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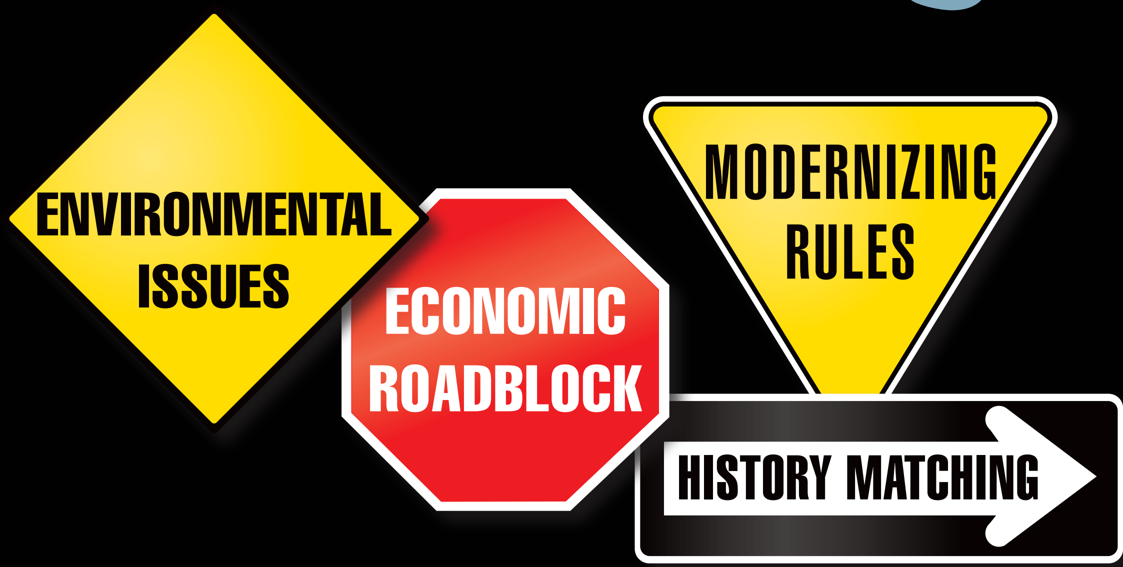
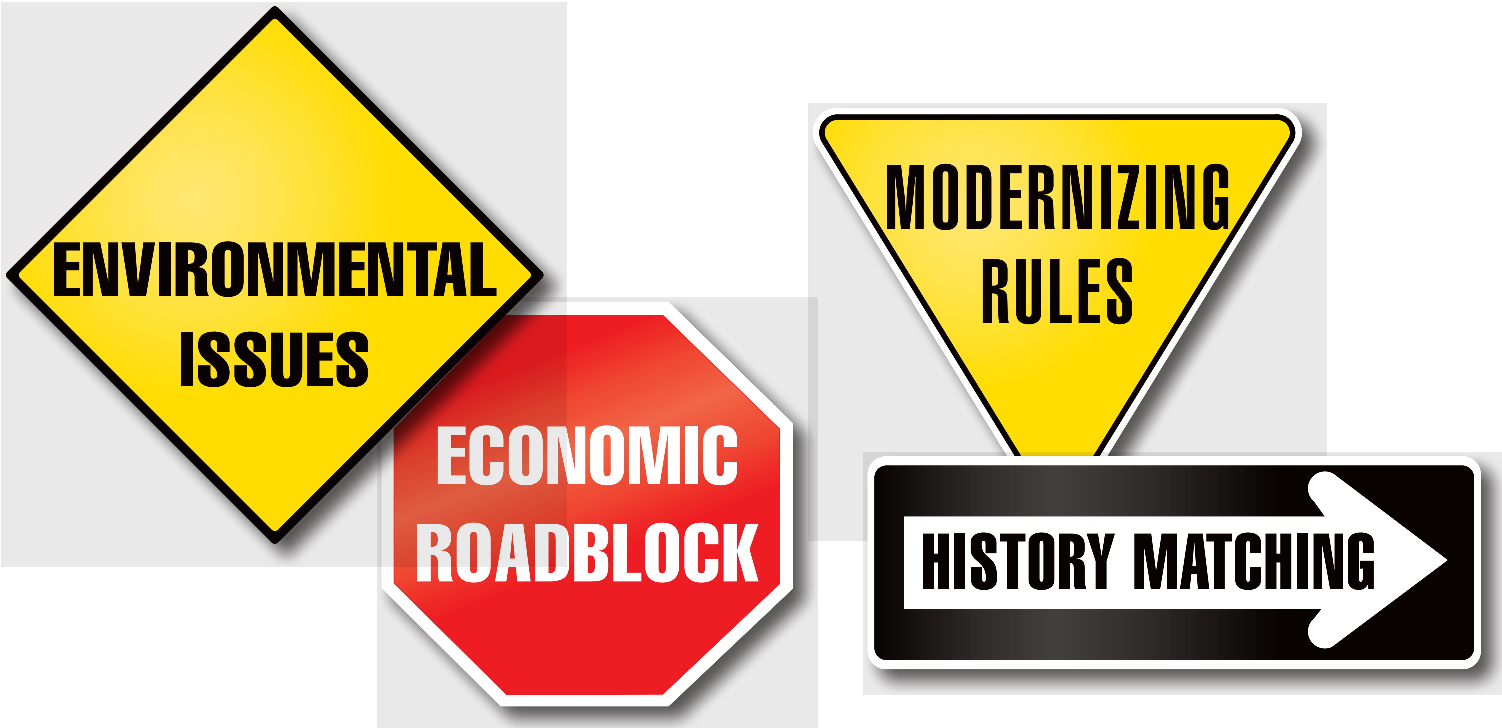


reserves roadmap

AS OILSANDS PLAYERS SEEK TO TURN RESOURCES INTO RESERVES, REGULATORY AND TECHNICAL GUIDELINES ARE EVOLVING

PLUS Coiled Tubing Unconventional Gas Production Water Treatment



reserves roadmap

AS OILSANDS PLAYERS SEEK TO TURN RESOURCES INTO RESERVES, REGULATORY AND TECHNICAL GUIDELINES ARE EVOLVING

BY SUSAN EATON

This fall, the U.S. Securities and Exchange Commission (SEC) plans to modernize its reporting rules for booking oil and gas reserves, in response to growing investment in unconventional resources, and to acknowledge changes in technologies required to extract non-traditional resources, including Alberta's vast bitumen deposits. Exploration and production (E&P) companies active in Alberta's oilsands welcome this long-overdue regulatory overhaul, as they've been penalized by the SEC's stringent requirements of recognizing only proven reserves, leaving significant upside on the table and negatively impacting corporate financial valuations for companies with unconventional assets. Borrowing heavily from the current oil and gas reporting requirements endorsed by the Canadian Securities Administrators, the proposed SEC changes will result in more closely aligned reporting practices on both sides of the border.

In Canada, the Canadian Oil and Gas Evaluation Handbook (COGEH) sets the standard for "best practices" in reserves evaluation practices, providing a framework that includes methodology and definitions for oil and gas resources and reserves. In addition, Canada's National Instrument (NI) 51-101 Standards of Disclosure for Oil and Gas Activities outlines the requirements and standards for disclosure by reporting issuers engaged in oil and gas activities. Combined, these two reference documents create the Canadian Securities Administrators' roadmap, which dictates how E&P companies — and third party, independent reserves estimators — must evaluate oil and gas properties.

Yet, in Canada, interpretations differ across the board in the implementation of this roadmap — especially when it comes to the evaluation of Alberta's unconventional bitumen deposits. A third and anticipated revision of the COGEH, expected in early 2009, aims to standardize resources and reserves guidance specific to both oilsands mining and in-situ projects.

"There are no specific oilsands evaluation guidelines," says Doug Ho, vice-president of engineering with Calgary-based Sproule Associates Limited, a firm specializing in reserves evaluations. "When you don't have guidelines, people have many different interpretations."

RESOURCE ASSESSMENT
Southern Pacific completed seismic and core hole test programs last winter on various portions of its 175 net sections near Fort McMurray, Alberta, resulting in the identification of its McKay block as its first project area.

In the absence of guidelines specific to oilsands — including acceptable exploration and production technologies and an agreement on requisite well densities per section, Sproule and its peer companies have each compiled their own in-house evaluation processes — based on their knowledge and expertise — while upholding the COGEH's definitions and the reporting requirements of the NI-51-101. These "made in Alberta" roadmaps describe the technical, fiscal and regulatory steps required to take an undeveloped oilsands lease from a rank exploration stage — a greenfield project — to a full-blown mining or in-situ thermal operation.

Robin Bertram, vice-president of engineering with AJM Petroleum Consultants, a Calgary-based reserves evaluation company, says it is common for people to interchange the words "resources" and "reserves," possibly misleading the unsophisticated investor or stakeholder. "Private companies and foreign nationals quite happily use any word that's going to promote their agendas," he says. "Canadian issuers need to be very careful."

"At the end of the day, there's still a wide range of resources and reserves numbers coming out of oilsands evaluations, due to the lack of guidelines and the misuse of analogs for thermal projects," adds Ho. "People tend to simplify things, but the geology is very complex." According to Ho, the quality of an oilsands lease depends not only on the technical data acquired to evaluate the lease, but on the selection of suitable analogs from other steam-assisted gravity drainage (SAGD) projects to assist in the selection of key parameters like steam-oil ratios (SORs) and bitumen recovery factors. However, there aren't a lot of analogs to choose from, as there are currently

Resources vs Reserves

THE CONFUSION BETWEEN RESOURCES AND reserves lingers across the industry: in its enthusiasm to describe Alberta's vast bitumen endowment, even the Energy Resources Conservation Board (ERCB) interchanges the term "reserves" for what most evaluation engineers would call "resources." However, to unravel this confusion, one simply needs to return to the Canadian Oil and Gas Evaluation Handbook (COGEH) guidance and the NI-51-101 reporting requirements.

In its June release of its annual report, entitled Alberta's Reserves 2007 and Supply/Demand Outlook 2008-2017, the ERCB estimates that the total bitumen resource in place is 1.712 trillion barrels — of that, the ERCB states that roughly 10% (or 172.7 billion bbls) represents the total remaining established reserve, based on current technology, as well as current and anticipated economic conditions. Further, for 2007, the ERCB increased its estimate of the remaining established reserves under active in-situ development, from 2.43 billion bbls to 3.72 billion bbls, due to the assessment of new and expanded projects approved during the last several years.

Given the foregoing, a back-of-the-envelope calculation suggests that the vast majority of Alberta's bitumen deposits are at various stages along the oilsands development continuum — seismic acquisition, exploration and delineation drilling, reservoir simulation studies, waiting on regulatory approvals or under construction. In fact, according to the government of Alberta, close to 67% of possible oilsands areas are still available for exploration and leasing.

Clearly, if the ERCB were held to the stricter guidance of COGEH and the reporting requirements of NI-51-101, it would be hard pressed to convey to the world the vast economic potential of Alberta's oilsands resource.

only 12 commercial SAGD projects in operation in Alberta.

E&P operators and reserves evaluators rely on key types of technical data for reserves classification, including geological and geophysical (seismic) mapping, the drilling and coring of wells, and reservoir engineering and simulation modelling.

"There's been differences [of opinion] in what kinds of data are required, in order to assign resources," says Philip Welch, president and managing director of McDaniel & Associates Consultants Ltd., a Calgary-based reserves evaluation firm. "You have the recent emergence of the oilsands junior," says Welch, "and they have these huge leases with virtually no drilling or delineation."

During the past five years — in a northern land grab of unprecedented proportions since the frenzied activity of the Klondike gold rush of 1897-1898 — large and small oil and gas companies alike have invested significant amounts to purchase Alberta's oilsands leases. The general consensus amongst reserves evaluators, however, is that latecomers to the oilsands game have picked up leases on the periphery of the fairway, lands that are poorer in reservoir quality and which are not supported by infrastructure. Thus, not all oilsands leases are created equally, and not all may have the "right geological stuff" to move to the development stage, given current extraction technologies and current commodity prices. Ho calls SAGD extraction an "unforgiving recovery process," and explains that it is best suited to reservoirs exhibiting high permeability and high bitumen saturations.

Because it takes, on average, three to six years from the greenfield stage to regulatory approvals, for both mining and in-situ projects, timelines and capital invested are key with respect to booking reserves for an oilsands project. In turn, it takes several more years to construct facilities and to produce the first barrel (bbl) of bitumen.

"The market is trading on contingent resources, for oilsands properties, because it takes so long to get to the reserves stage," explains Ho. In comparison, he says, "When you look at conventional oil and gas properties, the market is trading on reserves. And, there's a big risk between resources and reserves in oilsands projects."

Bertram echoes Ho's comments: "For companies to move their projects from contingent resources to proved reserves, it requires time and money. And, it's tough for small E&P companies to move along the oilsands development pathway, because it's so capital intensive."

During the process of turning resources into reserves, E&P companies, especially the oilsands juniors, demonstrate the increasing value of their oilsands leases, facilitating access to capital required for the ongoing development of their properties.

SAGD roadmap

More than 80% of Alberta's estimated 1.712 trillion bbls of bitumen resources is buried at depths greater than 75 metres, the economic depth for mining extraction. With the exception of the Cold Lake oilsands area, where cyclic steam stimulation is the production technology-of-choice for tight or low permeability reservoirs, the majority of E&P operators currently plan to employ SAGD to extract bitumen from the Athabasca oilsands fairway.

Prospective resources sit at the bottom of the oilsands development continuum — they represent the most uncertain category of resources, and are the least-documented technically. For example, prospective resources might be estimated using two-dimensional seismic data for regional mapping, and by integrating historical well data on or near the oilsands lease. Prospective resources are elevated to contingent resources based on activity on the lease: the discovery of bitumen by the drilling (and coring) of at least one well per section, the acquisition of additional 2D or 3D seismic data for prospect mapping and the integration of other data, including analog SAGD projects, thus generating strong geological confidence in the resource base. Contingencies — or hurdles — to the future development of these bitumen resources can include economic, legal, environmental and political issues, regulatory approvals and the absence of markets.

Moving up the food chain, the transformation of contingent resources to proved reserves is a two-step process — each step represents an escalation in capital expenditures and an increased commitment by the company to proceed to the development stage. Probable reserves (the first step) can be classified, based on a minimum of four wells per section, a firm corporate commitment to spend capital within five years and the submission of the regulatory approval with no significant issues raised by the stakeholders. Probable reserves must also pass a commerciality test — the development of probable reserves must be economic, under either constant or forecast pricing, while taking into account all future capital expenditures.

In the second and final step — the elevation of probable reserves to proved reserves — E&P operators must have regulatory approvals in place from Alberta's Energy Resources Conservation Board (ERCB) and Alberta Environment. Additionally, the ERCB requires operators to drill a minimum of eight wells per section, and to acquire 3D seismic data for detailed mapping and for reservoir engineering purposes; in the absence of 3D seismic data, the ERCB accepts 16 wells per section. From the reserves evaluator's perspective, the third and final criterion for booking proved reserves is a firm corporate commitment — and an allocation of capital within three years — to advance to the development stage.

Oilsands juniors

Byron Lutes, president of Calgary-based Southern Pacific Resource Corporation, has his eye on the goal post — steam injection by 2011 at the McKay SAGD project — and is moving his oilsands junior along the oilsands development continuum at record speed. In the 24 months since the company acquired a net 175 sections in five core areas in the heart of the Athabasca fairway, Southern Pacific has acquired 2D and 3D seismic data and has drilled and cored 70 wells. According to Lutes, an engineer, Southern Pacific has focused the bulk of its capital expenditures on one key project, McKay, which is situated two townships southwest of Petro-Canada's MacKay River SAGD project.

Based on a recent reserves report by McDaniel & Associates, Southern Pacific stated in August it has 3.6 billion bbls of discovered petroleum initially in place on its five properties — contained within this large resource are contingent resources ranging from 92 million bbls (low case) to 138 million bbls (best case) to 204 million bbls (high case). Further, the reserves report supports Southern Pacific's application for a 10,000-bbl-a-day SAGD operation at McKay.

"Our credibility will continue to evolve as the project gets rolling and we have a team in place that can get us to production — our drive and corporate objective is to get to cash flow as quickly as we can," says Lutes. "This isn't a land play anymore; this is about cash flow and profitability." According to Lutes, Southern Pacific has sufficient working capital on hand to complete the necessary elements required for an application to the ERCB and Alberta Environment for its McKay SAGD project.

However, there's still a lot of technical work to complete, he explains, prior to filing its McKay application to the ERCB in June 2009, a step that will transform Southern Pacific's contingent resources within the McKay project to probable reserves. As per the COGEH guidance, Southern needs to increase the well spacing from four to eight wells per section and to acquire 3D seismic over the McKay project area. Targeting ERCB approval in June 2010, Southern anticipates booking proved reserves, once it has achieved this regulatory milestone.

Southern Pacific is currently conducting reservoir modelling using STARS (Steam, Thermal, and Advanced Process Reservoir Simulator), a flow simulator developed in Calgary by Computer Modelling Group Ltd. "STARS allows for heat transfer," explains Lutes. "Most other black oil simulation models assume a constant reservoir temperature — you need to allow for both convective and conductive heat." Adds Lutes, "It's quite a different kind of simulator."

STARS simulates the transfer of heat from steam to the adjacent reservoir and will be used to model SAGD production performance, including the SOR, which determines the number and location of the well pairs and the steam boiler capacity. Southern Pacific expects to drill six SAGD wells pairs per pad, with a total of 18 well pairs for the initial startup of operations.

CORE TESTING
Left: Southern Pacific Resource's core drilling program at Leismer was completed last winter. Right: Cores extracted from the company's McKay block to be used to assess oilsands resource.

Lutes describes how Southern Pacific employs "history matching" — it's testing the flow simulator on Petro-Canada's MacKay SAGD project, one of the most mature projects in the province — to validate the assumptions used in the model for Southern Pacific's McKay. "The closest production to us has very similar looking reservoir quality, in terms of permeability, porosity and bitumen saturation," says Lutes. History matching, from a real-life SAGD operation, he says, enables Southern Pacific to do a reality check on what the simulator is spitting out.

Road ahead

In 2007, there were more than 3,100 oilsands agreements in place with the province of Alberta. During the next decade, estimates for capital expenditures for in-situ, mining and upgrading projects range between $68 billion and $125 billion.

As new projects in the pipeline queue up for regulatory approvals, escalating construction costs, inflationary pressures and heightened competition for skilled labour, supplies and services, introduce time delays and impact the economics of oilsands projects. Even the group of "usual" suspects — the multi-national E&P companies with historical in-situ and mining operations — are experiencing lengthy time delays in bringing projects onstream, not to mention huge cost overruns which, in some cases, have exceeded their capital budgets by 50 to 100%. Given that project commerciality is a key criterion for booking probable and proved reserves — and proceeding to the development stage — the road ahead may prove rocky for some oilsands E&P companies. ntm

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