September 15, 2008

Ms. Florence Harmon
Acting Secretary
Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549-1090

Re: File No. S7-15-08 -- *Modernization of the Oil and Gas Reporting Requirements*

Dear Ms. Harmon:

Cambridge Energy Research Associates (CERA) is an independent research firm that provides insight into the energy future.

In February 2005, CERA released a report entitled *In Search of Reasonable Certainty* that represented the culmination of a six-month research project supported by a diverse group of 32 separate organizations and involving the participation of at least twice that number[1]. In that report, CERA sought to illuminate how the current system for estimating and reporting oil and gas reserves came into being and to understand the problems that resulted from nearly three decades of major changes in four key areas: technology, the geography of the oil industry, the type of projects being executed by the industry, and the structure of markets for oil and gas. It identified opportunities for modernization in response to each set of changes. The conclusions of the report were that the current system had failed to keep pace with the changes in the industry and was in urgent need of modernization.

Following this project, CERA embarked on a second phase research program, which was supported by 30 organizations and involved at least double that number in the workshops. This resulted in a second report, *Modernizing Oil and Gas Reserves Disclosures*, which CERA issued in February 2006. Among the conclusions of this report were two significant prescriptions: the inclusion of oil sands reserves in oil and gas disclosures and the use of an annual average price for determining reserves volumes (for the year ending three months prior to the balance sheet date of the reporting company).

The recommendations in these reports reflected CERA's analysis and also drew upon the views of the study program participants. CERA presented both reports to the SEC in June 2006 and recommended that the SEC consider conducting a broad

[1] The participating organizations included oil companies, financial auditors, law firms, reserves estimators, industry associations, professional societies, financial investors and policy makers.

consultation with all stakeholders with a view to modernizing oil and gas reserves disclosure rules.

CERA commends the SEC for the thoroughness of its consultation and its determination to modernize the rules. We do, however, have three comments which we hope will be useful to the SEC as it proceeds with its deliberations.

1. The overarching principle underlying CERA's recommendations was to provide consistency between the information provided to users of reserves disclosures and the information provided to users of financial statements However, the new rule proposal issued by the SEC would require two different bases for estimating reserves:

   - a single day year-end price for unit of production calculations in estimating proved reserves to be disclosed in financial statements, and
   - an annual average price for estimating economically producible reserves to be disclosed outside of the financial statements.

   CERA believes that this can only cause confusion and potentially mislead investors who will assess the profitability of exploration and production companies using financial statements that are prepared on the basis of estimates that are different from the reserve estimates used by company managements for making exploration and production decisions. It makes more sense to use a single calculation of reserves—based on annual average prices to reduce the volatility of estimates and create greater comparability between different companies' reports.

2. CERA's research program identified the complexities of preparing reserves estimates, particularly for companies with larger, more diverse portfolios. The earlier that the price for estimating reserves is determined, the more efficiently reserves estimates can be prepared. CERA's recommendation was that a reporting company should calculate the annual average price for reserve evaluations three months before the end of its financial year. CERA recommends that this principle be incorporated into the SEC's proposal.

3. Finally, it seems that the current proposals may have underestimated the inherent complexity of the upstream oil and gas industry, especially as it has evolved since the 1990s. Many of the more granular proposed reporting requirements seem geared to the traditional onshore, mid-continentview of the industry described in *In Search of Reasonable Certainty.* This "Texlahoma" perspective predominated when the current disclosure system was conceived. The industry has changed a great deal since then. The granularity and depth of disclosure required by the proposed rules are inconsistent with the complexity of major projects and the integration of multiple technologies and know-how in assessing reserves that now characterize the industry. One of the principles of the existing rules is that they can be applied equally to large companies and small. Increasingly, modern day projects draw upon the integration of multiple technologies and the collaborative efforts of many different experts. The proposed rule appears excessively burdensome on organizations that develop

large, complex assets. In this instance, the new disclosure regime would be inconsistent with the four transforming changes in the industry noted above.

Again, we commend the SEC on this major step forward in modernizing reserves reporting and hope that these three comments will be helpful in determining the path forward. We are enclosing copies of both of the CERA studies referenced above with this letter. Should you wish to discuss any of the conclusions or recommendations of these studies, we would be delighted to do so.

Yours sincerely,

Cambridge Energy Research Associates

Modernizing Oil and Gas Reserves Disclosures

SPECIAL REPORT

Cambridge Energy Research Associates
February 2006

CERA®
An IHS Company

AUTHORS

Daniel Yergin, Chairman, CERA

David Hobbs, Managing Director, Oil and Gas Research, CERA

COAUTHOR

Richard Ward, Director, CERA

PROJECT ADVISORS

Julian West, Senior Director, CERA

ACKNOWLEDGMENTS

Peter Augustini, Bethany Genier, Lindsay Gorzeman, Peter Jackson, Amy Kipp, Lauren Laidlaw, Robert Lockwood, Ellen Perkins, Luke Ryder, Linda Sanders, Anna Warrock.

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Finally, we would like to acknowledge the support of our colleagues at IHS, Inc.

Cambridge Energy Research Associates, Inc. (CERA), an IHS company, is a leading advisor to international energy companies, governments, financial institutions, and technology providers. CERA delivers critical knowledge and independent analysis on energy markets, geopolitics, industry trends, and strategy. Our services help decision makers anticipate the energy future and formulate timely, successful plans in the face of rapid changes and uncertainty. CERA is valued for our independence, fundamental research, foresight, and original thinking. Our unique integrated framework enables us to offer new insights ahead of conventional wisdom, providing a comprehensive "early warning system" that has a direct impact on investment, decision making, and performance.

CERA has over 200 staff worldwide, with offices in Cambridge, Massachusetts; Bangkok; Beijing; Calgary; Dubai; Johannesburg; Mexico City; Mumbai; Moscow; Oslo; Paris; Rio de Janeiro; San Francisco; Singapore; Tokyo; and Washington, DC.

55 Cambridge Parkway
Cambridge, MA 02142, USA
Tel: +1 617 866 5000 • Fax: +1 617 866 5900
www.cera.com

For more information on this study, contact info@cera.com

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Royal Dutch Shell

Ryder Scott

Society of Petroleum Engineers

Suncor

Talisman Energy

TNK-BP

Total

AUTHOR BIOS

DANIEL YERGIN is a highly respected authority on international politics and economics and on energy. Dr. Yergin is a Pulitzer Prize winner and recipient of the United States Energy Award for "lifelong achievements in energy and the promotion of international understanding." He is chairman of Cambridge Energy Research Associates (CERA).

Dr. Yergin received the Pulitzer Prize for General Nonfiction for his work *The Prize: The Epic Quest for Oil, Money and Power,* which became a number-one national best seller and was made into an eight-hour PBS/BBC series seen by 20 million people in the United States. The book has been translated into 12 languages. His latest book, *The Commanding Heights: The Battle for the World Economy,* has received wide attention for its analysis and narrative of how the "world is changing its mind about markets and government." It has been translated into 13 languages and made into a six-hour PBS/BBC documentary.

Dr. Yergin is a member of the US Secretary of Energy's Advisory Board and chaired the US Department of Energy's Task Force on Strategic Energy Research and Development. He is a member of the Board of the United States Energy Association, a member of the National Petroleum Council, and a member of the "Wise Men" for the International Gas Union. Dr. Yergin serves as CNBC's Global Energy Expert. He is a Trustee of the Brookings Institution and a member of the Committee on Studies at the Council on Foreign Relations. He is also a Director of the US-Russia Business Council, the Atlantic Partnership, and the New America Foundation. Dr. Yergin received his BA from Yale University and his PhD from Cambridge University, where he was a Marshall Scholar.

DAVID HOBBS, CERA Managing Director, is an expert in oil and gas commercial development. He leads CERA's research activities in oil markets, liquefied natural gas, technology, and environmental strategies. He also heads CERA's E&P Strategy Service, focusing on strategy development and the analysis of international activity.

Mr. Hobbs is an author of the major CERA study *In Search of Reasonable Certainty: Oil and Gas Reserves Disclosures,* a comprehensive analysis of the problem of assessing reserves. He is also a principal author of the CERA Multiclient Study *Harnessing the Storm—Investment Challenges and the Future of the Oil Value Chain* and the author of the CERA Private Report *Daring to Be Disciplined: Continuous Portfolio Improvement.*

Prior to joining CERA, Mr. Hobbs had two decades of experience in the international exploration and production business, more recently as head of Business Development for Hardy Oil and Gas. He was also Commercial Manager with Monument Oil and Gas and a drilling engineer with British Gas. He has led projects in Asia, South America, North America, and the North Sea. He has led major international investment and asset commercialization operations; negotiated acquisition, divestment, and partnership transactions; and arranged funding. Mr. Hobbs holds a Bachelor of Science degree from Imperial College.

RICHARD WARD, CERA Director, is an expert in oil and gas exploration and production (E&P) information technologies, including strategic applications, market advantage, and financial strategies of technology use. He is one of the leaders of CERA's Digital E&P Strategies Service.

Prior to joining CERA, Mr. Ward was Vice President, Technology, of NetworkOil, Inc., where he was responsible for scoping, developing, and implementing the company's critical e-business technology systems. Formerly Mr. Ward was Vice President of Sales and Marketing for Maurer Engineering, a specialized drilling technology firm. He previously spent seven years with Landmark Graphics in various management roles for this major E&P software company. Mr. Ward has managerial experience in Latin America and Southeast Asia as well as in the United States and was Adjunct Professor of eBusiness at the Jones School of Management, Rice University, focusing on technology issues affecting the energy industry. He holds a BA from Rice University.

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CHAPTER 1: BEYOND THE SEARCH FOR REASONABLE CERTAINTY

This CERA Special Report *Modernizing Oil and Gas Reserves Disclosures* builds on the recommendations of CERA's February 2005 Special Report on oil and gas reserves and consolidates stakeholder opinion that it is time to:

- modernize the United States Securities and Exchange Commission's (SEC) oil and gas reserves definitions and disclosure requirements and segregate the SEC's compliance role from rule making
- delegate responsibility for defining oil and gas reserves and associated guidelines for SEC rule making in this area to the Society of Petroleum Engineers (SPE) through the vehicle of the SPE's Oil and Gas Reserves Committee
- use the forum of the SPE Oil and Gas Reserves Committee to establish best practice regarding emerging issues on reserves

These recommendations are based on wide-ranging consultation with a broad study group since publication of our February 2005 Special Report *In Search of Reasonable Certainty*.*

DIAGNOSING THE PROBLEM

The February 2005 Special Report identified four primary ways in which the SEC's reserve disclosure regime—referred to as the "1978 System"—had become outdated and in need of modernization. These related to

- **Globalization of the industry and capital markets.** Less than 20 percent of SEC registrants' reserves are located in the United States today, compared with more than 65 percent when the reserves reporting system was established in 1978.
- **Technological advances.** With technological innovation transforming what were previously considered to be noncommercial resources into future proved reserves, the current SEC system remains rooted in the technology of the 1970s and lacks a consultative forum or process to address technological change in reserves evaluation. Yet companies rely on these modern techniques to support multibillion-dollar investment decisions.
- **Changed anatomies of major projects.** Nontraditional projects are drawing an increasing proportion of exploration and production (E&P) expenditures. CERA expects production from two such nontraditional resources discussed in more detail in this report—extra heavy oil (in both Canada and Venezuela) and gas-to-liquids (GTL)—to grow to nearly 6 million barrels per day (mbd) by 2015. Not all of these resources are adequately accommodated in the present system of reserve disclosures.

*In the course of conducting the research and analysis to produce the February 2005 Special Report, CERA organized a study group of 30 oil and gas, accounting, reservoir consulting, and law firms to support the research and consulted with more than 150 individuals knowledgeable about the subject in multiple workshops in Washington, DC, Houston, London, and Moscow and a workshop in New York for the investment community. CERA's study team comprised ten of the firm's researchers, as well as Professor Joseph Pratt, Cullen Professor of History and Business at the University of Houston, and his associates, Will Baxter, Tyler Priest, Mark Schmidt, and Joseph Stromberg.

To conduct this further research and analysis, CERA organized a study group of 30 oil and gas, accounting, and reservoir consulting firms; industry associations; and professional societies to support the research and consulted with more than 130 individuals knowledgeable about the subject in multiple workshops in Washington, DC, Houston, London, and Calgary and a workshop in New York for the investment community.

- **Globalization and commoditization of oil and gas markets.** Deregulated gas markets have emerged in Europe and North America, along with third-party access regulations. Furthermore, the highly liquid, deeply traded spot markets for oil and gas, which did not even exist in the 1970s, have significantly increased the daily volatility of prices.

The 1978 System focuses on proved reserves as defined by a standard of “reasonable certainty” pegged to “direct contact” with an existing well. This measure may be suitable for reserves forecasts of individual producing wells but is unsuited to an increasing proportion of the modern oil and gas industry, particularly to larger offshore projects. The result can be to disconnect many companies’ official reserves disclosures from the reality of their investment plans and decision making processes.

In contrast to the SEC approach, the definitions promulgated by the Society of Petroleum Engineers, the World Petroleum Congress, and the American Association of Petroleum Geologists—among the most prominent technical organizations operating in this arena—incorporate the changes that have occurred in the industry during the past two decades. These standards recommend the use of all available data that companies employ for internal investment decisions. Furthermore, the United Nations Framework Classification, as it relates to petroleum, is consistent with SPE definitions for oil and gas reserves and resources. It has apparently been adopted recently by the Russian government. The International Accounting Standards Board may, following its own analysis and consultation, adopt definitions consistent with those of the SPE.

The Society of Petroleum Engineers

The SPE draws together the scientific and engineering expertise of the oil industry. A professional society for experts in petroleum exploration, development, and production with an international membership of 60,000, it provides the leading forum for the exchange of ideas and best practices. It has a number of peer-reviewed publications, and conducts meetings and workshops around the world in which technical papers are presented and discussed by the membership. One of its standing committees, the Oil and Gas Reserves Committee, is concerned with reserves definitions and guidelines, and it has issued multiple updates to these since 1964. It is closely related, by virtue of common membership, to the Society of Petroleum Evaluation Engineers, which focuses more narrowly on issues surrounding reserves evaluation.

ACTING ON THE DIAGNOSIS

The study group identified a broad consensus on the key steps: the separation of rule making from compliance coupled with bringing the right level of technical expertise and experience to the rule making process to ensure that the desired modernization is achieved. The resources currently available within the SEC to manage this task, as well as the ongoing function of compliance monitoring, are probably too few. Furthermore, the research process revealed a strong desire that changes to the rules and guidelines should only be made following broad, public consultation.

This Special Report concludes that an effective way to modernize the 1978 System and keep it up to date would be to adopt the SPE reserves definitions and guidelines and transfer responsibility for maintaining and updating these definitions to the SPE. This would be consistent with how the SEC works with the Financial Accounting Standards Board to establish and maintain financial accounting standards. Adopting this approach will free the SEC to focus on compliance and to engage with stakeholders of the E&P industry to ensure the effective management of the reserves disclosure process.

This report provides the history of and arguments for moving forward with the above proposals. First, we provide some context on the conclusions from our February 2005 Special Report *In Search of Reasonable Certainty*. We then reflect on industry practices and examine organizational models for “rule making” in Chapter 3. To reinforce this need, we discuss in Chapters 4 and 5 the anachronism of the use of year-end oil and gas prices for calculating reserves, the growing contribution of nontraditional resources, and the particular challenge that the Canadian oil sands may pose to reserves recognition unless a modern, more dynamic approach is adopted.

CHAPTER 2: REVIEW OF THE FEBRUARY 2005 SPECIAL REPORT

Our analysis and core conclusions build upon the work behind the February 2005 Special Report *In Search of Reasonable Certainty*. This chapter highlights the key arguments of that report only as they relate to the specific focus of this CERA Special Report.

THE INCREASING IMPORTANCE OF RESERVES REPORTING

Disclosed reserves should represent estimates of the volume of hydrocarbons that oil and gas companies believe that, based on scientific and engineering analysis, they can commercially produce with reasonable certainty over the years ahead. Companies also recognize that they will be judged and evaluated against these predictions. The ability of companies to meet these expectations is at the core of the relationships of trust with their shareholders and other stakeholders.

Reserves data are used by a variety of stakeholders for multiple purposes. As a result, the way reserves are estimated and communicated is very important. This is particularly true in light of the challenge facing the oil and gas industry to add new supplies in the years ahead. Meeting demand for oil—and for a doubling in global demand for natural gas—will require continuing technological advancement, innovation, megaprojects measured in billions of dollars, increasing development of “nontraditional” oils, shifting geography, and flexible markets. Yet all these trends are not well accommodated by the 1978 System for reserves disclosure mandated by the United States Securities and Exchange Commission (SEC).

CERA’s assessment is that between $4.5 and $6 trillion will be invested in exploration and production (E&P) through 2030 to meet future global demand for oil and gas. Reserves are at the heart of the confidence and credibility necessary to ensure that the industry has the capability and access to funds needed to meet those huge needs. This adds further to the need to review, understand, and modernize the existing approach to reserves reporting to bring it up to date with the transformative changes that have taken place since the current rules were first promulgated almost three decades ago.

The current regulatory regime—the 1978 System—emerged as part of the response to the energy crises of the 1970s and fears about the vulnerability of the United States to dependence on foreign energy sources and future disruptions. It was originally intended to provide an inventory of how much domestic supply would be available to the United States. After Congress assigned the responsibility for this effort to the SEC, the 1978 System’s purpose gradually shifted over time to one of informing investors. The resulting system was rooted in the technologies and market structures of the 1950s and 1960s.

A SYSTEM UNDER STRESS

As it stands, the system mandated by the SEC is under stress. Yet this system has become the dominant regulatory system worldwide, with the SEC as a de facto global regulator. Companies reporting under the SEC classification of reserves account for some 40 percent of global oil and gas production and 10 percent of global reserves (the majority of which are not held by US-domiciled companies).

Companies, investors, and technical experts are increasingly questioning whether the current US system provides an accurate understanding of a company’s position or whether, on the contrary, it results in a view of reality that diverges from the one used by a company—or, in aggregate, by the industry—for making investment decisions. Several aspects of this system stand out:

- The current 1978 System has not been revised in any significant way and its interpretation has not kept pace with major changes that have since occurred in the industry landscape, in terms of both the commercial arrangements used and the development of technologies that underpin reserve estimates.

- The interpretation and application of the current system is inconsistent with the way in which the managements of oil and gas companies make investment decisions—which is the view in which investors are interested.

- Reserve estimation is an integrated activity cutting across several technical and commercial disciplines including geology, geophysics, reservoir engineering, facilities engineering, statistics, contract law, and economics. It is a process of continual learning, dialogue, sharing, and consultation. Yet the 1978 System has become increasingly rigid and discipline-focused in this respect. This makes it harder to incorporate new innovations and technological advances into the rules.

- When adopted in the late 1970s, the SEC rules applied to US registrants, and some two thirds of their reserves were in the United States. It is doubtful that policymakers foresaw the extent of the globalization of capital markets and the geographical expansion of US-domiciled companies that would lead today to the SEC's becoming a de facto global regulator. But that is certainly the case. Many of the largest foreign registrants today were then, prior to their privatizations, in fact state-owned companies. There has been a migration away from "Texlahoma," a mythical composite of Texas, Oklahoma, and Louisiana that we use to represent conventional onshore operations and that made up a significant share of the North American industry in the 1970s. The proportion of registrants' reserves located in the United States had fallen to 16.8 percent by the end of 2003 and to 16.6 percent by the end of 2004.*

The United States led the way in the 1970s in creating a disclosure system for oil and gas reserves. Many other countries do not require formal disclosure of reserves in E&P company financial statements, and of those that do, there are two main definitions for reserves. One is the Society of Petroleum Engineers (SPE) definitions, which were the basis for the original SEC definitions (but the interpretation and application of the SPE definitions have evolved to reflect current industry practices). The second is the Soviet/Russian definitions, which appear to be in the process of being replaced by the SPE definitions through the adoption of the United Nations Framework Classification (UNFC).** In addition, drawing on the SPE definitions, Canada has introduced new disclosure rules under National Instrument 51-101 and published the *Canadian Oil and Gas Evaluation Handbook*, which provides more detailed guidance to companies filing under Canadian rules.

Over the past nearly three decades, the gap between the application of the SEC definitions and the SPE definitions has widened—and continues to do so. Times change, and the SPE definitions and guidelines have changed with them. That has not been the case with the SEC practices, which have often lagged the changes.

Whereas once the outcome of calculating SEC or SPE reserves would have been the same, today the differences can be appreciable; the SPE definitions and methodology more closely reflect current industry practices and global perspectives. Most midsize and large companies use the SPE definitions for internal purposes and base their investment decisions on a range of outcomes including proved and probable reserves, or mean reserve volumes.

*John S. Herold, Inc. and Harrison Lovegrove & Co, *2004 and 2005 Global Upstream Performance Review.*

**The United Nations has published a framework for classifying energy resources that was adopted at the November 2003 meeting of the United Nations Economic Commission for Europe Committee on Sustainable Energy. The UNFC is based on the SPE definitions for oil and gas reserves.

THE CHANGING OIL AND GAS INDUSTRY

As we have already observed, the industry has changed significantly during the past 28 years in terms of its geography, technology, types of hydrocarbons being recovered, and globalized markets for its production.

These changes have been so significant that one of the most important original users of the disclosures—the US government—draws increasingly on additional data (based on SPE standards) for analysis of security of supply and long-term energy policy planning. The 1978 System is more resilient to some of these changes than to others; but the common underlying theme is that the industry has changed in ways that, understandably, could not have been readily foreseen at the time the rules were put in place. For instance, when the 1978 System was promulgated, US oil and gas prices were controlled, spot trading was only just beginning, and futures markets were not yet in existence.

We are living in a period when the definition of what constitutes "oil" is widening. Developments under way with heavy oil production, such as from Alberta's oil sands and Venezuela's Orinoco Basin, mostly include upgraders so that they produce a stabilized crude oil that can be run in a wide variety of refineries, thereby significantly enhancing the marketability of the output. Increasingly innovative development schemes, designed to optimize the economics of extraction, involve integration of the different components of a project in ways that challenge conventional boundaries between upstream and downstream projects. Similarly, in recent years, gas-to-liquids has moved from a fringe activity (with commercial operations restricted to South Africa and one or two pilot plants elsewhere) to a wave of projects that are designed to be competitive on global markets. This results in very specific product outputs that have particular benefits as a blend stock for lube oil and in ultralow-sulfur diesel to meet ever-tightening quality specifications.

These developments illustrate the need for the kind of transparent consultation process that exists for accounting purposes but appears not to be operative for reserves reporting.

KEY RECOMMENDATIONS OF THE FEBRUARY 2005 SPECIAL REPORT

Separation of Functions (Standards Setting versus Compliance)

The growing strain on the regulatory system results in part from the overlap in the current regulatory regime between the job of setting the standards and measuring compliance against those standards. Accounting regulators have recognized the merits of separation of these functions (even where responsibility remains within the same umbrella organization). This kind of structural rearrangement for reserves disclosure would help bring technical reserves reporting into line with the US regulatory structure for financial reporting.

One of the aspirations of companies and investors alike is that reserves disclosures should be globally consistent. This can be achieved by moving toward a single global standard for establishing what constitutes proved reserves. The most generally accepted are the SPE, World Petroleum Congress, and American Association of Petroleum Geologists definitions, which would make them a logical foundation for a globally consistent disclosure framework. The SPE benefits from the input of professionals who are constantly engaged in the frontline of industry best practice. Allowing regulators to call on the SPE, a technical organization, to establish and codify best practice for determining and classifying reserves globally would serve all stakeholders well and would free regulators to focus more of their efforts on compliance rather than on the task of maintaining the currency of technical definitions.

Encouraging Public Consultation

The Financial Accounting Standards Board created an Emerging Issues Task Force to deal with accounting issues. Among the CERA study participants, there has been a good deal of discussion about an equivalent “emerging issues” body to debate questions such as the form and content of oil and gas reserves disclosure or questions arising out of individual compliance discussions that would benefit from a wider perspective. Such a body might usefully draw upon the expertise of the professional societies and other interested stakeholders to help regulators and the industry to develop common understandings and practices.

CHAPTER 3: REFLECTING INDUSTRY PRACTICES

INTRODUCTION

The significant changes in the industry over nearly three decades make a compelling case for modernizing the system to create a workable, constructive framework for the oil and gas industry in the twenty-first century that responds to the needs of all stakeholders.

Separating the role of creating and maintaining oil and gas reserves definitions and guidelines from that of monitoring the compliance of disclosures against those definitions and then bringing the expertise of a broad array of recognized technical experts to the rule making process would represent a giant stride toward achieving this objective. In this chapter we set out the arguments for delegating the rule making role to the Society of Petroleum Engineers (SPE) through its Oil and Gas Reserves Committee.

STRANDING OF REGULATIONS IN A DYNAMIC INDUSTRY

It is a credit to the robustness of the original drafting that the United States Securities and Exchange Commission's (SEC) reserves disclosure rules—the 1978 System—have remained as relevant to the evolving industry for as long as they have. The SEC, in line with the requirement of the Energy Policy and Conservation Act, adopted reserves definitions that were broadly consistent with those then used by the Department of Energy—based on work promulgated by the SPE in 1964. The SPE definitions have since been updated, or modernized, no fewer than three times. In each case the update conservatively reflected industry practices that had progressed from "new innovations" to common, proved, and widespread. In contrast, the current SEC regulations could be considered to be out of date and stranded in time against the backdrop of a fast-changing world.

A key purpose of reserves disclosures is to provide investors with the most accurate or best information concerning the state of a business and its underlying assets. What are they to think of the current gap that exists between a company's knowledge concerning proved reserves and what it is required or sometimes constrained to report? For example, in a case study documented in Appendix A, experts at a company believed that a particular field held 658 million barrels of oil classified as proved under SPE guidelines (i.e., with reasonable certainty or with 90 percent confidence) and using an SPE accepted technique: the pressure gradient method for determining the lower limit of the hydrocarbon accumulation.* However, under the current (and then extant) SEC guidelines the company was only permitted to disclose to the public that it possessed 261 million barrels of proved reserves. This represents a difference of $12 billion in future revenues at an average price of $30 per barrel—and $20 billion at $50 per barrel. How does such a discrepancy serve investors, especially since the two figures were developed using the same standards of rigor? The only difference is that one was informed by the methods of the 1960s—and the other, the 1990s.

*The pressure gradient method, explained in Appendix A, relates to the extrapolation of pressure measurements recorded in two fluids of different densities to determine the point of intersection.

A HISTORY OF SEPARATION

The US Congress created the SEC in 1934 to restore confidence in financial markets and vested it with the power to create rules, as well as to monitor and enforce them. However, in the oil and gas sector, the SEC seems to have focused more heavily on compliance and enforcement and seems to have applied fewer human resources to rule making. More broadly, the SEC has long accepted and even encouraged the role of the private sector in formulating and maintaining regulations. For example, it has allowed the private sector to set accounting standards while retaining for itself the regulatory authority to overrule them. This conscious separation of the powers of rule making from compliance and enforcement continues to this day.

In 1938 the SEC stated its policy that financial reports that followed accounting practices for which "there was no substantial authoritative support" were presumed to be misleading (Accounting Series Release No. 4). Although unwritten, but widely understood, the only authoritative support the SEC accepted came from a subcommittee of a professional society, the American Institute of Certified Public Accountants.

Later, the SEC transferred authority for regulation from the professional society to a purpose built entity, the Financial Accounting Standards Board (FASB). Accounting Series Release No. 150 stated, "principles, standards and practices promulgated by the FASB in its Statements and Interpretations will be considered by the Commission as having substantial authoritative support, and those contrary to such FASB promulgations will be considered to have no such support." This understanding has been continually reaffirmed, despite the FASB having no formal legislated standing.

THE CHALLENGE OF MODERNIZATION

CERA's central recommendation in the February 2005 Special Report was that the SEC follow precedent from the accounting area and separate the function of rule making from compliance monitoring as an important first step in modernizing the oil and gas reserves disclosure regime. Yet the separation of the functions of rule making and compliance will not, of itself, resolve all the modernization issues surrounding oil and gas reserves reporting.

The ultimate objective is a modernized set of definitions and guidance that are complemented by a process for ensuring that they stay current and reflect best practices as they emerge. The first part of this objective would be achieved by adopting the current published SPE definitions and technical guidance for establishing proved reserves. These represent the most widely accepted benchmark among SEC registrants, and there would be considerable and immediate benefit in updating SEC definitions and technical guidance to align with the SPE position. After all, the SEC's current 1978 System was modeled on the work of the SPE in the 1960s and 1970s. The second part of the objective requires some restructuring.

RESTRUCTURING OPTIONS

The ideal structure would provide access to a dynamic roster of technical expertise at little or no cost to the SEC (or incremental cost to the industry), while providing close linkage to the structures and culture of the SEC. As indicated in Chapter 1, CERA recommends the SPE Oil and Gas Reserves Committee as the integral body for providing the input to SEC rule making. CERA evaluated several other options with precedents in the SEC's history, namely, the FASB's extension to reserves rule setting; a new external entity modeled on FASB; a fully staffed group in SEC structured so that it can access expertise on an as-needed basis; and the ad hoc use of technical experts identified by the professional societies. These options and their respective drawbacks are outlined in more detail in Appendix B.

The restructuring recommendation is, therefore:

- to adopt the current SPE reserves definitions and guidelines as recommended earlier and
- to delegate the continuing modernization to the SPE's Oil and Gas Reserves Committee, on which the SEC would have full-time representation.

This option has precedent in the formation and continued operation of the FASB and, by retaining the same legal override regarding oil and gas reserves as the SEC has regarding accounting matters, such an approach may not even require new legislation. Freed of this burden, the current SEC team could then focus on operational compliance issues.

This option draws upon already established institutional infrastructure that has managed leadership succession in the past without any decline in the effectiveness and credibility of its work. The SPE definitions and guidelines are well respected, and reserves estimates that comply with these definitions have been demonstrated to be conservative over time. It would not, therefore, be unreasonable for the SEC to adopt the SPE definitions as written; indeed it would be consistent with the process used in 1978 to draft the current regulations.

Although the SEC would retain the legal right to modify the definitions and guidelines if it concluded that the SPE was not properly reflecting modern practice, in practice this authority would be called upon only in *extremis*. It would require some significant concern on the part of the SEC to move away from the most widely accepted global reserves definitions.

The proposed solution provides a means for regulatory modernization, industry debate, and SEC-informed development of technical guidance, while avoiding the practical challenges of securing initial and ongoing funding for a large staff or the creation of a new entity.

A TEMPLATE FOR CONTINUING INDUSTRY CONSULTATION

The benefit and purpose of continuing industry consultation is to help recognize and formalize established industry practices that are not specifically addressed in current definitions or guidance documents. The well respected SPE Oil and Gas Reserves Committee has the appropriate process and membership to fully consult and challenge emerging issues to ensure that guidelines can remain both current and conservative. The Committee provides technical guidance on appropriate and suitable application of new techniques when estimating reserves. These guidelines are thoroughly peer reviewed before publication, including the following steps (illustrated for the previously referenced field in Appendix A):

- **Publication in a professional journal.** Editors of professional journals seek to advance the state of their industry, while also avoiding a reputation for faddishness and irrelevance. Publication of an article or paper describing a technique provides a high level of legitimacy.
- **Discussion in multiple peer reviewed papers.** Peer review provides a mechanism for validation of principal claims, as well as discussion of limitations that often leads to guidelines in the application of a specific technique. Also due to the investment in time required by the peer review process, reviewers are reluctant to accept poorly supported arguments for consideration and review.

- **Demonstration of practical application.** If a technique has been demonstrated to have been used multiple times in the determination of reserves, and to have been accepted by decision makers as sound information to justify an investment decision, a case can be made for the practical application of the technique.

- **Guidance for the use of the technique has been posted publicly.** With emerging techniques that are proved by their practical application, many firms have developed internal guidelines for the conditions and use of such capabilities. These guidelines may stipulate the number of measurements required to meet a level of confidence, or indicate the exact geological conditions under which the technique is acceptable. A technique would become acceptable if the SPE Oil and Gas Reserves Committee publishes guidance on its use. In confirming compliance with the regulations, the SEC would seek evidence that companies had properly applied the guidelines.

CONCLUSIONS

The February 2005 CERA Special Report *In Search of Reasonable Certainty* concluded that separation of the responsibility for setting the rules from monitoring compliance is an essential step to free up the process of modernization. Consideration of various options for achieving this separation in practice leads to our recommendation that the SEC adopt the current SPE definitions and guidelines and to delegate the responsibility of updating these definitions and guidelines to the SPE Oil and Gas Reserves Committee. Most importantly, this would bring the skills of a well-recognized body of technical experts to bear on the rule making process.

This would allow the SEC to participate in greater collaboration with the industry and all its stakeholders while reducing the pressure on the compliance function within the Division of Corporation Finance at the SEC. By adopting these recommendations, the SEC's regulations governing oil and gas reserves disclosures will reflect the current state of the art in the SPE definitions and keep up with the ever-evolving hydrocarbon industry and its continuing technological advancement.

CHAPTER 4: COMPARABILITY AT WHAT PRICE?

THE IMPORTANCE OF COMPARABILITY

In the previous chapters we summarize the case for the separation of the roles of creating reserves definitions and guidelines and monitoring registrants' compliance with those rules. We recommended that the United States Securities and Exchange Commission (SEC) adopt the current Society of Petroleum Engineers (SPE) oil and gas reserves definitions and guidelines and that it should delegate the task of keeping these updated to the SPE Oil and Gas Reserves Committee. In this chapter we illuminate an area in which the failure to modernize the existing regulations may have undermined the very comparability that they are intended to ensure.

It has been argued that despite its apparent arbitrariness, the use of oil and gas prices in force on the final day of a company's financial year (the effective date of the reserves assessment) has the merit of ensuring consistency between disclosures of different companies. This is far from the case. A more stable indicator of prices, price differentials, and costs is needed to restore the comparability of disclosures.

The objective of providing some valid means of comparison between portfolios commands broad support. However, in today's industry, the mandated methodology for the calculations of reserve volumes and the so-called Standardized Measure of Oil and Gas (SMOG) does not actually provide the intended comparability.* As the CERA February 2005 Special Report *In Search of Reasonable Certainty* explained, the range of different project anatomies has increased, as has the cocktail of fiscal terms. The oil market has changed from one of controlled prices in regulated markets to one in which oil spot markets can exhibit fluctuations of several dollars in a day. Where gas spot markets exist, proportional changes can be equally large. Yet reserves are by definition a long-term proposition; the decision to develop them is not based on any day's prices but on expectations of prices over the life of the asset.

THE ARBITRARINESS OF YEAR-END PRICING

Many commentators accept that the use of a year-end price for estimating reserves is arbitrary, but nonetheless, this practice has the apparent merit of being a consistent number to be applied by all registrants from the exploration and production (E&P) industry. And yet this may only create an illusion of consistency and comparability. If the results of the analysis are only valid in relative terms, then the relative attractions of different portfolios would not normally be affected by short-term, transitory changes in the oil and gas prices but rather by longer-term systemic changes. Furthermore, if choosing different year ends creates radically different assessments of volumes and values for identical sets of underlying assets, then the illusion of consistency will be just that: an illusion. Later in this chapter we provide an illustration of the problem.

The 1978 System requires registrants to report the SMOG calculation in addition to the estimated proved reserves. The SMOG evolved out of a drive to introduce "fair value" accounting—a means to reflect the value of the oil and gas assets on the balance sheet of an E&P company rather than their cost.* Even at the time that it was mandated, three members of the Financial Accounting Standards Board (FASB) declared that the SMOG did not provide any reasonable measure of fair market value nor was it a reliable measure; but, by a majority vote, it was included.

*SMOG is an acronym for the **S**tandardized **M**easure of discounted future net cash flows from production of proved **O**il and **G**as reserves.

**This effort ceased when it became evident that volatility of valuations from one balance sheet date to the next and the number of variables involved in arriving at a "fair value" created more complexity than the issue it was designed to resolve—a situation that persists to this day.

There is no specific reason that the SMOG calculation should be based on the same pricing assumptions that are used to prepare the estimates of reserves volumes (other than convenience for the registrant of having to do the calculation only once). Nonetheless, in recent years the SEC has required that companies use the same prices for both calculations, and we believe this practice should be continued to promote better alignment and consistency between the disclosures. This chapter presents the case for adopting a more stable pricing methodology that we believe should be applied to both the estimation of reserves as well as the SMOG disclosure.

RESERVES ESTIMATION NOT A FULLY AUTOMATED PROCESS

Even before the reserve write-downs of 2004 and 2005, most E&P companies had written, documented procedures for compiling their reserves figures and for ensuring their quality control prior to publication. In this age of high technology and desktop IT, one might be tempted to imagine that the data for calculating the reserves for every field in a company's portfolio is stored in some "superspreadsheet" and that this repository of production profiles, fiscal regimes, quality- and location-based pricing differentials, and operating and capital costs (to name some of the components) is somehow all linked to a magic number—the year-end price—which can be input at the last minute, resulting in the delivery of a fully formed, SEC-compliant reserves disclosure.

In some respects it is the least complex, the lowest tech companies that are best placed to achieve such simplicity in their reserves calculations. The largest, most technologically advanced, most geographically diverse companies have portfolios that do not lend themselves to this approach. The reasons are sometimes related to the operating structures of companies—their geographical divisions being constrained through the decision-making processes and possible requirements for partner approvals in local joint ventures, or regulations that prevent them from integrating data with a head office—as well as the complexities of human judgment and experience that must be included in any reserves calculation to recognize the expectations of future capital expenditure budgets.

Proved producing reserves are not the problem here: their remaining potential is indicated by production performance and constrained by the term of the license under which they are being produced and their economic cutoff. It is proved undeveloped reserves that must be the subject of the owner's intent to develop those reserves. The capital spending decisions of successful E&P companies are not mechanically derived (i.e., any asset that shows an acceptable level of financial return would be developed); instead they are the result of disciplined investment processes that ration capital only to the more economically attractive projects, given limited financial resources.* Inevitably, this means that some potentially commercial projects are deferred until they rise to the top of the portfolio.

Changes in the outlook for oil and gas prices will influence corporate cash flows and hence the likely profile of development capital spending. It is the capturing of "intent to develop" that prevents companies from mechanistically deriving their reserves disclosures from a single automated system.

CHOOSING THE RIGHT OIL AND GAS PRICE

One of the conclusions of the CERA February 2005 Special Report was that the use of year-end prices was hard to justify in light of the volatility of oil and gas prices in markets around the world. This volatility can lead to the anomaly whereby two equal partners in the same project could report radically different reserves and SMOGs just by virtue of choosing different financial year ends.

*The higher returns that can be derived from such an approach were researched in the CERA Private Report *Daring to Be Disciplined: Continuous Portfolio Improvement*, which examined the paradox whereby the companies with the greatest capital resources treated capital as if it were a scarce commodity, while those with the smallest capital resources treated capital as if it were effectively an infinite resource.

THE IMPACT OF DIFFERENT YEAR ENDS: THE TALE OF CASTOR AND POLLUX

In January 2005, over 2 billion barrels of proved reserves were debooked, or had their new bookings deferred, by Canadian bitumen producers who employ in-situ (cyclic steam or steam-assisted gravity drainage) production techniques. This was the result of the confluence of several factors, the most significant of which was the dramatic widening of spreads between the prices of the produced streams and West Texas Intermediate (WTI) while WTI was making a rapid retreat from then-record levels above $50 per barrel. Other contributing factors were the high costs of condensate diluent and natural gas. By the end of January, prices and spreads had moved to a point at which most of the debooked volumes could be rebooked. However, since the reserves changes will not be reflected until year-end 2005 reporting these companies will produce hundreds of thousands of barrels of bitumen in the interim from these "nonexistent" reserves. No company changed its long-term strategies or investments because of the temporary adverse economic conditions. The interests of investors were not well served by the confusion that was caused by the mechanistic approach to reducing these reserves,

To illustrate the impact of volatility in year-end prices, we considered two fictional producers of a relatively high-cost resource base—we call them Castor Inc. and Pollux Corp. They are, like the mythical figures, twins, but they are also different (see the box "Castor and Pollux: Not Really Identical Twins").

Castor and Pollux: Not Really Identical Twins

Castor and Pollux are joint 50 percent owners of a concession to produce bitumen. The production is blended to a specification at which it can be transported, and this blend typically sells for 50 percent of the price of WTI. However, the differentials vary during the year. For illustration purposes, development costs for the undeveloped portion of the concession (all of which has been technically proved to be producible by appraisal drilling) are $12.50 per barrel, over the life of the asset, and production costs are $10 per barrel of bitumen.

Out of a total producible resource base estimated at 2 billion barrels, some 500 million barrels are developed and producing (i.e., the capital costs are sunk costs), current development plans cover a further 500 million barrels, and the remaining 1 billion barrels may be developed in the future, subject to the partners' deciding to commit to their development.

Castor has a financial year end of September 30 while Pollux's financial year ends on December 31, but in all other respects they are identical companies (same overheads, etc.). Production from the currently developed area is running at 75,000 barrels per day (bd) and the incremental development will raise this to 150,000 bd for an investment of $6.25 billion over the life of the project. Annual operating costs will rise from $275 million to $550 million.

BUY CASTOR, SELL POLLUX?

If we imagine how the reserves disclosures of Castor and Pollux would have looked for their years ending in 2004, we can immediately see the problem.* Actual Cold Lake Bitumen Blend prices were approximately 50 percent of a WTI price of $49.59 at the end of September—approximately $25 per barrel—versus approximately 20 percent of a WTI price of $43.39 at the end of December—under $10 per barrel (see Figure 4-1).

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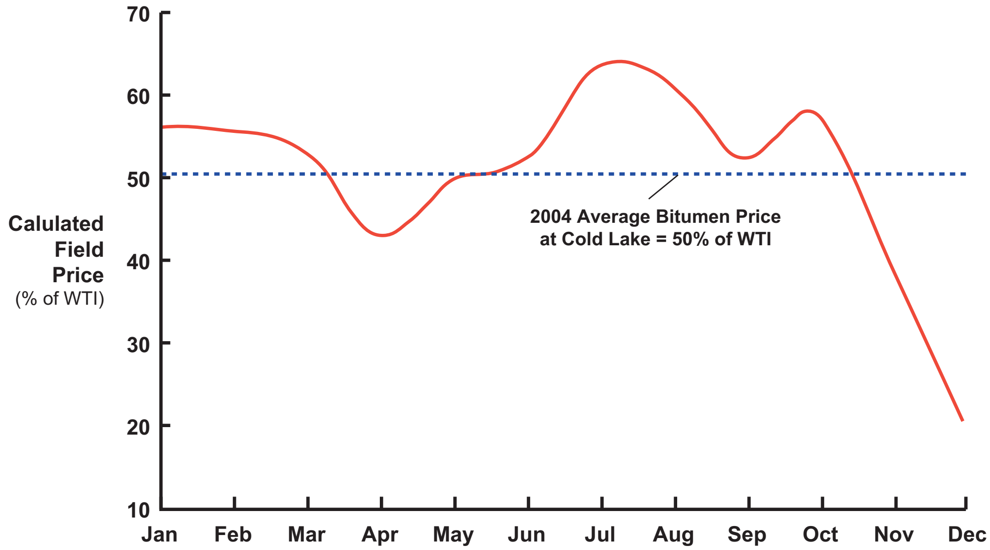
*We have treated Castor and Pollux under oil and gas reserves disclosure rules in order to illustrate the impact of the 1978 System. If these reserves were mined then the treatment of the reserves disclosures would have been different and their disclosures would have been directly comparable despite the different year ends. The greater robustness of mining disclosures in this regard makes a strong case that harmonization of the treatment of all oil sands disclosures should draw upon the strengths of this approach.

Figure 4.1

2004 Bitumen Price at Cold Lake as a Percentage of WTI (NYMEX)



Source: Cambridge Energy Research Associates.
51209-20

Castor would have reported proved developed reserves of 250 million barrels and proved undeveloped reserves of 250 million barrels.* Pollux, Castor's 50 percent coventurer in the resource, would have reported no reserves.

Had price differentials not widened so dramatically and remained at 50 percent of WTI, Pollux would have reported 250 million barrels of proved producing reserves but no undeveloped reserves, while Castor would still have reported the full 500 million barrels of proved reserves. Both entities would still have been embarking on capital investments totaling $6.25 billion, but the companies would present a very different picture of the likely success of this venture through their mandated disclosures.

Supporters of the status quo might argue that both Castor and Pollux would have explained the situation clearly in their operational reviews filed as part of their annual reports. But this neglects a growing trend among analysts, availing themselves of the newest techniques and technologies, to use electronically extracted quantitative data for screening investments. These services increasingly lose the rich qualitative data provided in management discussion of results and future plans. This could lead to Pollux's appearing less attractive than Castor among a universe of potential investment candidates—simply because they had a different financial year end. This was not the intent of the 1978 System.

*We have ignored the effect of royalties for simplicity.

A POSSIBLE IMPROVEMENT TO THE SYSTEM

Volatility of results from one year to another, however, does not reflect the longer-term nature of company investment decisions, Most observers of the E&P industry consider that the use of average prices—perhaps annual average—would eliminate much of the volatility. Major oil company portfolios are increasingly characterized by long lead time, high capital expenditure projects and therefore long-term price averages are preferred. However, this may not be suitable for the independents, many of which hold portfolios constructed of smaller projects with shorter payback times. In this case an annual average price might be more appropriate. It is not possible to develop a perfect solution for all. However, it is generally agreed that a 12-month average is preferable to the currently mandated year-end price.

It is rare for year-end prices, or other historical adjustments to price for transportation, gravity, and other factors, to be the same as the annual average price for oil and even more so for gas (where in the Northern Hemisphere natural gas prices tend to be seasonally higher at the end of December than for the year as a whole).

The use of prices (and adjustments to price for transportation, gravity, and other factors) that were indicative of those prevailing in the previous 12 months would eliminate much of the volatility and provide a more robust, stable measure of reserves and SMOG. In relation to oil sands specifically, the Canadian Association of Petroleum Producers has submitted a recommendation to the SEC that costs of production (including natural gas feedstock and diluent) should be averaged over a one-year period to remove seasonal anomalies. In addition, they have proposed that margins for blended crude streams versus marker prices (crude price differentials) should also be averaged over a one-year period. This would be consistent with the SPE approach as it is currently drawn and, furthermore, reinforces the view expressed in the next chapter: that the long-term forward economics of oil sands production are robust, regardless of short-term spikes or troughs in project profitability.

CONCLUSION

Participants in the E&P industry, from the perspective of many different stakeholders, generally agree that allowing the price, and other adjustments, for reserves calculations to be based on figures representative of those for a 12-month period is preferable to the currently mandated year-end price, as it removes "point in time" variability, reduces the extent of year-on-year changes, and avoids seasonal price distortions. On this basis CERA recommends the use of a 12-month average price.

CHAPTER 5: THE INCREASING ROLE OF NONTRADITIONAL RESOURCES

INTRODUCTION

In Chapter 2 we refer to the "widening" of the definition of what constitutes oil. This widening reflects the growing contribution from extra heavy oils, ultradeep water production, gas-to-liquids (GTL), coal-to-liquids, biofuels, and the like. This chapter focuses on two of these nontraditional resources: extra heavy oil that typically requires some upgrading and GTL. Together they may account for nearly 6 million barrels per day (mbd) of liquids production by 2015, a significant increment of total world supplies. Furthermore, when combined with gas-related liquids (natural gas liquids and condensate) and ultradeepwater oil production, by 2015 such liquids may account for more than a third of global liquids supply capacity.

Some nontraditional resources present challenges to current reserves disclosure regimes. The 1978 System has not been updated to reflect the impact of these new sources of production, nor is it well placed to provide guidance on determining the boundary between upstream and downstream in a consistent manner. However, the SPE Oil and Gas Reserves Committee has set itself the task of drafting consistent and universally applicable definitions to incorporate nontraditional resources that will keep up with the growing array of development schema. By contrast, Regulation S-X specifically excludes mineable oil sands from the definition of what constitutes oil and gas (despite the choice of development scheme often being influenced by economic considerations).* This is another example of a distinction that seemed sensible almost three decades ago being overtaken by the ingenuity and innovation of the industry.

NONTRADITIONAL RESOURCES IN CONTEXT

It is generally accepted that Saudi Arabia contains the largest resources of conventional oil in the world. But both Canada and Venezuela contain vast resources of extra heavy oil that have become commercially viable because of advances in technology and increases in oil prices. The Venezuelan government has recently claimed "reserves" of 235 billion barrels of extra heavy oil in the Orinoco in addition to 80 billion barrels of conventional oil. Official figures for Canadian reserves from the oil sands are based on an assessment of what proportion of the estimated 2.2 trillion barrels in place are recoverable. The *Oil and Gas Journal* cites a recoverable figure of 175 billion barrels.** By some measures, either of these deposits can be reasonably compared with Saudi Arabia's current reserve base.

The world's natural gas reserves are approximately the same in energy-equivalent terms as the conventional oil reserves; the economics of GTL conversion have become sufficiently attractive that the process is moving from the fringes into the mainstream of E&P company strategies, ranging from the majors to a few specialist independents.

The US Department of Energy estimates that the costs of oil shale production will fall from a current level of $45 per barrel breakeven to as low as $30 per barrel in the coming years.*** If production from oil shale emerges as a viable resource after many years of study and research, it would become another major source of nontraditional oil.

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*Regulation S-X covers a wide range of activities, but specifically Reg. § 210.4-10 "prescribes financial accounting and reporting standards for registrants engaged in oil- and gas-producing activities in filings under the federal securities laws and for the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States."

**Source: Alberta Energy Utilities Board, April 17, 2002, *Alberta's Oil Sands—A Sleeping Giant Awakens*.

***Source: US Department of Energy Web site: http://www.energy.gov/.

Completing the set of what we call the nontraditional resources, coal-to-liquids conversion has also become economically viable in recent years. Global coal reserves are larger still than either conventional oil or gas reserves. This has moved such projects from the historical obscurity of Germany's fuels effort during World War II and South Africa's sanction-driven necessity into mainstream planning today in parts of China.

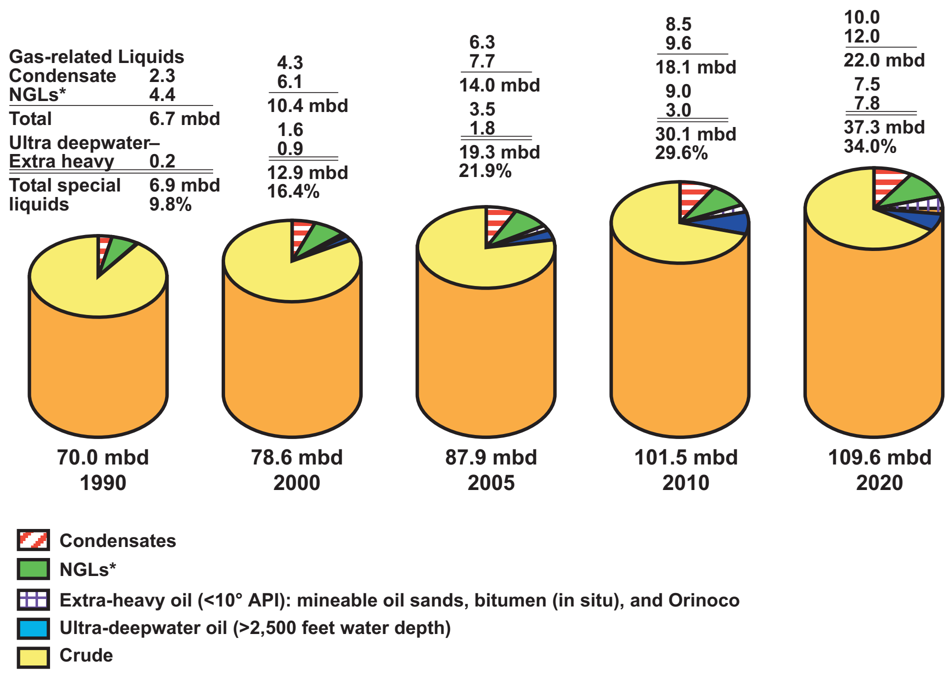
As we have already observed, all of this combines to present a possible future in which such resources, when added to ultradeepwater crude production and gas-related liquids, could account for more than a third of global liquids capacity in 2015 (see Figure 5-1).

FROM THE FRINGES TO CENTER STAGE

When the 1978 System was created, nontraditional resources accounted for an insignificantly small proportion of global activity (and even less of SEC registrant activity). Hence, it is likely that issues associated with such production, beyond the specific exclusion of mined oil sands in Regulation S-X, did not figure heavily in the minds either of Congress in creating the 1975 mandate through the Energy Policy and Conservation Act or of the SEC and those they consulted in drawing up the regulations.

Figure 5.1

Special Liquid Components of World Production Capacity



Source: Cambridge Energy Research Associates.
*Includes LPG (propane and butane), ethane, and natural gasoline derived from processing natural gas.
Updated January 2005.
40916-30

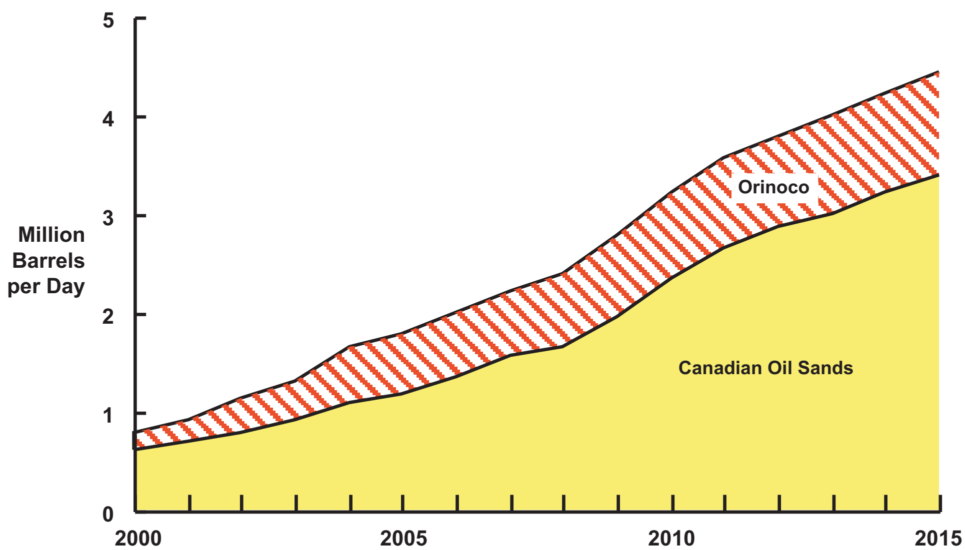
The potential of the oil sands in Alberta was recognized, but prices of conventional light, sweet crudes, such as Brent and WTI (although not yet traded on liquid commodity exchanges) had not risen to a sustained level that justified large-scale investment in this resource. This was less a function of the prospective economics of extraction—oil prices were expected to continue rising—than of the availability of more attractive investment opportunities such as in the North Sea, non-OPEC Middle East, and elsewhere.

What oil was produced from the oil sands entered the oil markets via refineries configured to process the output. Canadian producers sought to innovate in order to maximize the commercial value of their production streams. In many cases they began to integrate their projects with upgraders to produce Syncrude.* The range of technologies used soon increased and the range of project anatomies multiplied. As Venezuela began to develop its Orinoco resources, it sold its production as Orimulsion™—a fuel oil substitute created out of an emulsion of heavy oil and water. It was not until the full-scale opening to international investment that Venezuela entered the Syncrude market.

CERA's forecast for the aggregate Canadian oil sands and Venezuelan extra heavy oil production is some 3.0 mbd by 2010, rising to 4.9 mbd in 2015 (see Figure 5-2). The current publicly traded owners of projects expected to yield these volumes are SEC registrants, and the associated reserves will become a significant component of their reserve bases.

Figure 5.2

Heavy Oil Production Forecast



Source: Cambridge Energy Research Associates.
51209-22

*Syncrude is an oil industry term to describe synthetic crude oil, normally created by breaking down the long-chain hydrocarbon molecules in heavy oil into more valuable, lighter crude oil.

CANADIAN OIL SANDS

CERA believes that Canadian oil sands production will enter the mainstream and, once developed, will remain a growing component of North American production and remaining reserves. Recognizing these reserves and providing transparent disclosure will become increasingly necessary as volumes increase. Currently, there are a number of oil sands projects either in production, in the development phase, or in planning. Most new projects include some form of upgrading, either as a separate downstream component of the project or integrated into the overall development plan. Appendix C lists proposed projects and provides more details on a few of the existing and "under way" projects in order to illustrate the growing diversity of development schema and the E&P industry's ability to innovate to bring down the breakeven costs of development and production.

There are numerous economic scenarios associated with these types of projects subject to future oil and gas prices and the potential to capture these volumes as reserves is not a single path. Recognizing these reserves and providing transparent disclosure will become increasingly necessary as volumes increase.

As technologies mature, progressively thinner bitumen beds will become accessible, extending the plateaus of existing developments. This serves to illustrate an important factor concerning oil sands production: production rates do not normally decline during the life of the project. In fact, production from any phase of a project tends to increase slightly as a result of process optimization. The inherent economies of scale encourage expansion phases to be added over time. This is in stark contrast to conventional oil fields that typically decline by between 5 and 25 percent after their initial production plateau.

The components of cost in producing oil sands vary depending on whether an in-situ (steam-assisted gravity drainage [SAGD] or cyclic steam injection) process or surface mining is used. CERA's analysis suggests that the total costs for upgraded Syncrude from a mined oil sands project lie in the $20–$25 per barrel range depending on what assumptions are made for the cost of capital, the price of natural gas consumed, and fabrication costs. The dramatic increase in activity illustrated by the list of planned projects in Appendix C has given rise to some increases in costs. However, with oil prices at current levels, it is not hard to see why investment in upgraded crude activities may be an attractive investment.

Our analysis of in-situ production based on SAGD or cyclic steam injection yields total costs in the $13–$15 range before upgrading. The cost of upgrading are estimated at a further $10 per barrel, bringing the range up to that of mined production, although the cost structure is such that the marginal operating cost is lower for in-situ than for mined production. The decision to upgrade depends on the perception of the margin between the value of raw bitumen blended with condensate (to allow it to be transported) and the value of upgraded synthetic crude.

Regardless of which development route is pursued, oil sands production has moved from being a minor fringe activity to a major North American oil source for the years ahead.

VENEZUELA: ORINOCO HEAVY OIL BELT

Until the development of the Orinoco heavy oil belt became a significant component of Venezuelan production, this resource had not figured prominently in the global oil markets. The development of four megaprojects undertaken by the international majors brought these resources to center stage. Appendix C also outlines the characteristics of each of these projects, which serves to demonstrate their scale and complexity.

The pre-"government take" economics of Orinoco heavy oil developments are robust. However, CERA forecasts that the potential growth available has receded in the short term as international oil companies consider whether the political and fiscal risks crystallizing in Venezuela today are acceptable. Despite these risks, in the longer term, there is a good chance that activity will increase, with more projects undertaken and significant production delivered. Indeed, a number of additional blocks in the Orinoco have been licensed to national oil companies, including Petrobras, China National Petroleum Corporation, Iran's PetroPars, India's Oil and Natural Gas Corporation, Gazprom, and Lukoil.

The production from the Orinoco is developed like conventional oil and gas activity by the operators—production through oil wells into a processing plant—and appears to present no specific problem under the current rules.

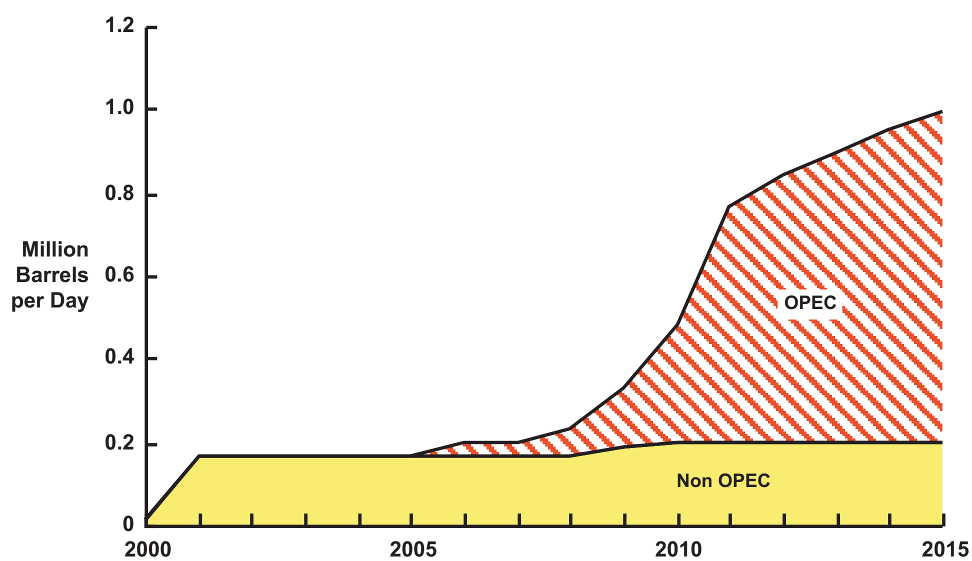
GAS-TO-LIQUIDS PROJECTS

Current volumes of GTL are relatively small but could grow to nearly 400,000 bd by 2010 and more than double that number by 2015 if currently delayed projects do proceed. The economics of GTL are less competitive than for oil sands in the current environment. Nonetheless, research and development has allowed pilot-scale plants to operate successfully, and companies are now prepared to back their judgment with commercial-scale plants that entail significant investment.

Figure 5-3 illustrates CERA's forecast of the likely production profile from commercial-scale plants. GTL projects are often seen as alternatives to liquefied natural gas (LNG) projects for commercializing gas reserves. Indeed the biggest obstacle for a commercial-scale GTL project is the perception that the netback—the value of the feed gas calculated as the margin between costs and revenues—to the gas production is higher under an LNG development, which accounts for the delays of several planned projects.

Figure 5.3

Gas-to-liquids Forecast



Source: Cambridge Energy Research Associates.
51209-23

These delays need not be permanent. One argument in favor of GTL is that the netback value of the gas feedstock is exposed to a different set of risks than LNG, and such projects therefore provide a degree of price risk diversification. The growth in the demand for middle distillates at a time when refining capacity is tight and marginal crude oil production is heavy or sour, requiring complex refineries to upgrade it, results in attractive GTL project economics. Improvements in technology and operational processes have brought GTL costs down into their current range. Yet they are under upward pressure because of tightness in the market for engineering and construction services particularly and oilfield supply costs generally.

The technical and commercial arrangements surrounding GTL developments have not yet exposed shortcomings in the current rules. However, as technologies and markets mature, reserves disclosure regulations may require flexibility to deal with issues that, for the time being, remain unforeseen.

CONCLUSION

Significant volumes of nontraditional resources, including mined oil sands, are expected to enter the global oil and gas markets over the coming years. The current SEC regulations—the 1978 System—do not properly cater to all of these volumes. Through the exclusion of mined oil sands mandated under Regulation S-X, the current reserves disclosures do not adequately provide forward visibility for likely future levels of oil supply capacity at a time when anxiety about the sufficiency of these supplies is heightened. Inclusion of all oil sands production and reserves is a priority in order to remove this distortion from the reporting model. The central recommendation that the SEC adopt the SPE definitions and guidelines and delegate the task of keeping them updated to the SPE Oil and Gas Reserves Committee is consistent in this regard.

We have demonstrated that activities that were once on the fringe of the supply mix are now entering the mainstream and that many billions of dollars are being invested in bringing these volumes to market. Continuing ambiguity about the treatment of such volumes does not serve any stakeholder. Passing responsibility to the SPE is an essential first step toward the open, transparent dialogue that will be required to develop a robust answer to the questions being asked of the disclosure rules by these new sources of supply.

APPENDIX A

KEY QUESTION

The key question in this case is what is meant by "information" and what can be *known* with *reasonable certainty*. The current US Securities and Exchange Commission (SEC) reserves definitions state:

> In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

This wording leaves open the possibility that if a method or technique provided reasonably certain *information* of the lower boundary of a hydrocarbon-bearing zone, below the direct sampling provided by wellbore penetration, then the lower boundary could be used to define a volume of proved reserves.

The facts and data presented in this case make the argument that, under certain conditions, the technique known as the pressure gradient method provides reasonable certainty of the depth of an oil/water contact in a producing reservoir.

DESCRIPTION OF TECHNIQUE

The basic principle of the technique has been known for many years. Simply, if there are two fluids in a column, the pressure increases the deeper one measures in the column. At the point where the two fluids meet, the pressure is equal. However, given the different densities of two fluids (i.e., oil and water), the pressure change of the two fluids at depth will increase at different rates. In plain speak, 100 linear feet of water weighs more than 100 linear feet of oil. Thus, by making several pressure measurements at different depths in both fluids, one can "triangulate" the depth of the oil-water contact. See Figure TK for an illustration of pressure versus depth measurements plotted and the oil-water contact interpolated.

PUBLICATIONS

Articles describing and debating the technique and its component technologies have appeared in *World Oil,* the *Journal of Petroleum Technology,* and the *Oil and Gas Journal*.

PEER REVIEW

This technique has been discussed in peer reviewed articles published by the SPE in the following instances:

- July 1967, SPE paper no. 1303: "Estimating Gas-Water Contacts in Aquifer Gas Storage Fields Using Shut-In Wellhead Pressures," P. Burnett, R. Ryan.

- March 2000, SPE paper no. 59696: "Precision Pressure Measurement: The Key to Accurate Fluid-Interface Monitoring," P. M. Hannah, K. L. Vekved.

- June 2001, SPE paper no. 71566: "Multiple Factors That Influence Wireline Formation Tester Pressure Measurements and Fluid Contacts Estimates," Mark A. Proett, Wilson C. Chin, Mohan Manohar, Richard Sigal, Jianghui Wu.

PUBLISHED GUIDANCE

In textbooks, technical papers, and internal documents developed by E&P firms, guidance is provided on the application and suitability of the pressure gradient method for determination of fluid contacts. Below is an extract from the textbook *Estimation and Classification of Reserves of Crude Oil, Natural Gas and Condensate,* by Chapman Cronquist, published by the Society of Petroleum Engineers press (ISBN 1-55563-090-1):

> It is suggested that, for each data set—oil and water—there should be at least four valid data points, and the regression coefficient, r^2, for each LSF should be at least 0.95. The range of LSF-calculated pressure gradients—at 80% confidence—should be in reasonable agreement with the pressure gradients determined from PVT or other data.

Further guidance is available (Dake 1994) concerning the effects of mud cake on pressure readings, the reduced suitability of the technique in regions exhibiting complex stratigraphy or faulting, and requirements for proving reservoir communication.

EXAMPLE OF PRACTICAL APPLICATION

Figures A-1 through A-5 illustrate a situation in which the pressure gradient method was used to determine the reserves of a significant field in the late 1990s. Robert Rasor of H.J. Gruy and Associates generously provided the illustrations.

Case Outline

In an onshore international location operated by a US-based independent, a significant oil field was discovered. At the time of this discovery, limited well penetrations existed; however, a large amount of reservoir data (e.g., logs, pressure readings, core samples) was collected during the delineation phase of the project.

Figures A-3, A-4, and A-5 present a structural map outlining the overall shape and configuration of the field, as well as a representation of the log response of the strongly delineated layers and a schematic illustrating the well penetrations and zones where pressure measurements were made using drillstem tests (DSTs).

Multiple pressure measurements were made in both the penetrated oil and water zones. Plots A-4 and A-5 show the pressure measurements and interpolated oil-water contact for reservoirs MA and G, the first and third when viewing schematic A-3 from left to right.

Given the high number of pressure measurements and data confirming connectivity between the measuring wells, the operator expressed high confidence in the calculated depth of the oil-water contact. Reserves estimates were then calculated using both a strict wellbore penetration standard of lowest known hydrocarbon and a lowest known hydrocarbon determined from pressure gradient data. The current SEC interpretation (constrained to penetrated depth of hydrocarbons, or lowest known hydrocarbons) yielded a proved reserves estimate of 261 million barrels. The use of the information gathered from the pressure gradient method yielded an estimate of proved reserves of 658 million barrels.

Later well penetrations confirmed the depth of the fluid contact.

Figure A-1

Structure Map

Reservoir MA

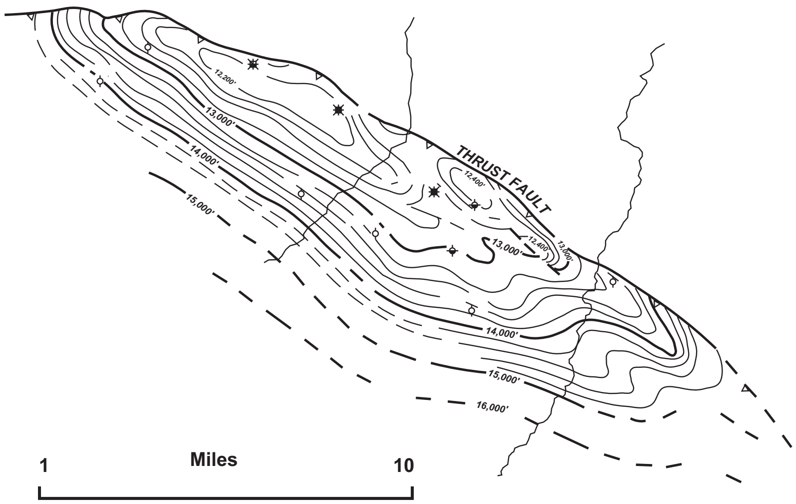
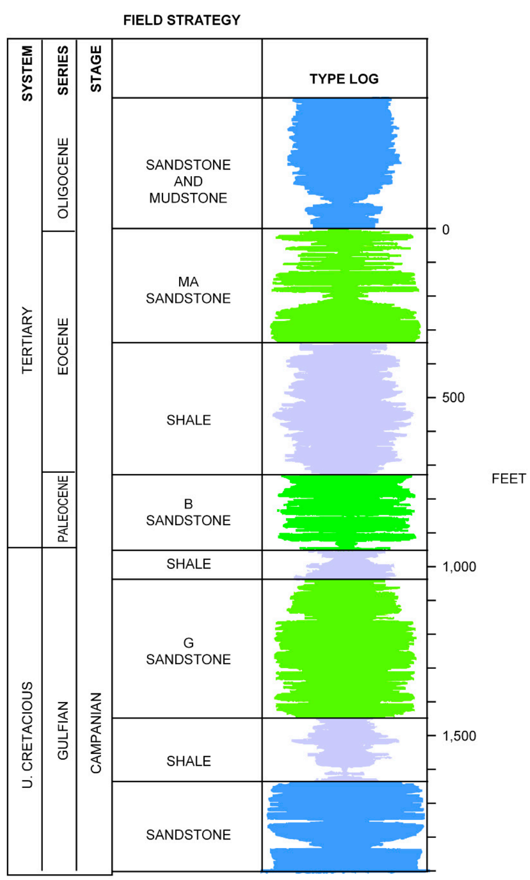


Figure A-2

Type Log

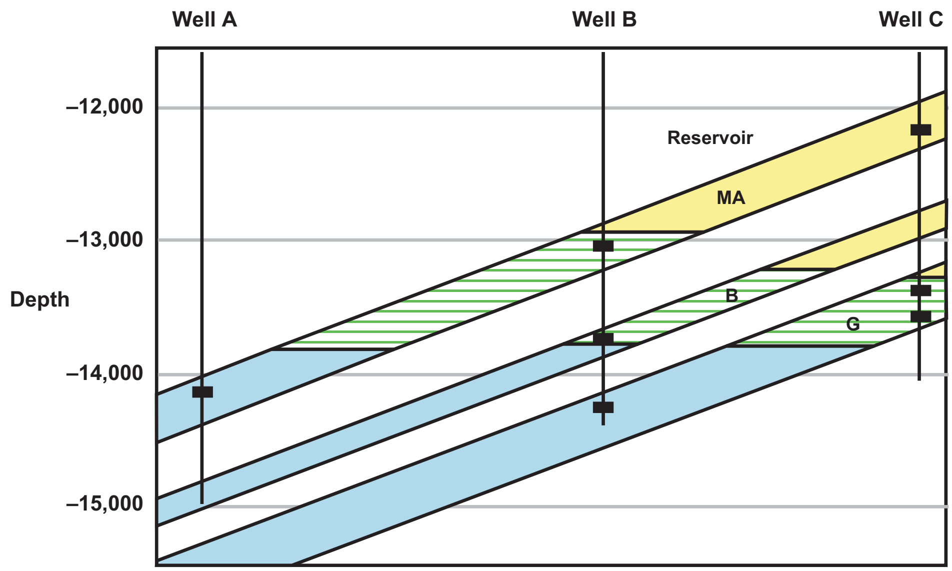


Source: H.J. Gruy and Associates, Inc.
51209-16

Figure A-3

Field

Schematic Cross-section with Fluid Contacts and DSTs

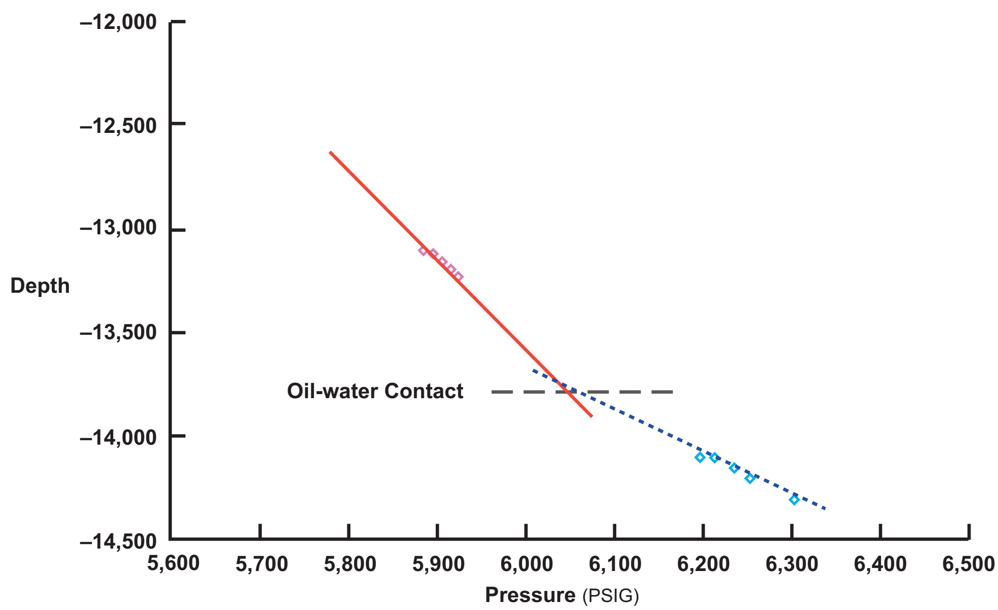


Source: H.J. Gruy and Associates.
51209-17

Figure A-4

Reservoir MA

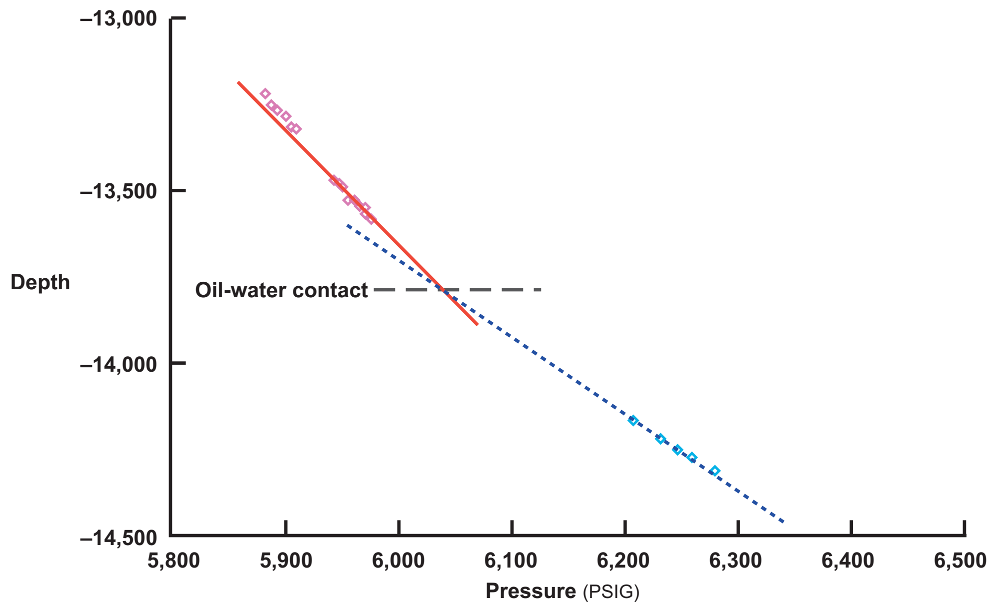
Fluid Gradients



Source: H.J. Gruy and Associates.
51209-18

Figure A-5

Reservoir G
Fluid Gradients



Source: H.J. Gruy and Associates, Inc.
51209-19

APPENDIX B

RESTRUCTURING OPTIONS CONSIDERED

In our analysis, CERA considered the following restructuring options:

- **An external entity that is part of, or modeled on, the Financial Accounting Standards Board (FASB)**. The appeal of this option is that it is based upon a proven model. However, there is little indication that the FASB is interested in taking on the reserves issue at this time. Moreover, the FASB does not possess the engineering knowledge and expertise required to modernize the guidelines. The other option—the creation of a new, reserves-specific body modeled on the FASB that would largely replicate the activities of the SPE Oil and Gas Reserves Committee—would require strong support from the US Securities and Exchange Commission (SEC), Congress, and the industry. However, there does not seem to be support from any constituency for this option.

- **A fully staffed group within the SEC.** The SEC could certainly form and staff a separate group within the commission and charge it with the responsibilities of rule modernization and fostering public debate on the guidelines. Yet, there are several practical considerations that may limit the appeal of such an option. Given the apparent lack of SEC or Congressional desire to push (and fund) such an initiative, it is difficult to imagine such an option being embraced. Furthermore, it appears to CERA that the industry's confidence in this kind of internal approach has been eroded by its experience of the current combination of rule making and compliance functions and the complexity of the tasks involved.

  One lesson gleaned from the experiences of the SPE and the FASB is that execution of rule making and guideline drafting in a professional and timely manner requires access to a broad and deep resource of technical expertise. Few individuals can be expected to be expert in topics as diverse as geology, geophysics, reservoir engineering, facilities engineering, statistics, contract law, and economics, to name a few of disciplines covered in recent definition debates. The dynamic nature of the challenges of the industry should be reflected in the makeup of those assessing and recommending modifications to the regulations. Based upon the experiences of the Society of Petroleum Engineers (SPE) Oil and Gas Reserves Committee, such a group might need to draw upon the expertise of many specialists covering several separate domains. With a shifting roster of issues and continuing innovation by the industry, doubts would be raised about the ability of an internal group to remain current over time.

- **Use of technical experts identified by the professional societies.** The SPE has previously offered (and it is CERA's belief that other professional societies would be prepared to make the same offer) to identify the most appropriate experts from its database of oil and gas professionals to address any specific matter. Such experts might be independent consultants or employed in registrant companies. The professional societies are possibly best placed to identify respected leaders in these technical spheres. It may be that the SEC would prefer to appoint consultants rather than rely upon employees of registrants, but this runs the risk that the results might not provide the same balance as would the outcome of discussions by a group consisting of a wide cross-section of practitioners. Furthermore, the resource constraints applying to the two previous options would also apply here.

- **A subcommittee of one of the professional societies.** Under this option, the obvious home for such a body would be the SPE. In fact, an appropriate body already exists in the SPE's Oil and Gas Reserves Committee. This option would provide ready access to a broad array of technical resources from a variety of stakeholders. The strengths of the professional societies include their independence and concentration on technical issues and their collaboration with academic institutions. The value of this independence seems to have been recognized recently with the Russian government's apparent adoption of the United Nations Framework Classification, which is itself consistent with the SPE definitions for oil and gas reserves.

APPENDIX C

CANADIAN OIL SANDS PROJECTS—UPGRADERS, PROPOSED PROJECTS AND EXISTING PROJECT EXAMPLES

Table C-1

Bitumen Upgraders in Alberta

	Volume (bpd)	Comment
Suncor	277,000	Existing
Syncrude	301,000	Existing
Husky-Lloydminster	77,000	Existing
Albian-Scotford	155,000	Existing
Suncor	235,000	Expansion (Firebag and Steepbank)
Syncrude	180,000	Phased expansion
Husky-Lloydminster	5,000	Expansion
Albian-Scotford	150,000	Expansion w/plans for a total of 500,000 bpd
Nexen/Opti-Long Lake	70,000	New
CNRL-Horizon	233,000	New-only phases 1 to 3
SynEnCo-Northern Lights	100,000	New with 2 phased expansion
BA Energy-Heartland	226,000	New-first phase 75,500 bpd. 3 phased expansion
Petro-Canada/UTS-Fort Hills	50,000	New
Petro-Canada	135,000	Change refinery to upgrader/refinery
Northwest Upgrading	150,000	New with 3-phased expansion
TOTAL	2,344,000	

Source: Canadian Association of Petroleum Producers.

Table C-2

Alberta Oilsands Projects
Currently listed by Alberta Energy Utilities Board 1/24/06

In some cases, data has been updated to reflect participant input. However, not all EVB data had been verified

Company Name	Project Description	Cost in Millions	Construction Schedule	Remarks
Albian Sands Energy, Inc.	Jackpine Mine—Mining and Extraction Facility phase 1	$2,000.00		Proposed. Approved February 2004. Phase 1 will follow Muskeg R and Scotford expansions. Includes 170 MW power plant.
Albian Sands Energy Inc.	Muskeg River Mine Expansion	$2,500.00		Proposed for 2006–2009. Application filed April 2005.
BA Energy Inc.	Alberta Heartland Bitumen Upgrader Phase 1	$800.00	2005–2007	Under construction. Phased development. Jacobs Canada / Larsen & Toubro. Approved July 2005.
BlackRock Ventures Inc.	Orion Heavy Oil SAGD Facility (Phases 1 and 2)	$340.00	2005–2010	Under construction. Approved October 2004. Phased development, building to 20,000 bd.
Canadian Natural Resources Ltd.	Primrose North Cyclic Steam Stimulation (CSS) Project	$250.00	2004–2007	Under construction.
Canadian Natural Resources Ltd.	Project Horizon Mining and Drilling Project phase 3	$1,400.00		Proposed for 2009–2012. Approved January 2004.
Canadian Natural Resources Ltd.	Primrose East Cyclic Steam Stimulation (CSS) Project	$600.00		Proposed for 2007–2008. Includes 85 MW cogen plant. Application to be filed January 2006.
Canadian Natural Resources Ltd.	Project Horizon Mining and Drilling Project phase 2	$1,700.00		Proposed for 2006–2009. Approved January 2004.
Canadian Natural Resources Ltd.	Project Horizon Mining and Drilling Project phase 1	$6,800.00	2005–2008	Under construction. SNC-Lavalin / Snamprogetti Canada Inc. EPC Froth Teatment Plant SNC-Lavalin.
Connacher Oil and Gas	Great Divide SAGD Pilot Plant	$150.00		Proposed for 2006
ConocoPhillips Canada/ Total/ Devon Energy	Surmont SAGD Bitumen Commercial Project	$1,400.00	2004–2013	Under construction. Phase 1 (2004–2006).
Devon Canada Corp.	Jackfish 2 (J2) SAGD PROJECT	$500.00		Proposed for 2008–2009. Planned facility construction start third quarter 2008. Decision mid-2006.
Devon Canada Corp.	Jackfish SAGD Oilsands Project Phase 1	$450.00	2005–2007	Under construction. Approved December 2004.

Table C-2

Alberta Oilsands Projects (continued)

Company Name	Project Description	Cost in Millions	Construction Schedule	Remarks
EnCana Corporation	Foster Creek Commercial Thermal Recovery Project Phase 1C	$330	2004-2006	Nearing completion.
EnCana Corporation	Foster Creek Commercial Thermal Recovery Project Phase 1D/E	$740	2006–2010	Nearing approval.
EnCana Corporation	Foster Creek Commercial Thermal Recovery Project future phases	$370	2004-2006	Engineering phase
EnCana Corporation	Christina Lake Commercial Thermal Recovery Project future phases	$1,100	2005-2012	Initial phase under construction, other phases in engineering.
Husky Energy Inc.	Tucker Lake SAGD Project	$500.00	2005–2006	Under construction. Approved July 2004. Nordic Acres Engineering (FEED). SNC-Lavalin / PCL Industrial Management (Central Plant).
Husky Energy Inc.	Sunrise Thermal Project Phases 2 to 4	$1,900.00		Proposed for 2009 onwards.
Husky Energy Inc.	Sunrise Thermal Project SAGD Oilsands Project Phase 1 (Kearl Lease 187)	$800.00		Proposed for 2006–2008. Planned production 2007–2008. Application approved.
Imperial Oil Resources	Extension of Phases 9 & 10 Mahihkan North	$350.00	2005–2006	Under construction. Approved February 2004.
Imperial Oil Resources	Nabiye	$5,300.00		Proposed. Includes wells, field facilities and a plant to generate steam, process bitumen and treat water. Regulatory approval obtained in Febuary 2004.
Imperial Oil Resources/ ExxonMobil Canada	Kearl Lake Oilsands Mine (Kearl Lease 187)	$6,500.00		Proposed for 2007–2010, pending approvals. Phased development. Application for regulatory approval filed.
Japan Canada Oil Sands Limited (JACOS)	Hangingstone SAGD Commercial Production Project	$450.00		Proposed. Two phases. Planned construction start 2006.
North West Upgrading Inc.	Bitumen Upgrader Phase 1	$1,300.00		Proposed. Planned construction 2007–2009, pending approvals. Application to be filed in 2005.

Table C-2

Alberta Oilsands Projects (continued)

Company Name	Project Description	Cost in Millions	Construction Schedule	Remarks
OPTI Canada Inc./ Nexen Inc.	Long Lake SAGD Heavy Oil Project Phase 1	$3,482.00	2004–2007	Under construction. Flint Infrastructures Ltd., Ledcor Projects Inc., Colt Engineering, Fluor. Approved Aug 2003. Upgrader, co-gen facility (370 MW) and upgrader capacity.
Pacific Energy Partners	New Oilsands Output Terminal	$4.00		Proposed
Petro-Canada	MACKAY RIVER SAGD EXPANSION	$810.00		Proposed. Application filed December 2005.
Petro-Canada/ UTS Energy Corp.	Bitmin Bitumen Extraction Demonstration Plant	$37.00	2005	Completed. SNC-Lavalin, preliminary engineering Fluor Canada. Application filed.
Petro-Canada/ UTS Energy Corp./ Teck Cominco	Fort Hills Oilsands Project	$2,000.00		Proposed for 2006–2010. Planned construction start mid-2006, production start in 2011.
Petro-Canada Oil and Gas	Strathcona Refinery Conversion to Upgrade Bitumen	$1,600.00	2004–2008	Under construction. Approved. Kellogg Brown Root/SNC Lavalin.
Petro-Canada Oil and Gas/ Nexen Inc.	Meadow Creek SAGD Bitumen Production	$800.00		Proposed. Application under review. Project includes 330 MW co-gen plant.
Suncor Energy Inc.	Firebag In-situ Bitumen Recovery Project phases 1 and 2	$1,100.00	2003–2005	Completed. Cost includes expansion of Suncor upgrader. Jacobs Engineering, Flint Energy Services.
Suncor Energy Inc.	Voyageur Oil Sands Facility Expansion (Third Oil Sands Upgrader)	$5,900.00		Proposed for 2007–2010. Applications filed March 2005. Preliminary cost estimate. Project does not include bitumen feed to upgrader.
Suncor Energy Inc.	Steepbank Mine Extension	$350.00		Proposed for 2007–2010. Application filed.
Suncor Energy Inc.	Upgrader Expansion	$2,100.00		Proposed for 2005–2007. Approved March 2004. Corporate approval announced.
Suncor Energy Inc.	New Bitumen Production Facilities at Firebag Site	$1,000.00		Proposed for 2005–2007. Approved March 2004.
Suncor Energy Inc.	Petroleum Coke Gasifier for Voyageur Upgrader	$600.00		Proposed. Included with application for Voyageur upgrader March 2005. Cost estimate preliminary.

Table C-2

Alberta Oilsands Projects (continued)

Company Name	Project Description	Cost in Millions	Construction Schedule	Remarks
Syncrude Canada Ltd.	Phase 3: Upgrader Expansion phase 1 / Aurora Mine Train 2	$6,000.00	2001–2006	Completed. Stage 1 includes two additional trains at Aurora Mine. Approval October, 1999. Expansion SNC-Lavalin, Fluor Daniel; train 2 AMEC.
Syncrude Canada Ltd.	Continuous Improvement	$1,500.00	1997–2007	Underway
Syncrude Canada Ltd.	Phase 4: Upgrader Expansion Phase 2 / Aurora Mine Train 3	$2,300.00		Proposed. Pre-engineering study underway (AMEC). Expansion SNC-Lavalin, Fluor Daniel. Train 3 AMEC.
Syncrude Canada Ltd.	Sulphur Emission Reduction Program (SERP)	$600.00		Proposed for 2005–2009. Application approved.
SynEnCo Energy Inc./ SinoCanada Petroleum Corp.	Northern Lights Bitumen Upgrader	$2,800.00		Proposed for 2008–2010.
SynEnCo Energy Inc./ SinoCanada Petroleum Corp.	Northern Lights Oilsands Mine and Extraction Plant phases 1 to 3	$2,500.00		Proposed for 2007–2008. Application to be filed by mid-2006.
Total Canada Ltd. (previously listed as Deer Creek Energy Ltd.)	Joslyn Creek SAGD Project Phase 3 and North Mine Development	$1,500.00		Proposed construction start Phase 3 in 2007, mine in 2008. Application for phase 3A filed. Application for mine in late 2005 or early 2006.
Total Canada Ltd. (previously listed as Deer Creek Energy Ltd.)	Joslyn Creek SAGD Project Phase 2	$178.00	2004–2006	Nearing completion
Whitesands In Situ Ltd.	Whitesands Experimental Pilot Project to test Toe-to-Heel Air Injection (THAI) Technology	$44.70	2004–2005	Completed. Approved February 2004.

Source: Alberta Energy Utilities Board.

CANADIAN OIL SANDS PROJECTS

The projects described in more detail below are a small selection of the projects currently producing or with development under way. It is not an exhaustive list but illustrates the range of technologies and development schema employed in the oil sands.

Suncor Project

- the original oil sands project, started up in 1967
- many operating problems in first 20+ years of operation
- major turnaround in early 1990s
- strong growth and profitability record since mid-1990s
- current production capacity: 225,000 bd
- produces a range of grades, integrated to refineries
- upgrader based on coking/hydrotreating
- plans being developed to increase total output to 300,000 bd in 2008 and to 500,000+ bd in 2012–15
- in-situ production (Firebag) likely represents a significant share of planned production growth

Syncrude Canada Ltd. Project

- start-up in 1978—governments stepped in, as costs escalated, to ensure project completion
- operating problems and high costs in first 15 years
- pioneered several key new technologies in 1990s
- strong growth record since mid-1990s
- current production capacity: 260,000 bd
- produces a single grade of synthetic crude
- all production based on surface mining
- upgrader based on coking/hydrotreating
- currently expanding to 360,000 bd by 2007
- further expansions could raise capacity to over 500,000 bd post-2012

Athabasca Oil Sands Project

- start-up in 2003
- current productive capacity: 155,000 bd of bitumen
- employs new bitumen-conditioning process
- upgrading based on residue hydrocracking technology
- all production based on surface mining
- produces two grades of synthetic crude
- upgrader integrated with Shell refinery in Scotford
- first expansion to 225,000 bd planned for 2007–08
- additional expansion to 425,000 bd based on new mine could take place 2010–12

Horizon Project

- major new mining-based project under development
- major project milestones include detailed engineering, design, and construction start in 2005, with project start-up estimated for 2008
- all production based on surface mining
- upgrading based on coking/hydrotreating
- phased project approach with 110,000 bd in 2009, rising to 232,000 bd in 2014

Cold Lake Project

- cyclic steam stimulation project with continued drilling to make full use of installed plant capacity
- commercial production project begun in 1983
- production was approximately 126,000 bd in 2004
- most production sold to US refineries (blended for transportation) with and some upgraded through Lloyminster heavy oil upgrader in Saskatchewan

Foster Creek Project

- steam-assisted gravity drainage (SAGD) project following multiyear pilot
- started commercial operations in 2001
- scalable development, building incremental capacity one step at a time; no integrated upgrader
- production was approximately 29,000 bd in 2004, with end 2006 forecast of up to 60,000 bd
- further expansions intended to raise production to 150,000 bd by 2015

Christina Lake Project

- SAGD project
- advanced pilot phase
- scalable development, building incremental capacity
- current production capacity over 5,000 bd, with a first quarter 2008 target of 18,000 bd
- further expansions intended to raise capacity to 250,000 bd in 2015

Long Lake Project

- new project based on SAGD
- expected cost of integrated project: $3.5 billion
- planned start-up in 2007, with production of 60,000 bd of 38 degrees API synthetic crude
- Orcrude™ upgrading technology with hydrocracking and gasification
- integrated project uses its own production for fuel, avoiding natural gas costs
- potential for increased volumes depends on success of initial development
- success in this project would remove the need to buy gas or diluent and reduce fresh water requirements

Other major technology breakthroughs might include controlled firefloods/in-situ combustion projects and possibly solvent injection. Some solvents/surfactants are even being developed from vegetable oil and may offer more environmentally acceptable solutions.

VENEZUELAN HEAVY OIL PROJECTS CURRENTLY IN PRODUCTION

Data based on PDVSA presentation and does not reflect any updates from individual project operators.

Petrozuata Project

- project initiated in 1994
- target production rate: 104,000 bd of upgraded oil of 21 degrees API
- final project cost: $3.1 billion
- production by blending naphtha with extra-heavy oil at reservoir level and extensive use of multiphase pumping
- first oil produced in August 1998, with synthetic crude production in December 2000
- upgrader based on delayed coking/naphtha hydrotreater
- expansion being studied

Sincor Project

- project initiated in 1995
- target production rate: 169,000 bd of upgraded oil of 32 degrees API gravity
- final project cost: $4.8 billion
- production by blending naphtha with extra-heavy oil at reservoir level and extensive use of multiphase pumping
- upgrader based on delayed coking/heat distortion temperature (HDT)//moisture holding capacity (MHC)
- first oil in November 2000, with synthetic crude production in February 2002
- expansion subject to government approval

Cerro Negro Project

- project initiated in 1994
- target production rate: 104,000 bd of upgraded oil of 16.6 degrees API gravity synthetic crude
- initial estimate and final project cost: $1.8 billion
- first oil in October 1999, with synthetic crude production in August 2001
- upgrader based on delayed coking

Hamaca Project

- project initiated in 1994
- target production rate: 180,000 bd of upgraded synthetic crude of 26 degrees API
- final project cost: $4.2 billion
- upgrader based on delayed coking/HDT/MHC
- first oil in September 2001, with synthetic crude production in September 2004
- project execution affected by December 2002 general strike ■

Source: PDVSA.

In Search of Reasonable Certainty

Oil and Gas Reserves Disclosure

A Report

by

Cambridge Energy Research Associates

February 2005

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AUTHORS

@ Daniel Yergin, Chairman, CERA@
@ David Hobbs, Director, E&P Strategy, CERA@

COAUTHORS

@ Joseph Pratt, Cullen Professor of History and Business, University of Houston @
@ Richard Ward, Director, CERA@

PROJECT ADVISORS

@ Julian West, Senior Director, CERA@
@ William Severns, Senior Director, CERA@
@ Louis Carranza, Director, CERA@
@ George Helland, Senior Consultant, CERA@

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CERA PRODUCTION TEAM

@ Carolyn Depoto, Graphic Design Specialist@
@ Kimberly Etheridge, Manager, Desktop Publishing @
@ Michael Kelly, Senior Graphics Manager @
@ Geoff Morgan, Graphic Artist@
@ Tania Richards, Senior Content Manager@
@ Josephine Roccuzzo, Senior Production Editor@
@ Linda Sanders, Content Manager@
@ Carolyn Visokay, Content Manager@
@ Anna W. Warrock, Senior Production Editor@

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55 Cambridge Parkway@
Cambridge, MA 02142, USA@
Tel: 1 617 866 5000 • Fax: 1 617 866 5900 @
www.cera.com@

For more information on this study, contact info@cera.com.@

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Occidental Petroleum
Pioneer Natural Resources
PricewaterhouseCoopers
Ryder Scott
Shearman & Sterling
TNK-BP
Total
RPS Energy
Vinson & Elkins
Wintershall

AUTHOR BIOS

DANIEL YERGIN is a highly respected authority on international politics and economics and on energy. Dr. Yergin is a Pulitzer Prize winner and @ recipient of the United States Energy Award for "lifelong achievements in energy and the promotion of international understanding." He is chairman @ of Cambridge Energy Research Associates (CERA). @

Dr. Yergin received the Pulitzer Prize for General Nonfiction for his work *The Prize: The Epic Quest for Oil, Money and Power*, which became a #1 national @ best seller and was made into an eight-hour PBS/BBC series seen by 20 million people in the United States. The book has been translated into 12 @ languages. His latest book, *The Commanding Heights: The Battle for the World Economy* has received wide attention for its analysis and narrative of @ how the "world is changing its mind about markets and government." It has been translated into 13 languages and made into a six-hour PBS/BBC @ documentary@

Dr. Yergin is a member of the US Secretary of Energy's Advisory Board and chaired the US Department of Energy's Task Force on Strategic Energy @ Research and Development. He is a member of the Board of the United States Energy Association, a member of the National Petroleum Council, @ and a member of the "Wise Men" for the International Gas Union. Dr. Yergin serves as CNBC's Global Energy Expert. He is a Trustee of the Brookings @ Institution and a member of the Committee on Studies at the Council on Foreign Relations. He is also a Director of the US-Russia Business Council, @ the Atlantic Partnership, and the New America Foundation. Dr. Yergin received his BA from Yale University and his PhD from Cambridge University, @ where he was a Marshall Scholar. @

DAVID HOBBS, CERA Director, is an expert in upstream oil and gas commercial development. He is the head of CERA's E&P Strategy Service, focusing @ on strategy development and the analysis of international activity.@

Prior to joining CERA, Mr. Hobbs had two decades of experience in the international exploration and production business, more recently as head of @ Business Development for Hardy Oil and Gas. He was also Commercial Manager with Monument Oil and Gas and a drilling engineer with British Gas. @ He has led projects in Asia, South America, North America, and the North Sea. He has led major international investment and asset commercialization @ operations; negotiated acquisition, divestment, and partnership transactions; and arranged funding. He is a principal author of the CERA Multiclient @ Study *Harnessing the Storm—Investment Challenges and the Future of the Oil Value Chain* and is the author of the CERA Private Report *Daring to Be Disciplined: Continuous Portfolio Improvement*.@

Based in Cambridge, Massachusetts, Mr. Hobbs holds a Bachelor of Science degree from Imperial College in London.@

RICHARD WARD, CERA Director, is an expert in oil and gas exploration and production (E&P) information technologies, including strategic applications, @ market advantage, and financial strategies of technology use. He is one of the leaders of CERA's Digital E&P Strategies Service. Prior to joining CERA, @ Mr. Ward was Vice President, Technology, of NetworkOil, Inc., where he was responsible for scoping, developing, and implementing the company's @ critical e-business technology systems. Formerly Mr. Ward was Vice President of Sales and Marketing for Maurer Engineering, a specialized drilling @ technology firm. He previously spent seven years with Landmark Graphics in various management roles for this major E&P software company. Mr. @ Ward has managerial experience in Latin America and Southeast Asia as well as in the United States and was Adjunct Professor of eBusiness at the @ Jones School of Management, Rice University, focusing on technology issues affecting the energy industry. He holds a BA from Rice University. @

JOSEPH PRATT is Cullen Professor of History and Business at the University of Houston. He was the chairman of the University of Houston history @ department until 2004 and is affiliated with the university's Center for Public History. Mr. Pratt is the author of *Prelude to Merger: A History of Amoco Corporation, 1973–1998* and a coauthor, with William H. Becker and William M. McClenahan Jr., of *Voice of the Marketplace: A History of the American Petroleum Industry*. He also authored *But Also Good Business: Texas Commerce Banks and the Financing of Houston and Texas, The Rise of the Corporate Commonwealth: US Business and Public Policy in the Twentieth Century, A Managerial History of Consolidated Edison of New York,* and *Offshore Pioneers: A History of Brown & Root Marine* with Ty Priest and Chris Castaneda. He is also editor of the "Oil and Regional History" series of books from Texas @ A&M University Press and *The Houston Review* of History and Culture. He holds a PhD and an MA from Johns Hopkins University and a BA from Rice @ University.@

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OVERVIEW

The 27-year-old US system for measuring and reporting oil and gas reserves is no longer keeping pace with a changing, increasingly global industry and, as a result, falls short of accurately describing industry and individual companies' reserves. Yet reserves, and their actual and anticipated changes, are a central measure of exploration and production (E&P) company performance. Proved reserves are estimates of the volume of hydrocarbons that oil and gas companies believe, based on scientific and engineering analysis, they can commercially produce with "reasonable certainty" over the years ahead. Companies expect to be judged against these predictions. Their ability to meet the expectations that they create is at the core of the relationship of trust with their stakeholders.

The basis on which proved reserves are estimated and disclosed in the United States is determined by the US Securities and Exchange Commission (SEC) under a system that was shaped in the energy maelstrom of the 1970s in response to America's feeling of vulnerability to the world oil market and future supply disruptions.

It is this system, largely unchanged since its creation, that is now in urgent need of modernization. In 1975, Congress mandated the SEC to develop a system of reserves reporting that would allow policymakers to plan for "energy security"—recognized as an increasingly important component of "national security."

The SEC, working with the Financial Accounting Standards Board and following extensive and wide-ranging consultation, issued principles and standards—the "1978 System." In the more than quarter century since the 1978 System was put in place, however, the oil and gas industry has changed in at least four fundamental ways that are central to its operations and role in the 21st century, as described below.

- The globalization of the capital markets has brought non–US-domiciled companies under the umbrella of SEC regulations. This trend has been matched in the globalization of the strategies of US domiciled companies, reducing the US share of reserves subject to the regulations (around which the 1978 System was designed) from more than 65 percent to only 17 percent of the total. This unanticipated shift has focused the industry away from US reserves and also turned the SEC into a de facto global regulator.

- Technological advances greatly extended the capabilities of the industry in ways that were not imagined during the shortage days of the 1970s. These advances are dramatically altering the ways in which companies operate, and gather and interpret the data necessary to calculate their reserves.

- Changes in what might be called the "anatomies" of projects (including heavy oil, liquefied natural gas [LNG] and gas-to-liquids [GTL], as well as a greater preponderance of large and "mega" projects in deepwater or remote locations) have made it less clear when a final investment commitment is made and have greatly increased the level of expenditure prior to this final commitment. Significant resources are also excluded from the proved reserves category.

- The commoditization and globalization of the markets for oil and gas are creating ambiguity about the need for explicit long-term agreements for the sale of production—often interpreted by the industry as a prerequisite for recognizing gas reserves in areas with no ready access to spot markets. In addition, the volatility of deregulated markets has undermined the concept of "prevailing prices."

The interpretation and application of the current regulatory regime—the "1978 System"—governing disclosure of oil and gas reserves does not accurately reflect these new realities. As a result, investors are less able to draw valid conclusions about the intrinsic value and prospects of E&P companies, and this increased uncertainty may result in higher costs of capital for the industry than would otherwise be the case. What is reported increasingly fails to convey an accurate portrait of companies' positions.

Since its inception in 1934, the SEC has developed a tradition of consultation with a wide range of informed experts. That tradition, which has been a source of strength for the SEC over many decades, should be utilized with regard to reserves disclosure to reflect the enormous changes over the past 27 years. Moreover, in recent years the requirement for recognizing proved reserves has in practice shifted from "reasonable certainty" toward "absolute certainty." In so doing, a principle-based reserve reporting system has increasingly become a rule-based one, without the kind of transparency and discussion that the SEC habitually employs elsewhere. Potential solutions to the emerging strains in the system include

- reversion to a principles-based regime with specific rules and guidance, based on transparent and wide-ranging consultation with interested parties, only where required to interpret a principle; an example of a specific rule that has been overtaken by industry developments is the use of year-end pricing for calculating reserves—this is one of the areas that is in need of most urgent attention (the 1978 System grew out of an era of regulated oil and gas prices and is ill suited in its present configuration for a world of commodity pricing for oil and gas)

- creating some separation within the SEC between those responsible for creating and modernizing the rules and those monitoring compliance to encourage a more constructive dialogue

- creating a forum for considering new issues as they arise—such as the impact of new technologies and consistency in the handling of LNG, GTL, oil sands, and other nontraditional oil and gas sources

Conclusion@

The current regulatory regime—the 1978 System—emerged first and foremost as a response to the energy crises of the 1970s and fears about the vulnerability of the United States to dependence on foreign energy sources and future disruptions. It was rooted in the technologies and market structures of the 1950s and 1960s. The significant changes in the industry since then make a compelling case for modernizing the system to create a workable, constructive framework for the oil and gas industry in the 21st century that responds to the needs of both investors and consumers and that does indeed, in a very different world, meet the test of "reasonable certainty."