Updated COGEH Highlights

SPEE
SOCIETY OF PETROLEUM EVALUATION ENGINEERS

October 2019

Agenda

- Introduction – History, Feedback, Goals, and Format
- New and Updated Content - 2018
- New and Updated Content - 2019

History of COGEH

1998 – Identified the need

June 2002 – Volume 1 published

- Reserves Definitions and Evaluation Practices and Procedures
- September 2003 – NI 51-101
- Standards of Disclosure for Oil and Gas Activities (Replacing National Policy No. 2-B)

2005 – Volume 2 published

- Detailed Guidelines for Estimation and Classification of Oil and Gas Resources and Reserves
- September 2007 – Volume 1 Second Edition published

September 2007 – Volume 3 published

- Detailed Guidelines for Estimation and Classification of Coal Bed Methane (CBM) Reserves and Resources
- Reserves Recognition for International Properties
- Detailed Guidelines for Estimation and Classification of Bitumen and Steam Assisted Gravity Drainage (SAGD) Reserves and Resources (Updated October 2013)

June 2014 – Resources Other Than Reserves (ROTR) published

  - Addendum to Volume 2

September 2018 – Consolidated Volume published (including all volumes and ROTR discussed above)

October 2019 – Select portions updated. Red lined version available

Industry Feedback and Goals

Industry Feedback

- Duplication and inconsistency between volumes
- Information out of date
- Create a digital document
- Consolidate the documents
- Alignment of definitions of reserves, resources and product types with NI 51-101
- Additional guidance on operating costs
- Clarity on the inclusion of Abandonment and Reclamation costs
- Clarity on Type Curve creation

Goals

- COGEH is to be a guidance document of industry best practices
- Combine existing documents into a single consolidated document
- Use hyperlinks where possible when referring to regulations and/or examples
- Create an "Evergreen" document
- Digitize and update distribution of the materials
- Remove any redundant material

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Format

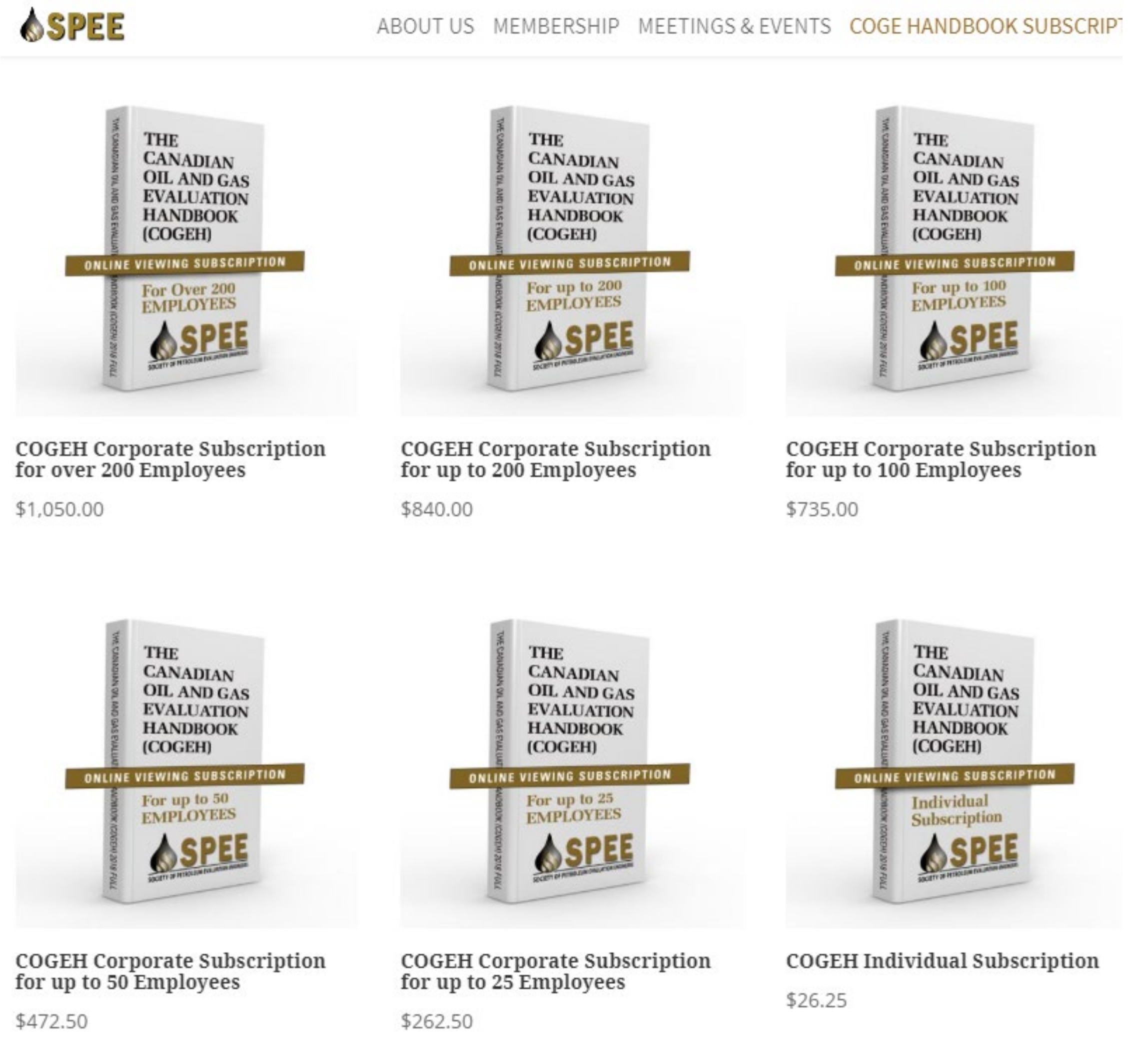
PDF or Subscription

Available as PDF or online subscription

With the subscription:

- Allows for easy searches of the materials for topics of interest.
- Allows SPEE Calgary to keep it “evergreen” and users do not need to purchase updates as that will be included in the subscription.
- Using hyperlinks for some materials allows the information to be up to date.

Subscription Options



Agenda

Introduction – History, Feedback, Goals, and Format

New and Updated Content - 2018

New and Updated Content - 2019

Summary

Changes that will likely require changes to year end 2018 evaluations

- Undeveloped Reserve Bookings and Timing – clarified that for on going development of resource developments, can include up to 5 years of drilling in the proved case and 10 years in the probable undeveloped case, if additional conditions are satisfied
- Guidance on Costs
  - Non active area operating costs – recommendation to include costs within active area. To be explicit about other properties excluded from the evaluation
  - Maintenance capital – to include all maintenance capital

Changes that may not require changes to year end 2018 evaluations (but should still be reviewed in detail)

- Type Curve Generation – additional best practice materials. Note that a lot of this material is consistent with SPEE Monograph 3 and 4.
- Product Types – simplified product types, however, reporting requirements for NI 51-101 or reporting jurisdiction (this is unlikely to change our evaluations unless NI 51-101 changes product types)
- Statistical Methods – additional material but not prescriptive
- Social and Environmental Considerations - additional material but overall similar to Chance of Development factors previously included
- For conventional evaluations, updated undeveloped reserve bookings and timing not substantially changed
- Reconciliation categories – clarified A&D
- Infrastructure and markets – for expansions, market required to book reserves

Undeveloped Reserves (1/2)

Key Wording

- For large projects, where significant capital is required for field development or infrastructure construction, significant capital expenditures should commence within three years for assignment of Proved Undeveloped Reserves. For the assignment of Probable Undeveloped Reserves, significant capital spending should commence within five years. If significant capital expenditures do not occur within these times, the associated oil and gas quantities should be classified as Contingent Resources.
- For new or expansions to existing facilities to be built by the producer, detailed capital cost estimates and further compelling documentation from the Company is required for the facility to be included in the reserve categories. For facilities to be built by third parties, an executed contract with the third party is required for the facility committed capacity to be included in the reserve categories.
- **Highlights – when booking a company operated facility expansion, detailed capital cost estimates and firm intent from the board required to include it. If the facility is being built by a third party, a signed agreement is required.**

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Undeveloped Reserves. For the assignment of Probable Undeveloped Reserves, significant capital spending should commence within five years. If significant capital expenditures do not occur within these times, the associated oil and gas quantities should be classified as Contingent Resources.

For new or expansions to existing facilities to be built by the producer, detailed capital cost estimates and further compelling documentation from the Company is required for the facility to be included in the reserve categories. For facilities to be built by third parties, an executed contract with the third party is required for the facility committed capacity to be included in the reserve categories.

Each large project will be unique in terms of the time required to develop the associated proved or Probable Undeveloped Reserves. Large processing facilities generally have a design life of 20 to 30 years, although these can typically be extended with maintenance capital, replacement of major components, and facility upgrading.

The following is a discussion of the guidance related to Reserves evaluations for certain common situations:

- **Ongoing Resource Play Development:** For Resource plays where drilling programs have been underway for a few years and are expected to continue for some time due to a large inventory of locations that qualify for assignment as Reserves, it is reasonable to have Proved Undeveloped Reserves assigned for five years of development drilling and Probable Undeveloped Reserves extending out for ten years of development drilling.
- **Gas Processing Facilities:** When construction is underway of a large gas processing facility in which the Reserve owner has committed capacity and is forecasted to be completed within two years to develop a large Resource, it is reasonable to schedule drilling wells for up to five years from the start-up of the facilities in the Proved Undeveloped Reserves category. In the Proved plus Probable Undeveloped Reserves category drilling is limited to ten years from the effective date of the report.
- **In-Situ Projects:** Projects involving In-Situ recovery processes typically require a large upfront capital expenditure for the steam generators, related infrastructure and the first phase of well-pairs. Within the project area defined in the field development plan, there may be areas where Reserves are categorized as proved or probable undeveloped or classified as Contingent Resources depending on the well density used to define the accumulation or the geological characteristics of the accumulation. It is acceptable to schedule drilling well-pairs for the time frame required to recover the assigned Reserves. Drilling should not extend beyond the design life of the facility unless adequate maintenance capital is scheduled in the evaluation, to a maximum of 50 years.
- **Bitumen Mining Projects:** Projects involving bitumen mining typically require a large upfront capital expenditure for infrastructure and processing facilities. Within the project area defined in the field development plan, there may be areas where Reserves are categorized as proved or probable undeveloped or classified as Contingent Resources depending on the well density used to define the accumulation or the geological characteristics of the accumulation. It is acceptable to schedule mining for the time frame required to recover the assigned Reserves. Mining should not extend beyond the design life of the facility unless adequate maintenance capital is scheduled in the evaluation, to a maximum of 50 years.

Undeveloped Reserves (2/2)

Guidance

- For resource plays only (Montney, Duvernay, etc.), 5 years of undeveloped locations can be booked in the 1P and 10 years in the 2P case
  - When a facility is under construction, can book 5 years from the onstream date to a maximum timeframe of 7 years from the effective date
  - The facility on stream date does not effect 2P bookings – the timeframe is a maximum of 10 years from the effective date
- Note that only the expanded facility capacity can be booked from the on stream date
  - Ex. A company has a 200 MMCF/D facility that they are expanding to 300 MMCF/D that is under construction and will be on stream one year after the effective date. Proved undeveloped reserves that fill the original 200 MMCF/D facility can only be booked for 5 years. In addition, the 100 MMCF/D can be booked from year 2 through 6 after the effective date. As a result, in year six, undeveloped reserves can be booked to fill 100 MMCF/D of capacity.

COGEH – As Written

The following is a discussion of the guidance related to Reserves evaluations for certain common situations:

- **Ongoing Resource Play Development:** For Resource plays where drilling programs have been underway for a few years and are expected to continue for some time due to a large inventory of locations that qualify for assignment as Reserves, it is reasonable to have Proved Undeveloped Reserves assigned for five years of development drilling and Probable Undeveloped Reserves extending out for ten years of development drilling.
- **Gas Processing Facilities:** When construction is underway of a large gas processing facility in which the Reserve owner has committed capacity and is forecasted to be completed within two years to develop a large Resource, it is reasonable to schedule drilling wells for up to five years from the start-up of the facilities in the Proved Undeveloped Reserves category. In the Proved plus Probable Undeveloped Reserves category drilling is limited to ten years from the effective date of the report.

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Operating Costs

Key Wording

- Inactive assets and their related costs should be included in the evaluation to properly represent the asset(s) being evaluated. It is recommended that inactive costs be forecast separately from active asset costs at the property or corporate level, so economic production entities are not unduly burdened. When included in this fashion an appropriate method can be employed to retire these costs over time.
- **Highlights – include a one line entity for non active area operating costs. Recommended that inactive costs forecast separately to not unduly burden active entities.**
- **To clearly state which properties are included vs excluded.**

COGEH – As Written

3.6.2 COSTS ASSOCIATED WITH ACTIVE AND INACTIVE ASSETS

The evaluator, when analyzing historical operating expense data to establish operating costs for an evaluation, should carefully consider those costs associated with active and inactive entities within a property.

Active entity and area costs represent those costs that directly burden producing wells, including the associated gathering and processing facilities and related disposal and injection facilities.

Inactive entity and area costs represent those costs associated with non-Resource bearing lands or inactive wells in an area. In general, in-active entity costs include:

- mineral lease rentals;
- shut-in, suspended and capped well operating costs;
- shut-in operating and gathering systems and related processing facilities; and
- future ADR liabilities.

Canadian Oil and Gas Evaluation Handbook – Consolidated 3rd Edition – (Online) 206 | P a g e

They are often components included with active assets in an area or appear as inactive areas within a company's portfolio.

Inactive assets and their related costs should be included in the evaluation to properly represent the asset(s) being evaluated. It is recommended that inactive costs be forecast separately from active asset costs at the property or corporate level, so economic production entities are not unduly burdened. When included in this fashion an appropriate method can be employed to retire these costs over time.

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Maintenance Costs

Key Wording

- Operating cost statements may not include the ongoing maintenance costs required to maintain area facilities and gathering systems. These costs may occur periodically, once every few years, and therefore will not always appear in typical lease operating statements provided to determine certain economic parameters. Alternatively, these costs may be capitalized. Including maintenance costs in an asset evaluation is critical, as without required maintenance, most properties will not be able to maintain operations for the extended periods, which production is forecast to occur.
- Forecasts of required maintenance costs, expensed or capitalized, must be obtained from the company and included in an evaluation. These maintenance costs are mostly fixed and will continue throughout the life of facilities until production from the region they service approaches its twilight years. In later years, maintenance costs would be managed to maintain production at economic levels until the field is no longer economic to produce.
- In some instances, facilities may be completely shut-in and area production diverted to alternative facilities. This action; however, requires additional capital investment.
- **Highlights – discuss with companies that the new version of COGEH has strict wording that maintenance capital is to be included in the evaluation. Request maintenance capital for the past two years and a future forecast from the company**

COGEH – As Written

3.6.1.3 MAINTENANCE COSTS

Operating cost statements may not include the ongoing maintenance costs required to maintain area facilities and gathering systems. These costs may occur periodically, once every few years, and therefore will not always appear in typical lease operating statements provided to determine certain economic parameters. Alternatively, these costs may be capitalized. Including maintenance costs in an asset evaluation is critical, as without required maintenance, most properties will not be able to maintain operations for the extended periods, which production is forecast to occur.

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In some instances, facilities may be completely shut-in and area production diverted to alternative facilities. This action; however, requires additional capital investment.

Product Types

Key Wording

- Recommended product types simpler than previous list
- However, NI 51-101 product types unchanged year over year and as a result expect similar disclosure

COGEH – As Written

1.2.1 PRODUCT TYPES

Reporting of evaluation results is generally in terms of product type rather than Resource Type, which may vary, depending on the requirements of the organization for which a report is prepared. COGEH does not prescribe product types for reporting because regulatory and other agencies may define the product types they require for reporting and different agencies may define different product types. Reference should be made to the specifications of those agencies when preparing a report. See, for instance:

- CSA National Instrument 51-101 Part 1.1 Definitions, Product Type, for a list of the Product Types required in reports prepared for NI 51-101. NI 51-101 Effective July 1, 2015
- SEC S-K § 229.1202 (Item 1202). Disclosure of Reserves.
- Financial Accounting Standards Board (FASB) Accounting Standards Update 2010-03. Extractive Industries – Oil and Gas (Topic 932).

Evaluators should ensure they use the product types required for an evaluation, and users of evaluation reports should ensure they understand what these represent. However, when the product types required for a report are not specified, it is recommended evaluators use the following (the definitions of which can be found in the Glossary):

Oil:	Light, Medium
	Heavy
	Bitumen
	Synthetic Crude Oil
Natural Gas:	Associated
	Non-Associated
	Coalbed Methane
By-Products:	Ethane
	Propane
	Butanes
	Pentanes Plus (Condensate)
Non-Hydrocarbons:	Sulphur
	Helium

Type Curves

Key Wording

- Additional detail on best practices for type curve generation. Most recommendations not prescriptive
- In general agreement with material within SPEE Monograph 3 and 4
- Detailed examples on data normalization
- Recommended minimum terminal decline rate: "Enforcing a terminal decline rate in late time is mandatory for wells with high hyperbolic rates"
- "The terminal decline rate is controlled by formation parameters, well completion (fracture spacing and half-length), and development density, but is often in the range of 5 to 15 percent per year. The value should be determined based on experience and/or analogs."
- "Theory states that early time transient linear flow hyperbolic behaviour should be b = 2.0. Based on actual production results observed in HMSF wells within Western Canada, hyperbolic behaviour of 2.0 or greater is rare and generally only for short periods of time. The Canadian Oil and Gas Evaluation Handbook (COGEH) recommends that segment 1 hyperbolic factors of b > 1.5 should only be used for limited periods of time (months) and there are very few examples where a b of greater than 2 is required. Transition to the second segment is typically estimated based on flow time, reservoir characteristics, and current decline rate. Based on observing actual wells, the stabilized b, typically seen in segment 2, is typically between 0.8 and 1.3, depending on reservoir and completion conditions."

COGEH – Table of Contents

Social and Environmental Considerations

Key Wording

- Consideration of social and environment contingencies should already have been considered (reserves are assumed to have a chance of commerciality of 100%). However, additional guidance provided.

COGEH – As Written

Reserves have been determined according to the standards of the COGEH, including the condition for commerciality noted above.

There is no standard process for assessing social and environmental contingencies, but the following steps are recommended:

(a) Identify any relevant social and environmental contingencies.
(b) Estimate the probability that relevant socio-environmental issues will be resolved and maintained over the life cycle of the project. This resolution will depend on the specifics of an asset or project and the legal, regulatory and social environment in which it is proposed to be carried out. Although qualitative and subjective, the assumed resolution should be based as much as possible on a documented analysis. In many cases, there will be a history of similar project developments that can be used as analogues.
(c) Consider the status of the efforts being made to resolve socio-environmental issues. The level of effort and engagement required will depend on the project.
(d) Provide appropriate explanation in a report.

1.4.7.2.1.6 POLITICAL CONTINGENCY

Contingent Resources refers to political contingences, and, although this may not be a consideration, they can have a significant influence on the ability to proceed with a project. It is not often clear where the boundary between social and political issues lies. From the point of view of classification, the issues can be an action by a controlling organization that may influence, impede, or facilitate the ability to proceed with a project. The controlling organization can range from a government to a guerrilla activity, and an action may also include legislation, expropriation, or armed conflict, etc.

Political factors may sometimes be considered as force majeure situations. An example of this was a reclassification of Reserves to Contingent Resources as the result of an armed conflict in Libya in 2011.

Infrastructure and Markets

Key Wording

- Guidance reasonably unchanged
- However, given the recent oil and gas transportation bottlenecks observed within the WCSB, a clear plan is required for reserves to be assigned. It cannot be assumed that there will be a market especially when large expansions are expected.
- "An evaluator may assign Reserves if a market exists or is likely to develop for the sale of production from a property. In circumstances where a market is identified but is not currently available, the evaluator must assess the level of confidence in the likelihood that a market will be secured when classifying oil and gas Reserves."

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1.4.7.2.1.7 INFRASTRUCTURE AND MARKETS

There must be identifiable transportation infrastructure and a market to move and sell the production from an oil and gas property for an evaluator to assign Reserves. For Proved Reserves, access to infrastructure and markets must be secured or highly likely to be secured within a short time. For Probable Reserves, access to infrastructure and markets must also be highly likely but within a slightly longer time. Considerations related to the timing of production and development is presented in the following section.

Market options can span from the highly transparent spot or short-term markets for natural gas and crude oil sales now common in North America and the United Kingdom (and governed by industry-standard precedents) to long-term, single purchaser markets with very specific and unique terms and documentation.

An evaluator may assign Reserves if a market exists or is likely to develop for the sale of production from a property. In circumstances where a market is identified but is not currently available, the evaluator must assess the level of confidence in the likelihood that a market will be secured when classifying oil and gas Reserves.

If a property owner does not have an ownership interest in existing infrastructure, an evaluator may assign Reserves to that property if the required gathering and/or processing agreements with the infrastructure owners either exist or are likely to be put in place. When classifying oil and gas Reserves, an evaluator should consider:

Canadian Oil and Gas Evaluation Handbook – Consolidated 3rd Edition – (Online) 40 | P a g e

- the level of confidence that applies to various factors, including the likelihood of the required agreements being finalized;
- the capacity availability (existing and/or future);
- the priority of service; and
- agreement terms.

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- Introduction – History, Feedback, Goals, and Format
- New and Updated Content - 2018
- New and Updated Content - 2019

2019 Update

- The following has changed:
  - IFRS 16 guidance
  - ADR requirements
  - Reconciliation changes
  - Minor updates
- The following is likely to be edited in the near term:
  - Guidance on forecast prices – at this time, a draft is being circulated to industry with implementation in April 2020

2019 Changes - ADR

Added Wording

- For reserve reports that are being released in the public domain, all ADR costs within the active assets evaluated should be included.

Changed Section

For annual company reserve reports that are to be released in the public domain, COGEH recommends that at a minimum all ADR costs within active assets should be included in the reserve report. For active assets, costs for both active and inactive entities should be included. As an example, for an active asset evaluated in central Alberta, all active and inactive development costs described below is recommended to be included in the evaluation.

For reserves reports that are not being released in the public domain, the report must clearly describe which ADR costs are included and excluded from the evaluation.

Statements regarding ADR costs should address both active and inactive development including but not limited to:

- producing wells;
- suspended wells;
- service wells;
- gathering systems;
- facilities; and
- surface land development.

2019 Changes - IFRS

Summary

- Effective for financial reporting periods beginning on or after January 1, 2019, companies applying International Financial Reporting Standards (“IFRS”) will adopt IFRS 16 – Leases (“IFRS 16”). The new standard is a fundamental change on how lessees record and measure operating leases, and can materially effect the data in which reserve evaluators receive within the lease operating statements.
- COGEH notes that all costs contained within previous reports need to be included going forward, even with the IFRS changes

Added Section

A contract contains a lease when the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. Some examples of oil and gas contracts for which there may be an underlying lease include: rental agreements for field trucks, compressors, and storage assets; processing facilities; pipelines and other transportation arrangements; some land access rights; and drilling rig service agreements. Whether these arrangements are in scope of IFRS 16 will depend on the specific facts and circumstances and underlying contract terms.

Previously, most leases in the oil and gas industry were classified as operating leases, with lease payments presented in the income statement as operating expenses. IFRS 16 requires companies to create a lease liability and recognize a corresponding right-of-use asset for every identified lease, except for certain short-term or low value leases, calculated as the present value of the future fixed lease payments. This right-of-use asset will be depreciated over the economic life of the contract as depreciation expense. The amount of the lease liability will be impacted by the implicit interest on the lease liability and actual cash payments made. Effectively, the operating expense line item recognized under the previous standard will be bifurcated between depreciation expense and interest expense. The timing of expense recognition will be front-loaded as a result of measuring the present value of the lease liability.

In the statement of cash flows, operating lease payments used to be reflected as an operating activity. Under the new standard, principal payments will be recognized as a financing activity, and interest payments will be recognized as either operating or financing activities depending on the company’s existing accounting policy for presentation of finance costs in the cash flow statement.

2019 Changes - Reconciliations

Summary

- Changed wording back to “Reserves” from “Volumes”. “Reserves” was used in the original COGEH.
- Added wording that “Technical revisions are generally independent of reserves changes associated with capital expenditures.”
- Clarified changes in Reserves category from Probable to Proved

Changed Section Example

4.6.2.4 SPECIAL RESERVES CHANGES

a. **Changes in Reserves Category from Probable to Proved.** For Reserves assigned to an exploration discovery, a drilling extension, infill drilling, or an improved recovery project, that are initially categorized as probable only, they should be categorized as a proved addition, in the same reserves change category, in the year when the Reserves are categorized as Proved. For multi-phased improved recovery projects, the recategorization of phases from probable to proved would result in a proved addition for that phase in the same Reserves change category in the year when the Reserves are reclassified as proved.

Any subsequent changes to the Proved Reserves assignment should be recorded as a technical revision.

In specific cases, where Proved Reserves were not originally assigned for economic or technical reasons, and in subsequent years are categorized as Proved Reserves, the Proved Reserves ~~should~~ may be recorded as a technical revision as a result of new technical information becoming available.

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2019 Changes - Pricing

Potential Changes

- Forecast pricing changes have not been incorporated into the September 2019 update
- A committee met several times during the summer of 2019 and have proposed limits to how much forecast prices can deviate from strip
- The committee is going to welcome industry comments, then will provide guidance in April 2020

Change under consideration

- Forecast prices for major benchmarks do not exceed strip prices by 10, 20 and 30 percent within forecast years 1, 2 and 3, respectively. The change in the range reflects greater uncertainty in strip prices in the long term. COGEH recommends the following as the benchmark prices: WTI oil, Edmonton Light oil, Henry Hub gas and AECO gas
- After forecast year three, real prices of the benchmarks should not be adjusted. Nominal prices should be increased by inflation only as a result. Nominal prices, sometimes called current dollar prices, measure the dollar value of a product at the time it was produced. Real prices are adjusted for general price level changes over time, i.e., inflation or deflation.

Acknowledgements and Questions

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- 2019 update was coordinated by Mike Verney
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