CANADIAN

OIL AND GAS

EVALUATION HANDBOOK

Consolidated Third Edition – (Online)

September 2019

Reserves Definitions

and

Evaluation Practices and Procedures

Prepared by

Society of Petroleum Evaluation Engineers
(Calgary Chapter)

Furthermore, COGEH provides a standard other groups such as governments, transmission companies, energy purchasers and financial users, just to name a few, can use in their business models.

Regulatory or legislative rules or guidelines, including specific requirements for reporting in jurisdictions outside of Canada, may permit or require deviation from the evaluation guidelines set out in the Handbook. In all other instances, SPEE Calgary Chapter expects that oil and gas Reserve and Resources evaluations for public disclosure in Canada will adhere to standards and guidelines in COGEH. Further, it is emphasized the Handbook should be used and considered by evaluators in its entirety and it is neither appropriate nor acceptable for evaluators to use or exclude portions of the guidelines on a selective basis unless they can provide valid, technically compelling reasons for doing so.

If evaluators deviate from the Handbook in preparing a Reserves and Resources evaluation intended for public disclosure in Canada, it is further expected they will disclose this fact in writing within their evaluation report, together with an explanation for the deviation.

I trust the COGEH will continue to be a useful standard for practicing evaluators and other parties. It is my hope that it will continue to improve consistency to the evaluation of oil and gas Reserves and Resources across the industry.

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Chairman 2018 COGEH Update Committee, SPEE (Calgary Chapter)

Note that there have been modifications to the original 2018 version. Changes were released in December 2018 and September 2019. Discussion of the major changes have been posted to the SPEE Canada website and have been incorporated into this document.

Acknowledgements

These guidelines were prepared by numerous committees and sub-committees of the SPEE Calgary Chapter and other industry professionals. This has involved countless volunteer hours of effort on the part of many experienced, dedicated and determined individuals over the last two years. This effort built on the substantial amount of work performed on COGEH Volumes 1 through 3 and the ROTR Guidelines. Without the foundation provided by the prior editions, this undertaking would have been much more difficult. Many hours of discussion and debate were held at the committee and subcommittee level covering a wide range of topics. The overarching goal of this update is to provide a Handbook of the current "best practices" to use in the evaluation of oil and gas Reserves and Resources, within a single manual. The committee members also recognize that as both computing technologies advance and development techniques evolve, there is a need to leave room within the Handbook to allow for future updates.

I would like to thank the oversight committee for their dedication to this project. They are as follows:

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challenge the economics of an enhanced oil recovery (EOR) project, CO_2 has a market opportunity with EOR. As with the evaluation of all EOR projects, the cost of capture, delivery, and injection of the CO_2 must be included as a cost association with EOR production volumes.

3.4.9 OTHER PRODUCTS

Other products such as Helium, Coke, Vanadium, etc. have the potential for creating value and may warrant an evaluation. If they are part of the petroleum, natural gas, or bitumen production stream the same concepts will apply to their evaluation.

3.5 PRODUCT PRICES

The value of oil and gas assets is based on future revenue the asset will produce; therefore, a price forecast is necessary to assign value. Prices of oil and gas, like all commodities, are subject to the economic influences of supply and demand, both regionally and globally. Additionally, concerns about climate change and the dependence of the world economy on fossil fuels adds political factors to oil and gas pricing that can impose economic conditions on the oil and gas industry. Even a cursory review of historical oil and gas pricing demonstrates the commodity price volatility, which the oil and gas industry has always dealt with. Therefore, there is no certainty that forecasted prices will materialize. It is important to note that the price forecast used at a given point in time should be considered reasonable with guidance based on available market intelligence. In a balanced market, with willing sellers and buyers, a price forecast can represent a consensus of buyers and sellers who, through their purchase and sale transactions, establish value in the market place.

Developing a price forecast requires knowledge of the market conditions for each product within the context of local and global supply-demand conditions. The development of the price forecast also needs to account for geo-political issues that may influence commodity prices. Below is a list of companies in the evaluation business that sustain a research group and regularly generate publicly available price forecasts:

- GLJ Petroleum Consultants (403) 266-9500, www.gljpc.com;
- McDaniel & Associates Consultants Ltd. (403) 262-5506, www.mcdan.com; and
- Sproule Associates Limited (403) 294-5500, www.sproule.com.

COGEH may incorporate forecast pricing guidelines in April 2020. A committee met several times over the summer of 2019. The committee will gather comments before released guidelines.

Other evaluation firms also offer their price forecasts on their websites. Reference to the above firms does not imply a preference or bias for their price forecasts.

Market intelligence can be derived from other sources. The New York Mercantile Exchange provides information on the future oil and gas price commitments of commodity buyers and sellers in the financial market. As well, government agencies provide historical information and forecast scenarios:

- New York Mercantile Exchange, Nymex Pricing;
- Organization of the Petroleum Exporting Countries (OPEC) Bulletin, OPEC;
- National Energy Board, NEB Data;
- Alberta Energy Regulator, AER; and
- U.S. Energy Information Administration, EIA.

Common operating costs that may sometimes be classified as variable in relation to the product produced and processed are:

- emulsion and crude oil trucking;
- water disposal;
- emulsion and crude oil treating and chemical costs; and
- third party gas gathering and processing costs.

The evaluator should analyze historical operating expense data, field operations, and long-term production characteristics data to establish the allocation of costs between fixed and variable components. For a cost to be variable in relation to a specific product, the cost must effectively remain constant in relation to that product's production profile over an entity's life.

- Take for example, an oil property where the produced effluent is a combination of oil and water and the produced fluids are trucked. If the water cut is expected to stay constant over the life of the well, the effluent trucking and processing costs can be forecast as variable in relation to oil.
- If the well is expected to produce at the same fluid rate throughout its life, with an increasing water cut, the same monthly cost will be incurred regardless of the actual oil produced. This cost should be modelled as a fixed monthly cost or split between a variable oil and a variable water cost assigned to the forecast water production. In this example, water disposal costs would increase over time as water volumes increase.

Beginning January 1, 2019, International Financial Reporting Standards "IFRS" adopted IFRS 16. The bulletin relates to how lessees account for operating leases and can materially effect the data in which reserve evaluators receive within the lease operating statements. The main change due to IFRS 16 is that income statements will be realigned with current rent expense being replaced with interest and depreciation. Costs that have historically been recognized as operating costs will now be recognized as depreciation and interest expenses for in financial reporting.

Per IFRS, "A lessee measures right-of-use assets similarly to other non-financial assets (such as property, plant and equipment) and lease liabilities similarly to other financial liabilities. As a consequence, a lessee recognises depreciation of the right-of-use asset and interest on the lease liability. The depreciation would usually be on a straight-line basis. In the statement of cash flows, a lessee separates the total amount of cash paid into principal (presented within financing activities) and interest (presented within either operating or financing activities) in accordance with IAS 7."

Per IFRS, "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.".

COGEH recommends that the operating costs that may now be recognised as depreciation and interest expense, continue to be included within the operating cost category in reserve reports. In summary, future capital and operating costs should continue to be included in forecasted expenditures on leased assets associated with oil and gas properties.

As an example, a company pay $1,000 per year to lease a truck. Before implementation of IFRS 16, the $1,000 expense would be an expense within the lease operating statement. After implementation of IFRS 16, the company will incur both depreciation and finance expense and will carry the lease asset on its balance sheet (after year one, within the balance sheet, $9,000 will be noted as a lease asset and as a lease liability). COGEH recommends that the depreciation and finance expenses continue to be included as operating costs within reserve reports.

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.

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.

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.

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.

3.6.3 THIRD PARTY PROCESSING AND OPERATING INCOME

An evaluation should not use third-party processing and operating income to reduce operating costs. However, in facilities where there are significant third-party processing revenues the evaluator may consider allocating some of the facility operating costs towards processing third-party production.

The evaluation and inclusion of third-party processing and operating income needs to recognize the differing risk profile associated with third-party income, over and above the risks associated with Reserves and forecast estimations. The incremental risks include the reduction of income, due to a third-party's ability to divert production to competitive processing facilities or build and operate their own gathering and processing facilities.

3.6.4 ABANDONMENT, DECOMMISSIONING AND RECLAMATION COSTS

ADR costs represent the end of life costs associated with restoring to a standard imposed by applicable government or regulatory authorities, an asset where petroleum exploration, development, production and processing operations have been conducted. These ADR costs should always be considered in the evaluation process and notably can vary greatly for a multitude of reasons including, but not limited to:

- the vintages of entities within an evaluated property;
- the history of operations;
- environmental stewardship of multiple operators over long periods of time; and
- initial well and facility designs.

Further, ADR liabilities, though not quantifiable, may continue to exist long after a company has actually conducted their ADR activities.

Environmental damage associated with oil and gas development has emerged as a material societal concern and ADR costs are subject to increased scrutiny. Each report must clearly describe the ADR costs:

- included in the evaluation; and
- those excluded from the evaluation.

For reserve reports that are being prepared for public Canadian disclosure, all ADR costs within the country evaluated should be included in the reserve report.

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.

Further, an estimate of ADR costs included in an asset evaluation must be properly assessed with reliance on those with the requisite expertise. The source of ADR cost estimates must be identified, and the evaluator must stipulate a disclaimer.

3.6.4.1 ADR COSTS ON EXISTING DEVELOPMENT

Estimating ADR costs on existing development requires detailed knowledge of the property, the history of each well and facility, and may require site visits. The analysis and estimation of ADR costs is company's responsibility and resides in the context of their ADR obligation reporting. Without detailed scrutiny of existing development in its entirety, the ADR cost estimates presented in an evaluation may be misleading or imply a level of due diligence evaluators do not typically undertake.