Perspective

The Near-Term Energy Challenge

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Introduction: The Landscape

Energy is the most important problem facing humanity today. Nobel laureate Richard Smalley lists the top ten problems of the world as: energy, water, food, environment, poverty, terrorism/war, disease, education, democracy, and population. He argues that most of these problems can be solved if an economic, environmentally safe, sustainable energy source can be found.

Energy is also the biggest business in the world. Worldwide energy consumption in year 2001 (EIA, 2003) was 404×10^{15} BTU (~13.4×10^{12} W or ~200×10^{6} barrels of oil equivalent per day or BOE/d). By all counts, the energy demand for consumption is expected to go up significantly in the next 50 years (the near-term). World population is increasing, especially in the developing countries. It is expected to increase about 50% over the current population in the next 50 years (Skov, 2003). A significant increase in per capita income is expected in the developing countries, e.g., China. Per capita energy use increases with the human development index (Benka, 2002) and correlates with per capita income (Economides and Oligney, 2000). If we want our per capita income to increase, energy use will increase. EIA (2003) projects a 50% increase in energy demand in the next two decades over the present time. The increase over the next 50 years would be 65% to 172% assuming a net growth rate of 1% or 2% per year, respectively. This implies the energy demand level in the year 2050 to be between 900–$1{,}800\times10^{15}$ BTU/yr (30–60×10^{12} W or 450–900×10^{6} BOE/d). The near-term challenge is to meet this increased energy demand economically without significant environmental cost.

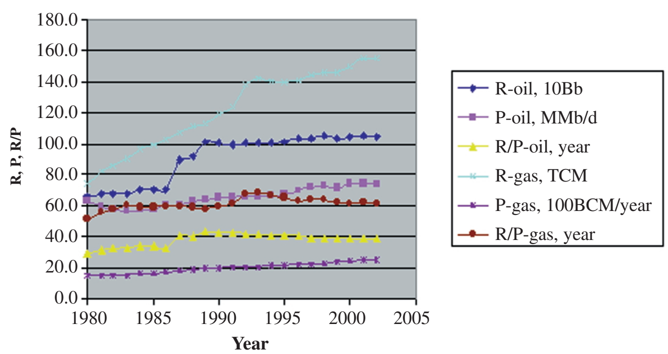

Figure 1. Historical data for reserves (R in 10 billion barrel unit for oil and in trillion cubic meter unit for gas), production (P in million barrel per day unit for oil and 100 billion cubic meter per year unit for gas), and the reserve-to-yearly-production ratio (R/P, years).

Most experts believe that the energy need in the next 20–50 years is going to be mostly met by the fossil fuel (oil, gas, and coal). In the year 2000, oil accounted for 39% of all energy; gas and coal provided for 23% and 22%, respectively. Renewable (solar, wind, hydropower, biomass, etc.) and nuclear energy sources supplied about 7% and 9%, respectively, of the total energy consumption (EIA, 2003). Electricity from solar energy costs about \$314/MWh compared to about \$41/MWh for gas (Economides et al., 2002). Concerns about the safe disposal of radioactive material are limiting the growth of nuclear fission reactors. The role of renewables is very important in the long-term energy mix, but not expected to increase much in the next 20–50 years, barring some drastic technological innovation in these fields (Lewis, 2001).

There are three challenges for fossil fuels: limited supply, effect on environment, and transportation. Fossil fuels come from a "depleting" resource. The reserves for oil, gas and coal are about 1050, 946, and 3,650 billion BOE, respectively, today. The historical data (Figure 1) on reserves (R in 10 billion barrel unit for oil and in trillion cubic meter unit for gas) and production (P in a million barrel per day unit for oil and a 100 billion cubic meter per year unit for gas) show that, in the past 20 years, the reserve to yearly production ratio (R/P, years) has increased from 29 to 40 for oil and from 47 to 60 for gas (BP, 2003). The R/P is about 230 years for coal and has not changed much in the past 20 years. The reserves are defined to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known deposits under existing economic and operating conditions. The resource estimates (includes hydrocarbons presently considered commercially nonrecoverable, ill-defined assets) are much higher than reserve estimates and is reported elsewhere (Skov, 2003). The consumption rate numbers are close to the production rate numbers. This trend in R/P for oil and gas may appear counter-intuitive, but it is possible due to improved technology in exploration and production. If these sources are going to last for 50–100 years, more oil and gas have to be explored and produced economically. This oil and gas can come from fields buried in deep oceans, viscous oils like Athabasca tar sands, hydrates in marine sediments (and the arctic), and unconventional gas resources like Devonian shales, to name a few. More than half the oil found in reservoirs is typically left behind at the time of reservoir abandonment. Cost-effective enhanced oil recovery techniques are needed to improve this efficiency. Research in improved exploration and production techniques will play a major role in the next 20–50 years and is the topic of discussion in this article.

Use of fossil fuel leads to carbon emission into the atmosphere. There is a lot of uncertainty in global atmospheric carbon data, but it

(Petit et al., 1999) shows that it has fluctuated between 200 and 280 ppm for the last 400,000 years prior to the industrial revolution and has increased now to 370 ppm. According to Kaya identity (Hoffert et al., 1998), net carbon emission=Population×(GDP/Population) ×(energy/GDP)×(carbon emission/energy)–carbon sequestered. Hoffert et al. (1998) show historical trends and future projections for each of the above variables. Global carbon emission can be slowed down by using efficient engines, fuels with lower carbon to hydrogen ratio (C/H), and carbon sequestration. The research in all these areas is essential. The fuel of choice is slowly evolving to lower C/H from wood to coal to oil to gas to hydrogen. Note that, hydrogen is not a primary fuel where as the other three are. Natural gas is the primary fuel with the lowest C/H, has overtaken coal in the last few years in terms of consumption, and is very attractive as the primary fuel for the 21st Century. Hoffert et al. (1998) show that to use energy at the projected level and keep the atmospheric CO_2 level below 560 ppm (twice the preindustrial level), a significant part of the energy has to come from a carbon-free energy source (e.g., fossil fuel with carbon sequestration, solar or nuclear).

The production and consumption locations of fossil fuels do not overlap well. Few countries (the Middle-East in the case of oil and Russia-Iran-Qatar in the case of gas) hold more than 65% of the present reserve (BP, 2003). About 65% of the consumption is in the U.S., Europe, and China (increasing at a fast rate). Transportation of primary fuels (or secondary fuels) is an important issue. Transportation of gas is more difficult than oil. LNG and CNG are two ways of increasing the energy intensity of gas and are being used. Gas-to-liquid (GTL: oxidizing natural gas to diesel, naptha, methanol, ethanol, etc.) and gas-to-solid (GTS: converting natural gas to hydrates or other solids) conversion technology can improve utilization of remotely located gas. More research should be directed towards transportation and distribution of gas. Hydrogen is being touted as the environmentally friendly fuel of the future, but enthusiasm has to be tempered by reality (Ogden, 2002). Hydrogen can be used in combustion engines, as well as fuel cells (no NOx emission). However, hydrogen is a secondary fuel and the source for hydrogen is fossil fuel for the foreseeable future barring breakthroughs in solar or nuclear energy. Thus, we need to produce fossil fuel to meet the future hydrogen demand. About half of our energy use comes from distributed use (e.g., cars, home heating, and small industries). Hydrogen can be a fuel for distributed use, but it has to compete with electricity and traditional hydrocarbon fuels (diesel, gasoline, and natural gas). Hydrogen, like most fuels, is probably competitive with electricity for automotive and home use. Hydrogen can compete with hydrocarbon fuels in terms of carbon emission because carbon emission gets displaced from distributed points of use (such as cars and homes) to chemical plants producing hydrogen. However, there are many issues relating to efficiency, safety, and distribution of hydrogen. There have been recent concerns about the damage to the stratospheric ozone by the leaking hydrogen (Tromp et al., 2003).

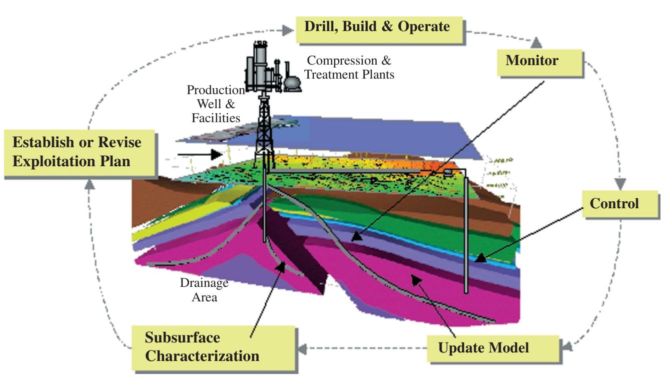

Figure 2. Off-shore reservoir showing its multilateral wells, production platform, and the reservoir management cycle.

Exploration, production, transportation, distribution, and carbon sequestration are the near-term energy challenges. Many of the new exploration areas are in a hostile environment, e.g., deep water, the arctic, and deserts. Figure 2 shows a typical off-shore platform with wells penetrating many producing layers. The depth of water at which platforms are set keeps on increasing; now, it has reached about 9,000 ft (9 times as tall as the Eiffel tower). Since the platforms are expensive, many wells connect to a single platform and each well can be a multilateral reaching many horizons of producing formations. The fluids extracted come from typically hot reservoirs through the cold bottom of the ocean to the top of the platform where they are processed before being delivered to ships or pipelines. The transport, phase behavior, materials, simulation, and control are some of the key technical issues, which are detailed in the next few sections.

Hydrocarbon Recovery and CO_2 Sequestration

Managing uncertainty plays a bigger role in finding and producing reservoirs than in petrochemical processing. To find hydrocarbon reservoirs, typically, seismic surveys are conducted first, followed by well drilling and initial reservoir characterization (also called formation evaluation) (Clark and Kleinberg, 2002). Three-dimensional (3-D) seismic has improved the accuracy of exploration. Wells are no longer just vertical; they can be horizontal or multilateral (Figure 2). Gamma ray, neutron, density, and electrical logging have been used for a long time. NMR logging is gaining acceptance. Logging while drilling is becoming common. Near IR techniques have recently been developed for *in situ* oil compositional analysis (Dong et al., 2002). Pressure transient analysis is being performed with realistic reservoir models. New logging techniques are needed for probing formation many meters away from the wells, especially while drilling. Better understanding of electrical and NMR logs are required for reducing uncertainty in formation evaluation. Understanding transport in porous materials can help improve logging interpretations.

After an initial reservoir characterization, production facilities are installed and then oil is extracted in several stages (primary, secondary, and tertiary). Pressure depletion (primary), water flooding, and gas drainage (secondary) are common techniques, but leave behind more than half of the original oil in the reservoirs. CO_2 and enriched gas flooding (tertiary) are now commonly practiced techniques where these solvents are available (Lake, 1989). Thermal techniques, such as steam flooding, air combustion, steam-assisted gravity drainage, and vapor extraction methods are suitable for viscous oil. Chemical methods, such as alkaline-surfactant-polymer (ASP) methods, have proven to be technical success in some fields, but are not very popular in the present oil price scenario. Microbial techniques are being developed and show promise. Foams and polymers (Willhite et al., 2002) have been developed to divert fluids in the near well-bore regions and provide mobility control deep inside the reservoirs. Challenges include developing surfactants for carbonate reservoirs, reducing cost for the ASP process, and improving sweep (Xu et al., 2003) in many of these processes, especially in fractured media.

The life cycle of such extraction projects is typically 30–50 years. For the new projects (e.g., deep water), the initial investments are enormous; thus, efforts are being made to shrink the life cycles by a factor of 5–10 (Gaurithault and Ehlig-Economides, 2001). This calls for better and deeper (away from the well) understanding of the formation and the recovery processes. Application of tertiary processes from the beginning (i.e., skip primary and secondary production) can increase oil recovery and reduce the life cycle (Jerauld, 2000). This, however, comes at the expense of higher risk. Developing technology to minimize this risk would be important.

Producing conventional gas is comparatively simpler than producing oil; the key problems are proper stimulation and not missing thin layers. There are, however, many unconventional resources for natural gas, such as coal-bed methane, tight (micro-Darcy) sands, Devonian Shales and hydrates. Technology is available to produce the first three resources at the appropriate price. Enormous deposits of natural gas hydrates are present under the ocean floor and in arctic sediments below permafrost layers. Formation evaluation techniques have not been developed to map the density and extent of these deposits. Production of these hydrates may lead to ocean floor instability and natural gas release to the ocean. Safe and economic production techniques should be developed for hydrate deposits.

Large amounts of CO_2 can be sequestered in geologic formations. CO_2 can be injected in depleting oil reservoirs to sequester CO_2, as well as enhance oil recovery. It can be injected into deep coal seams, saline formations, and Devonian shales. Injection of CO_2 into the deep ocean to form hydrates has also been considered (Wawersik et al., 2001). The long-term consequences for such injections are currently being researched. Transport, reaction, and phase behavior of such systems need to be understood and modeled.

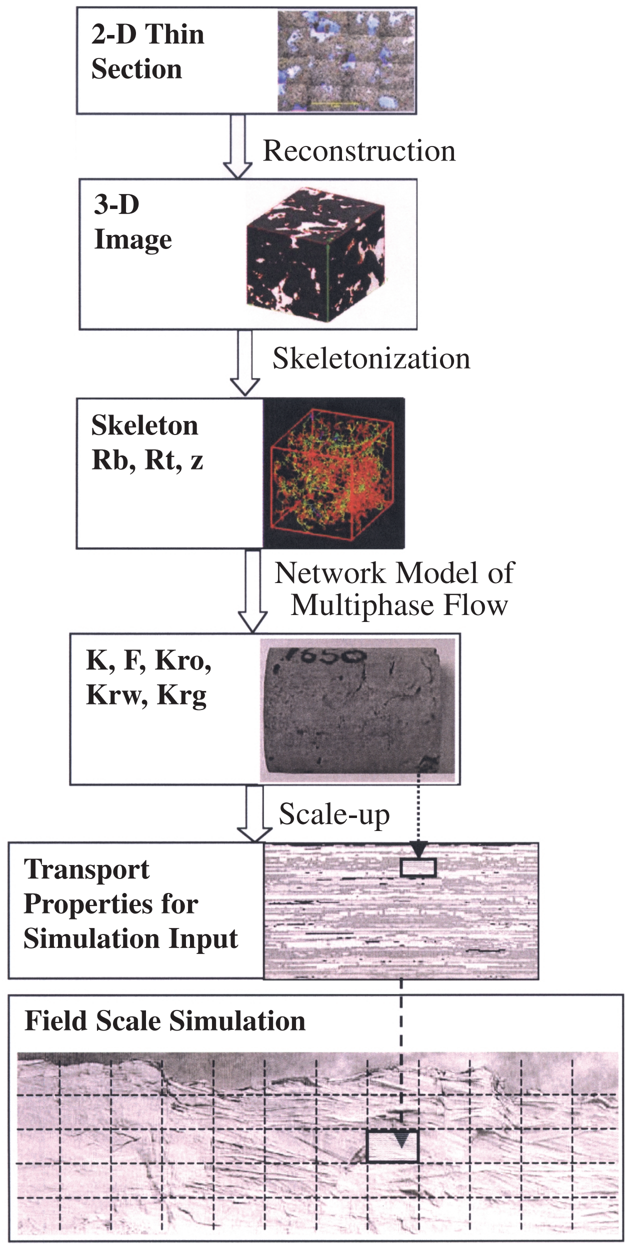

Figure 3. Upscaling of reservoir transport properties showing a 2-D thin-section image, corresponding 3-D image, pore network approximation, core, subgrid heterogeneity and reservoir heterogeneity.

Structure and Transport

Oil, gas, and hydrates exist in the Earth's upper crust within sediments or porous materials. The Earth's crust contains many porous materials, e.g., soil, sandstones, carbonates, and shales. The structure of these porous formations is complex and involves many length scales. These sediments are deposited in sedimentary basins and have been chemically altered through diagenesis over millions of years. There are basin structures which are of the length scale of 100 km. Within these structures, one finds reservoirs that are hundreds of meters thick and several km wide. Reservoirs have sedimentary layers, which are of the order of 1 m thick (Figure 3). Within the layers are cm thick sublayers. Within the sublayers are pores, which are of the order of 1–20 μm. Within the pores, there may be clay structures, which are submicron in scale. Many grains can have microporosity. There may be vugs (porosity created by $CaCO_3$ to $MgCO_3$ alteration) in carbonates, which can be 100 μm to several meters. Some porous reservoirs are naturally fractured. The fracture lengths can extend from microns to km. The fracture lengths are often fractally distributed. Geostatistical methods (Deutsch, 2002) have been developed to describe such complex systems based on many methods including fractional Brownian motion, fractals, wavelets, and krieging (Sahimi, 1995). More techniques (Ottino, 2003) are needed to integrate geological information in describing heirarchical media and describe transport in such media.

Network models (Figure 3) try to capture the key features of the porous structure at the pore-scale and predict the multiphase flow/transport coefficients (Blunt, 2001) at the Darcy-scale (a scale much larger than single pores, but smaller than major heterogeneities). Percolation theory has been used to describe multiphase flow and residual saturations (Larson et al., 1981). Pore-scale physics of multiphase phase flow has been obtained by conducting micromodel experiments (Lenormand et al., 1983). Numerical network models were developed in the 1980s to estimate relative permeability and capillary pressures based on generic cubic networks (Jerauld and Salter, 1990). Models have also been developed for dispersion, electrical conductance and NMR response in porous media (Liang et al., 2000). The recent advances in microtomography and computational resources have brought in two important developments: realistic pore-space description (Oren et al., 1998) and complex displacement phenomena, e.g., three-phase flow, mixed-wet media, and high capillary number (Singh and Mohanty, 2003). Some of the initial predictions look promising, but further development is needed to prove whether such techniques are cost-effective and accurate enough to be practical. Outstanding problems in this area include the modeling of flow in more complex structures, e.g., fractured media, clayey sandstones, and vuggy carbonates.

The transport of fluids in porous materials is controlled not only by the structure of the material, but also by the molecular interaction with the pore wall, also known as wettability (Kovscek et al., 1993). In a well-defined system, the contact angles (advancing and receding) at which the interface between the two fluid phases meets a smooth solid surface define wettability. The contact angles, in turn, are related to solid-fluid and fluid-fluid interfacial energies, disjoining pressures of thin fluid layers and capillary numbers (Hirasaki, 1991). Reservoir systems comprised of brine, oil, and minerals are by no means well-defined. The fluids are complex mixtures whose composition changes with pressure and temperature. The brine salinity and pH affect wettability (Buckley et al., 1998). The oil composition also affects wettability, but correlation with resin/asphaltene fractions and acid/base numbers have not given consistent results. Use of new techniques, e.g., atomic force microscopy (Basu and Sharma, 1999), self-assembled monolayers (Drelich et al., 1996), and understanding of structural forces (Wasan et al., 2003) are showing new insights and departure from classical theories. Future research is needed on predicting wettability, contact angle hysteresis, mixed-wettability, and temperature effects.

Many of the recovery processes include transport in porous media accompanied by phase change, reaction, adsorption and dispersion. Phase changes can be capillary condensation, freezing, boiling, drying, gas evolution, hydrate dissociation, miscibility, and microemulsions (Yortsos and Stubos, 2001). The confinement in micropores can affect the phase transitions. The pore microstructure can influence the growth and movement of newly created or depleted phases. Understanding the molecular interactions/microstructural effects and representing them in a bigger-scale model is a challenge. In reactive systems, flow and reaction can be highly coupled, e.g., in acidization of carbonate rocks (Fredd and Fogler, 1998). In recent work, Balakotaiah and Chang (2003) have pointed out some fundamental problems associated with the parabolic form of the macroscopic convection-dispersion equations. They propose a two-concentration model for both dispersive and reactive flow. Natural systems continue to reveal instances of nonclassical behavior (Bryant and Thompson, 2001). In some applications, it establishes the necessity for multiscale modeling starting at the pore-scale.

Complex Fluids

Complex phase behavior and fluid properties are associated with injected fluids in exploration and production operations, reservoir fluids, and the interaction between the two. Reservoirs are drilled with drilling fluids. The purpose of drilling fluids is many fold: to provide lubrication to the drilling bits, to pneumatically convey broken rock bits up the well, provide appropriate pressure at the producing zones (so that the well does not blow up), maintain stability of open hole, and minimize the invasion of drilling fluids into the producing zones (Dobson et al., 2000). Many surfactants, polymers, salts, and particles are used along with water and/or oil to form drilling fluids. As the horizons for drilling move to deep and off-shore reservoirs, these drilling fluids are subjected to higher temperature, pressure and higher temperature swings (e.g., close to freezing temperature of ocean floors to 400°F in deep wells). Environmental needs drive fluids to be water-based; faster drilling drives the fluids to be oil-based. There is a need for oil-based drilling fluids to be electrically conductive for subsequent electrical logging. Underbalanced drilling requires fluids of lower density and understanding of air-slurry flow. Understanding the rheology of these fluids, associated heat transfer, and interaction with the reservoir (clay swelling and plugging of layers) and monitoring of these fluids are important issues. Many well completion operations also need complex fluids. Gravel packing needs fluids that are viscous in certain parts of the operation and inviscid in other parts of the operation. pH-sensitive microstructured fluids are being developed for such operations (Al-Anazi and Sharma, 2002). Fracturing and acid stimulation involves fluids of complex rheological behavior. Gels, foams, and foamed gels are used to treat the near-wellbore region and divert other injected fluids to proper geologic layers (Willhite et al., 2002). Understanding phase behavior, kinetics, rheology, and interaction with porous media/oil is important.

Reservoir oils are composed of many components, but if the extraction process does not involve their separation, it is unnecessary to characterize them in any detail. Most oil production processes do not involve active separation of the oil components, but pressure and temperature fall as the oil moves from the reservoir through the wells to the surface facilities. The P-T pathway may intersect many thermodynamic phase boundaries. The fluid may cross an asphaltene destabilization point before the bubble point. Asphaltenes may flocculate and stick to the pore wall or the wellbore at the destabilization point (Wu et al., 2000). As the gas is released from the oil at the bubble point, the asphaltene may dissolve back in the oil. At low temperatures, waxes drop out of certain oils. Under very low temperature (but common at ocean floor condition), natural gas and water form hydrates (Sloan, 1998). These solids precipitation can plug the near-wellbore region, well bores/pipelines and stop production. Crude oils can also foam or form emulsions due to their colloidal nature reducing the efficiency of separators (Poindexter et al., 2002). Much research has been directed toward understanding the composition of oil and their colloidal property and solids formation, but quantitative models and *in situ* detections are still a ways off. A new area of "Petroleomics" is emerging which involves getting a detailed analysis of the oil composition by Electrospray Ionization Fourier Transform Ion Cyclotron Resonance Mass Spectroscopy (Hughey et al., 2002) and relating it to oil properties.

In some recovery processes, injected fluids and reservoir fluids mix and the fluid compositions change. Typically, oils are characterized by an equation of state (e.g., Peng-Robinson) with about 10–15 pseudocomponents for gas-flooding or condensate reservoirs (Firoozabadi and Pan, 2002). These pseudocomponent characterizations are often based on matching a few PVT experiments and do not include saturate/aromatic/resin/asphaltene characterization of oils. Asphaltene precipitation models are often heuristic (Wu et al., 2000). Development of petroleomics may bring more mechanistic understanding of oil-solvent interactions. Oil and field brines mix with alkaline-surfactant-polymers in ASP flooding (Lake, 1989). Steam injection into heavy oils/tar sands distills light oil and moves them forward. Air injection creates *in situ* combustion, CO_2 generation, and miscible front development. Mechanistic compositional models need to be developed for mixing of these fluids.

Multiscale Modeling

Modeling processes in reservoirs spans many length and time scales. It is impractical to model a big reservoir at a pore-scale. Pore-scale processes are averaged to describe processes at a Darcy- or continuum- (~cm) scale. It is often too time-consuming to even model reservoirs at the cm scale. Usually, reservoirs are discretized into about 100,000 grid blocks for simulation. The heterogeneities at the grid block scale are modeled explicitly, but subgrid heterogeneities and processes need to be incorporated by proper upscaling. The timescales of reservoir processes can vary from fast reactions (seconds in hydrate dissociation) to slow reactions (leaching of minerals in CO_2 sequestration) and slow movement of convective fronts (in waterflooding, for example).

Numerical simulations of reservoirs are often conducted by the finite difference method (Lee et al., 2002) in the petroleum industry because it is easy to include all the mechanisms, e.g., convection, dispersion, multiphase flow, gravity, compressibility, capillarity, phase behavior, reactions, and adsorption. Numerical models of multimillion grid blocks have been conducted, although they are uncommon and too slow (weeks and months of computational time) for many applications. Finite-element methods have been tried, but seldom used, because of the lack of demonstrated advantage. Streamline methods have been developed for higher resolution, but some cross-flow mechanisms (e.g., gravity, capillarity, and transverse dispersion) are not adequately represented. Streamline methods are effective for processes dominated by the heterogeneity and can be incorporated in the finite difference scheme as a preconditioner (Osako et al., 2003). Dual continuum (porosity or permeability) modeling has been developed for fractured media. Simulators are either noncompositional/compositional or thermal/isothermal depending on the application.

Recent developments in reservoir simulation include efficient gridding (unstructured gridding that honor geology more accurately, perpendicular bisector/voronoi gridding, and dynamic gridding that refine grids only where it is needed), integration of reservoir simulation with wellbore and facilities simulation (Beckner et al., 2001), (4-D) finite-element method, and parallelization.

The fields are notoriously heterogeneous at many scales and the application of laboratory-measured quantities needs scale-up. Single-phase flow has been scaled up properly. Many issues remain unresolved for multiphase flow (Christie, 2001), reacting media, phase behavior, and unstable flow scale-up. Matrix-fracture transfer terms need to be scaled up properly for compositional dual permeability simulation. Thermal compositional simulations should be developed for several applications (hydrates and gas condensates). Thermal and transport constitutive relations are not very well known and need to be determined. Many simulators slow down when small-scale processes are included, such as capillary pressure and reactions. The challenge is to develop multimillion grid block simulations that can include all geological details and physical mechanisms and run efficiently in parallel and distributed computers with a quick turnaround.

Monitoring and Control

The reservoir management cycle (Figure 2) starts with reservoir characterization that includes exploratory drilling, logging, well testing, and fluid analysis. With a reasonably good model of the reservoir, an exploitation plan is tailored to meet specific business needs; this plan involves the choice of a reservoir recovery mechanism, well locations and number, and the initial design of a production facility. Financial feasibility is assessed at this stage. Then wells are drilled and surface facilities are constructed and operated. New data comes in as new wells are drilled; the response of the wells are monitored and controlled to some extent. The new well data and the response of the system can be used to update the reservoir characterization model and the whole process can be repeated (Saputelli et al., 2002). This reservoir management cycle is practiced for a long time in one way or other, but the cycle time has been notoriously slow (many years). As the industry moves into challenging production environments (e.g., deep off-shore), improved recovery takes place, marginal projects and sensing/control/computational techniques develop; there is a demand to decrease this cycle time.

The so-called "smart wells" are being developed (Glandt, 2003) which include a battery of completion equipment designed to monitor well operating conditions downhole (flow rate of each phase, pressure, temperature, distributed data using fiber optics technology, phase composition, water pH, etc), image the distribution of reservoir attributes away from the well (resistivity and acoustic impedance), and control the inflow and outflow rates of segregated segments of the well. Expandable metals have ushered in a paradigm shift in well construction and remediation recently (Emerson, 2003). Materials sensitive to pH, salinity, temperature, etc. and lab-on-a-chip type sensors would have a place in the smart well technology. This technology, in combination with quality data at the surface and other nonwell mapping technologies like time-lapse (4-D) seismic, provides the tools to manage wells, identify undrained oil, and make informed decisions to optimize hydrocarbon recovery.

Hydrocarbon production systems operate in an uncertain dynamic environment (unknown geology, complex fluids, and uncertain market price) where decisions have to be made recurrently about drilling, well control, equipment, etc. Computer integration of the field operation is essential to coordinate both human and control activities for maximizing corporate objectives. A multilevel, multiscale approach is being developed to integrate reservoir management with model-based regulatory control, supervisory control, scheduling, and operational planning (Saputelli et al., 2002). The goal is to develop a self-learning and self-adaptive machine for reservoir management.

Prospects and Challenges for Chemical Engineers

The primary fuels for the next 20–50 years are going to come mostly from fossil fuels. Environmental reasons are going to drive the transportation fuels in the direction of lower carbon to hydrogen ratio, i.e., natural gas and hydrogen. Hydrogen (as a secondary fuel) will be derived from fossil fuels. Fuel cells will be used more for power generation in distributed and portable systems. Production and distribution of hydrogen is going to be an important issue. Catalysis will play a very important role in the development of fuel cells (Park et al. 2000), hydrogen generation, and fuel transportation (GTL, GTS). If *in situ* techniques can be developed to produce hydrogen directly from fossil fuels underground, carbon sequestration would no longer be an issue.

As the rate of finding new reservoirs drops off, enhanced oil recovery will become more important. Cost-effective recovery techniques and mobility control agents must be developed especially for heterogeneous and fractured reservoirs, and viscous oils/tar sands. Near wellbore treatments can be controlled and targeted for higher effectiveness. New materials (surfactants, polymers, and nanomaterials) are needed whose properties can be tuned. New structural materials will be needed to build off-shore structures, drilling/completion rigs, and smart wells. Molecular/mechanistic models are necessary to understand complex reservoir fluids and their interactions with injected fluids. Transport models are needed to accurately simulate reservoir performance.

Future hydrocarbon reservoirs would have to be managed more efficiently. Continuous field-wide optimization would require better sensors, deeper (away from the well) formation evaluation, smart wells, better reservoir models, multilevel control, and optimization schemes.

Energy is the most important problem facing humanity. The energy landscape consists of many options: fossil fuels, renewables, and nuclear. Their relative importance will change in the coming decades. Breakthrough research is needed in all energy options to develop a sustainable, economic, and environmentally-safe energy mix. At the University of Houston, we are trying to integrate different aspects of energy into our teaching and research curriculum. Energy integration should be an integral part of chemical engineering curriculum to prepare future chemical engineers to meet the energy challenge.

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