Preparing these first IFRS financial statements along with all the other business responsibilities has put an additional burden on many financial executives. Over the next 60 days company's finance teams should reflect on what worked – and what did not work. Based on our experience there are a number of issues that companies should be focussing on:

Firstly, many companies relied on technical consultants to assist with the complexity of researching and evaluating IFRS and its impact on their accounting policies. After Q1-2011 these resources may be redeployed back into other areas of the company, or worse may leave the company altogether. Ensuring that you have access to IFRS technical experts will be key for the first annual reporting period (e.g. year end disclosures may be more robust than this interim reporting). As we noted in the foreword, there are already new IFRS pronouncements requiring analysis. We recommend that companies seek out IFRS learning and education programs for finance and accounting executives and build the need for this learning and education into resource plans to ensure these professionals have the opportunity to get this training. PwC has numerous IFRS subject matter experts that can help with guidance and interpretation of these complex standards. PwC is also planning a Fall IFRS breakfast session series to help companies continue the transition process and complete the first IFRS year end.

Secondly, reporting deadlines were extended for the first reporting period and many companies took advantage of this– no such extension is available for subsequent quarters. Many of the companies that elected not to take the extension and met the normal reporting deadline did so with external consultants and professionals. Again, these resources may no longer be available for the next interim periods or year end. Companies should perform a review of two key business functions which require logistical precision and coordination: the financial reporting period-end process; and the reserves process. Companies should look at ways to remove financial close process bottlenecks that may have been created as part of IFRS transition, enhance the accruals process, and strive to provide more time for management, external auditors and audit committees to review the financial statements. These stakeholders and users of financial statements need your assistance. With respect to the reserves process, companies need to determine if the reserve basis chosen for accounting will require additional coordination, data collection and analysis prior to release to the external reservoir engineers for the year end reserve report (e.g. 2P reserves and future development cost capital budgets, properties moving from E&E to development, etc.). Early coordination of this process will be key to ensuring year end financial statements are prepared efficiently and effectively as many critical calculations are based on the final reserves report.

Finally, the rapid change to accounting policies has often resulted in significant changes to the company's chart of accounts, reporting hierarchies, and other financial data. Managing the accounting policy changes was generally given priority by accounting departments, and there was little time to make the necessary changes to automate processes and to accommodate changes to internal management reporting. Many of the IT system changes that did happen were accomplished using end-user computing tools and/or spreadsheet solutions rather than the functionalities embedded in the company's ERP system. Some ERP systems were not ready to handle these changes by the first interim reporting period. Maintaining these spreadsheets is not only time consuming, but may increase the financial reporting risk for an organization if ongoing reliance is being placed on them. For example, automating the depletion and depreciation calculations might not only save time and resources, but could also enhance the efficiency of the close process. Companies should compile a detailed inventory of all new critical financial reporting spreadsheets and review this list in the context of determining which ones could be integrated into the ERP system. For the remaining essential spreadsheets management should perform an objective review for completeness and validity on the data and the calculations within those spreadsheets. IFRS policy decisions have impacts on internal management reporting. Management reporting requires accounting and finance departments to provide meaningful information to support the key decision makers of the business. Doing a post-mortem IFRS review with the users of management reporting ensures alignment.

PwC believes that performing a "Summer Financial Reporting Health Check" prior to year end makes good business sense to ensure all impacts to people, process and systems are properly managed in the financial reporting of the company. Talk to any of our IFRS professionals to see how we can help.

David Whiteley
Associate Partner

Appendix 1
List of 60 companies with filings on SEDAR

Advantage Oil & Gas
Anderson Energy
Angle Energy Inc
ARC Resources
Artek
Bankers Petroleum Ltd
Baytex Energy
Bellatrix Exploration
Birchcliff Energy
Blackpearl Resources Inc.
Bonavista
C&C Energia Ltd
Calvalley Petroleum
Canadian Natural Resources
Cenovus Energy
Cequence Energy
Chinook Energy Inc
Cinch Energy Corp
Connacher Oil and Gas
Crescent Point
Crew Energy
Daylight Energy
Encana
Enerplus Corporation
Equal Energy Ltd
Exall Energy
FairBorne
Galleon
Husky
Insignia Energy
Legacy Oil+Gas
MEG Energy
Nexen
Nuvista
OPTI Canada
Orion Oil & Gas
Pace Oil & Gas Ltd
Pacific Rubiales Energy Corp.
Pan Orient Energy
Paramount Resources Ltd
Pengrowth Energy Corp.
Penn West Petro
Perpetual Energy
Petrobakken Energy
Petrominerals Ltd
Peyto Exploration
Progress Energy Resources Corp
Rock Energy Inc.
Sonde Resources
Suncor
Talisman
TransGlobe Energy
Trilogy Energy
Twin Butte Energy
Vermilion Energy
Vero Energy Inc.
WestFire Energy
Whitecap
Winstar
Zargon Oil & Gas

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