A step in the right direction

The US' energy infrastructure will need major capital investment to meet future demand. But, before any construction can begin there will be a plethora of applications, permits and licences. By Branko Terzic, global regulatory policy leader, energy and resources, Deloitte Services

Throughout the US, aging energy-infrastructure facilities need to be replaced, capacity expanded and technology modernised. All this new capital investment can be made only with the regulatory approval of state and federal agencies.

The addition of energy infrastructure is subject to economic, design, location, cultural artifact, environmental and other regulatory permits issued by multiple state and federal agencies. Applicants and some consumers complain that this proliferation of regulatory approvals has led to unnecessary delays and increased costs of infrastructure addition, but recent federal law has taken some small steps to improve the situation in the electricity sector and for liquefied natural gas (LNG) terminals.

At state level, the regulation of infrastructure expansions is specific to the type of utility and property. Many states have individual laws covering power plant, electricity transmission or distribution infrastructure construction.

Individual state and federal laws designate as public-service or public-utility companies (the terms are interchangeable) private-sector companies providing electricity and gas services. These companies have traditionally been assigned a monopoly franchise to provide service to a geographic area, in return for which the rates for service and conditions of service are set by a regulatory agency – public-service commissions (PSC), or public-utility commissions, after the industries that they regulate. At the national level, the Federal Energy Regulatory Commission (Ferc) regulates the public utilities designated by federal law.

Individual states and the District of Columbia regulate retail electricity and gas distribution within their boundaries. Ferc regulates interstate gas pipelines, LNG terminals, the wholesale sale and transmission of electricity and certain hydro-electric plants. Public utilities also have state or federal government authority of eminent domain – the state can transfer authority to the public utility to condemn private property to enable construction of necessary infrastructure, a rarely used process.

The basic regulatory principle

Regulation is predominately based on the cost-of-service, or revenue-requirement principle. Also called rate-of-return regulation, the basic regulatory principle is that a public utility has the right to recover, in rates set by the regulator, an amount each year sufficient to meet operating expenses, depreciation expenses and taxes and still provide the opportunity of (but not guarantee) a return for investors. In setting rates, the regulator must establish the investment-rate base – to ensure investment can provide the level of service specified by regulation.

At the federal level, Ferc has authorised the use of a second method of determining rates, market-based pricing – a Supreme Court-approved alternative to Ferc's traditional cost-of-service methodology for wholesale power sales under its jurisdiction. Under market-based pricing, a seller of electricity can obtain a certificate to sell at market prices if it can demonstrate to Ferc that it does not have market power in the relevant wholesale market. Ferc retains full authority to re-impose regulated-rate setting in the form of rate caps or cost-of-service-based rates in the event of market failure.

Most PSCs establish a minimum threshold amount for capital projects over which the utility must apply to the PSC for pre-approval of the construction project. This is a very state-specific requirement. In Wisconsin, the threshold is $1m. In general, for an electricity utility, construction projects involving power plants, transmission lines, major sub-transmission lines, transmission sub-stations and distribution sub-stations are above the threshold and require pre-approval.

A few states do not have a pre-approval requirement and deal with issues of prudence of the investment, the need for the project and level of cost at the time of a rate-case application by the utility. The utility would build the facilities taking the risk that all or part of its construction expenditure could later be rejected by the PSC – at the time of the next rate case. Most utilities would provide the PSC with early information and cost justification for major projects, although a formal approval process is not required by law.

Establishing the need

In states where the PSC has pre-approval authority, the utility would have to apply for formal project approval in advance and request a Certificate of Approval for construction (CA) – in some state jurisdictions, and at Ferc, a Certificate of Public Convenience and Necessity (CPCN). The purpose of the CA/CPCN is to establish the need for the project, assess available alternatives, present the cost analysis and include any required environmental assessments.

Project construction may begin once a CA has been issued by the PSC. The certificate process may or may not involve the requirement for public notice – the process may require or warrant a public hearing before administrative law judges or, if the project is large or controversial, before the full commission.

In most states, electricity supply is provided by utilities with generation, transmission and distribution assets. Except in a few cases, California as the prime example, authorisation to construct new power plants rests with the PSC. In that case, the power plant CA contains the full economic, technical and reliability justification for the proposal. Ferc has no jurisdiction if the plant's output will supply the utility's native-load customers. Even in the case where some sales are made wholesale, requiring Ferc approval, only the power sold wholesale would fall under Ferc jurisdiction. Ferc has no authority to issue a CA and cannot grant eminent domain for a conventional power plant project.

An independent power plant (IPP) – also referred to as a merchant plant – is one not owned by an electricity utility. As in the case of utility-owned power plants, each state has established its own procedures for permitting construction.

Because IPP's sell power wholesale, they are subject to full-rate regulation by Ferc and usually apply for market-based rather than cost-of-service rates. However, state and local construction, environmental, water and land-use laws require permits from multiple state and local agencies. Under federal law, Ferc has authority only over plant economics, in terms of rate setting, and has subsequent authority to approve sales of existing power plants with approved Ferc tariffs.

Some states have special laws and siting agencies for power plants over a certain size – for example, the California Energy Commission has sole authority to license power plants of 50 megawatts (MW) and larger, as well as transmission lines carrying 50 MW or more in the state. Each state has its own energy-planning laws, environmental-protection requirements and specific authority and requirements concerning the location and construction of plants.

To date, all US nuclear plants have been built by investor-owned public utilities or government agencies. For utility-owned nuclear plants, economic approvals and certificates of authority have come from PSCs. Ferc has no construction authority, but has rate-setting authority for sales to the wholesale market. The US Nuclear Regulatory Commission (NRC) has exclusive jurisdiction over the licensing and regulation of civilian nuclear plants to protect public health and safety and maintain national security. The NRC issues standard design certifications, early site and construction permits, operating licences and combined licences for commercial nuclear facilities. The Energy Policy Act 2005 (EPA 2005) provides incentives, reduces risk and has created an expedited process for new nuclear-production approvals, including the issuance of a combined construction and operations licence.

The NRC can revoke licences, close plants and invoke fines for safety violations. Consequently, nuclear plants are jointly regulated by the state and federal governments, with the state PSC regulating economics and NRC regulating safety and operation.

Nuclear considerations

The Nuclear Energy Institute says nine nuclear projects are being considered. Three consortia, comprising 18 firms, are preparing nine combined-licence applications for 14 plants in nine southeast states. Four other companies are also evaluating the new nuclear option. The first submittals to the NRC should occur in 2007, with licence approvals expected in 2010. If this schedule is achieved, the US would have the first generation of these new nuclear power plants in operation by 2014-2015.

Ferc regulates non-federal construction and operation of hydro-electric projects on federal waterways. Four types of licence have been issued: less than three years; 50 years; and major and minor licences based on predicted horsepower. Most recently, Ferc has dealt with issues of re-licensing or recapture of the 50-year licences. Federal hydro-electric projects are not under Ferc jurisdiction and have their own federal enabling statutes.

Exclusive authority over approval of transmission-line construction was with PSCs until the passage of the EPA 2005, which gave Ferc authority to approve construction and federal eminent domain for qualifying proposals. Ferc can now authorise transmission lines routed in certain corridors where the expansion of transmission is deemed necessary for national security by the Department of Energy.

In all other cases, individual state laws continue to direct the state PSC or another designated agency to approve the siting/routing of transmission-line construction, whether for intra-state or inter-state purposes. In some states, the PSC has both site- and construction-approval authority. Applications for transmission-line construction follow regular CA procedures, as specified by state laws.

Some experts say it has become more difficult to build transmission facilities than individual power plants, because of the linear nature of power lines, which usually cross many political jurisdictions and the property of numerous land owners. Transmission lines also draw opposition over concerns, warranted or unwarranted, about electro-magnetic fields and aesthetics. A new development is the creation of independent transmission companies, which own transmission assets, but no generation of distribution facilities. Because such companies provide third-party access, their rates are fully regulated by Ferc.

A number of entities are designated as independent system operators (ISO) and regional transmission operators (RTO) – not-for-profit organisations that do not own transmission assets, but control the use of the member company's transmission system by dispatching power plants to maintain system balance. They also operate wholesale power markets. Not all electricity utilities have become members of an ISO or a larger RTO. Each ISO is regulated by Ferc and has specific rules concerning operation.

Transmission rates for all US entities are set by Ferc under cost-of-service methodology. Ferc has recently indicated that it would encourage transmission-capacity expansion by offering incentive rates and the EPA 2005 enables this.

Gas pipelines, storage and LNG

The interstate gas industry is subject to Ferc regulation – it has approval authority for construction of new interstate gas pipelines and storage systems, and LNG import facilities. Additionally, other approvals must be obtained from applicants wishing to build facilities.

Ferc uses cost-of-service methodology to establish pipeline service rates and requires the pre-approval of pipeline construction through a CPCN. Ferc is also the lead agency in issuing Environmental Impact Statements (EIS). Ferc's process requires the issuance of public notice and commensurate public hearings. Upon collection of the record, comments and filed materials, Ferc will issue Preliminary Determinations, Draft EIS, Final EIS and Certificate.

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A recent pipeline-construction applicant for a facility crossing two US states and into Canada cited the need for 603 environmental-filing requirements. Ferc issued 18 other official Notices to Proceed and the Canadian crossing required a US Presidential permit and US Presidential International Border Crossing Permit, as well as various Canadian permits. Other US agencies involved in the process of licensing an interstate pipeline can include: Army Corps of Engineers; Coast Guard; Department of Agriculture; Environmental Protection Agency; Fish and Wildlife Service; and The National Park Service.

At state level, gas-pipeline projects usually require permits or reviews by state environmental and land-use agencies, and local municipalities. These entities issue road-crossing, zoning-variances, soil and water conservation permits, and other special local permits. As in the case of electricity-transmission construction applications, local opposition can be based on environmental, aesthetic and safety concerns. The not-in-my-backyard syndrome, affects infrastructure proposals across the country.

Ferc regulates construction of underground gas-storage facilities. In a new and positive development for future construction, under the EPA 2005 Ferc has authority to extend market-based pricing to new storage capacity, even if the company is unable to demonstrate that it lacks market power.

The authority to construct LNG import or export facilities onshore lies with Ferc and its jurisdiction was clarified and improved by the EPA 2005. Ferc has "exclusive authority to approve or deny an application for the siting, construction, expansion and operation of an LNG terminal". But, states retain rights under various other acts, such as the Clean Water Act and the Clean Air Act, to deny approval for construction. To date, Ferc has acted on approvals for 12 LNG import terminals. The US Coast Guard has approved two offshore terminals.

An uncertain future

Regulatory and market uncertainties – particularly over environmental policy – are increasing the risk for choosing power supply options. How companies prepare and manage uncertainty will separate the winners from the losers. By Michael King and Michael Rosenzweig, senior vice-presidents, Nera Economic Consulting

The 1970s and early 1980s were a period of great uncertainty in the energy industry, largely driven by oil-supply disruptions and their reverberations. Uncertainty today is driven by concerns about supply, but also by regulation and policy. These uncertainties are affecting the choices confronting North America's power supply.

Recent years have made painfully transparent the risks generators and customers face from volatile fuel prices. Yet price risk is only one source of risk confronting the industry. North America has been experimenting with deregulation, and incomplete and transitional regulatory structures are a major source of risk. Compounding commodity and regulatory risk is uncertainty over environmental policy and the implications it will have for recapitalisation of the generation sector.

No-one can foresee the resolution of all of these factors. But many parts of North America require additional power-generating capacity and the commitment to invest is a bet on the ultimate resolution of these risks.

Regulatory risks in power-supply choices

Over the past 30 years, the US has experimented with competition in power supply. A split in regulatory philosophy has marked the past 10 years: between states that restructured their power markets, often requiring vertically integrated utilities to divest generating capacity; and states that continued to rely on a vertical-integration model and the historical approach to state and federal regulation. Both regulatory arrangements present risks.

Merchant generators are more susceptible to market institution risk – the risk of how they will be paid. Ten years into restructuring, the US is yet to decide if an administrative market to support capacity is a necessary component of competitive energy markets. While some markets have adopted some sort of institution that monetises capacity others have not. And in markets where generation has not been divested, merchant generators have no consistent market mechanism to compensate them for the value of their capacity in meeting planning reserves.

States that have allowed or required divestiture of generating capacity have also taken different paths to providing supplier of last-resort service. In Maryland, the expiration of rate caps led to a request for proposal (RFP) for power supply, but the result of that auction was not acceptable politically. New Jersey has successfully run an auction for basic generation service for several years, while New England utilities have typically procured generation through a reasonably effective RFP process.

Merchant generators have also complained that solicitation processes for new supply in markets that remain vertically integrated have not dealt with affiliate issues. Several utilities have conducted solicitation processes that competitors have alleged were unfair and predetermined in their result of selecting a utility or affiliate option. While some of these claims are likely to be little more than sour grapes, not all are, as evidenced by the Federal Energy Regulatory Commission's issuing of guidelines for solicitation processes. Additionally, some utilities have bypassed the solicitation process and announced new utility generation projects without comparing the costs of those plans with market purchases or offers from independent power producers to construct alternative new plants.

In states that are moving back to a vertically integrated structure (or never left it), the risks to utilities in selecting power supply options can be significant. While some states may remember some of the regulatory-risk management techniques that were brought to bear in the 1990s (competitive solicitations), many still are struggling with affiliate issues.

The bigger issue is that the restructuring process is incomplete. Market and regulatory structures are transitional and pose significant risk to generators, whether they are merchant players or utilities. Some markets appear more mature and stable (PJM and the northeast) than others (California). But regulatory risk is substantial. New supply options must be considered in light of the maturity, stability and consistency of the market/regulatory environment.

The environment

Power generation is one of the largest sources of air-pollutants in North America. Yet in the US, the scope and nature of environmental regulation remains unclear, adding substantially to the risk of selecting new supply options. The largest unresolved risk is associated with greenhouse gas (GHG) regulation, but other environmental uncertainties also affect the choice of generation technology.

Recently, the Environmental Protection Agency has begun enforcement actions using the New Source Rule to attempt to force the installation of controls on existing power plants. At the same time, it has attempted to clarify future environmental regulations through rulemaking (the Clean Air Interstate Rule and the Clean Air Mercury Rule, for example) and through proposed legislation (Clear Skies). But these approaches have fundamentally different risk implications.

The effect of the enforcement actions has been to increase the amount of uncertainty around the law and its requirements. There are differences in law based on conflicting decisions from the various courts where the enforcement actions have been brought. Conversely, the rulemakings have reduced the uncertainty of future law. It was only after the regulatory system was clarified that there was a significant increase in the number plants planning to add significant environmental controls.

The nature and timing of GHG controls is a source of significant uncertainty in the selection of supply options. In the US, it is unclear when, if ever, the government will impose limits on GHG emissions or the form and level those limits might take. Meanwhile, Canada appears to be reconsidering its obligations under the Kyoto Protocol. As a result, it is difficult to decide whether less carbon-intensive technologies – such as nuclear, gas and renewables – are worth the cost premium they command in the marketplace.

Given that power plants are long-lived assets that require 25 years or more of operation to recover their capital cost, it is particularly problematic to make decisions on the fuel and technology of future supply in the face of the uncertainty over carbon regulation. Nuclear, despite the promises of decreased cost, permitting and construction time, still requires production subsidies or a carbon tax to be competitive with fossil-fired generation. Renewables also require intervention to be economic. And while new coal-fired power plants appear economic today, in many parts of North America future carbon schemes could eviscerate their competitive advantage.

However, given the rate of growth in electricity demand in North America, new plants must be built before the carbon regulatory scheme is determined. Companies planning new power supplies should defer decisions as long as possible and stress test the decisions thoroughly. When they can no longer be deferred, companies should identify and adopt the most robust strategies across the range of possible future environmental regulations and market outcomes.

Fuel-price risk

As the former New York Yankees catcher and manager, Yogi Berra, said: "It's tough to make predictions, especially about the future." While there is no doubt the construction cost of generation technologies plays a critical role in the attractiveness of a specific technology, these costs are much closer in time than the cost of fuel that must be incurred over a plant's lifetime.

The US Department of Energy's Energy Information Administration (EIA) has invested considerable time and thought into building forecasting models. However, although the EIA has been forecasting for over 30 years, it continues to show that forecasts will rarely be correct. The EIA's forecasts of quantities consumed and produced have been relatively accurate, with the average absolute percent error ranging from around 2-7%. But its ability to forecast prices is notably poorer. The average absolute percentage error in EIA's price forecast of world oil prices is around 60%, natural gas wellhead prices are about 70% and coal prices around 50%.

Perhaps other forecasters have had more luck with energy commodity prices over the long-run than the EIA. But if they really were able to accurately predict prices, they probably would be trading energy commodities rather than selling forecasting services. When forecasts from the various private sources are assessed over time, there is a clear pattern of upward bias (perhaps reflecting the peak oil thesis) that makes decision processes based on these alternative forecasts very risky.

One of the most significant issues affecting the economics of power-supply options is the future price of natural gas. The late 1990s were marked by the belief that a modular, short lead time and relatively capital-light combined-cycle gas-turbine technology coupled with cheap gas prices would lead to a relative recapitalisation of the US power industry. The surge in capital investment of the late 1990s and early 2000s forecast that gas prices would remain relatively flat.

However, forecasts across a relatively short period of time have been remarkably different. In 1997, the EIA forecast the 2007 wellhead gas price would be $2.38/m Btu (in constant 2006 dollars), but in 2006 forecast that same year's price to be $6.97. The issue is not so much the price level of a particular fuel commodity, but the relative prices of different fuels – while all commodities are dearer, the advantage of one to another is more or less the same.

Forecasts, trading and risk management

A forecast is the view of the forecaster. On the other hand, a forward curve is a set of prices, based on which, one could go into the market and enter transactions for the future purchase or sale of a commodity.

A forecast cannot be transacted. A forward curve can. Why is this distinction important? Trading in energy commodities yields forward curves and counterparties. Trading results in the ability to ascertain what value market participants place on the future worth of commodities. A forecast is only the view of the forecaster, and does not represent the interaction of a willing buyer and seller exchanging money for the future delivery of the commodity.

Without competitive markets and robust trading volumes, decisions about future supply options must be made on the basis of forecasts. Because forecasts are most often wrong, one is well advised to use many different (but consistent) forecasts to ascertain not just the pure value of the decision, but also the risk in that decision. But with forward markets, one can hedge the risk of the decision – transfer the risk of an adverse movement in prices to another, willing party that is probably better able to deal with the risk.

Without robust and deep trading markets for energy commodities, about the only way to hedge risk is physically. This may mean owning gas reserves if one owns a gas-fired power plant, or owning or contracting for the physical delivery of power if one has customer load to serve. These physical hedges, however, are difficult to implement, lumpy and cannot be quickly adjusted, put on, or unwound. The mechanics of physical hedging lead to inefficiencies that are lessened with the appearance of deep and robust trading markets – in both the physical and financial (exchange for money) markets. And physically hedging is more expensive than hedging contractually or financially through risk markets.

Choices, choices

The outlook for the North American power sector is particularly uncertain. While the regulatory, policy, and market risks are daunting, it also faces a crisis in confidence around the fundamental role of competition. Many states are veering from their previous commitments to rely primarily on competition as their tool for managing the wholesale power sector.

There are concrete steps that can be taken to minimise the cost and risk in future power-supply choices:

- Policymakers should recommit to competition in wholesale power supply. Freeing the market to solve the power-supply options will allow the risk of those options to be borne by the owners of in-service power plants, rather than saddling consumers with the outcomes of decisions made in an administrative process ruled by special interests;
- Regulators should design market arrangements that work, recognising that this is a job for experts and not for consensus processes among special-interest groups. Providing customers with rate caps while not providing mechanisms for them either to respond to prices in the short term or hedge the cost of future power supply cannot result in a workable market;
- Regulators and policymakers need to recognise that while intervention in markets is sometimes necessary, it is not costless. The risk-allocation benefits that arise through a competitive market are available to the extent that there is a large volume of trading. Regulatory or political interventions rewards one side of a trade at the cost of the other and the consequences are the destruction of confidence in the market, sanctity of contracts and trade volume;
- Regulators and policymakers should clarify future regulatory initiatives. Reducing regulatory uncertainty allows companies to make better decisions about future supply options and reduces risk;
- Companies should also endorse competitive wholesale markets and encourage the orderly development of trading for risk-management and transfer purposes; and
- Companies must put in place reasonable risk-management governance and control procedures, and apply risk-management techniques in the construction of their supply portfolios.

Oil sands: potential for growth

Oil prices have more than doubled over the past four years as world crude consumption has continued to grow and demand for Opec supply appears to have eliminated its spare capacity. These fundamentals have raised international awareness of Alberta, Canada's vast oil-sands resources. By Wilf Gobert, former vice-chairman, oil and gas analyst, Peters & Co

Alberta, Canada, has three major oil-sands deposits, Athabasca, Cold Lake and Peace River. Alberta's Energy Utilities Board (EUB) estimates the initial volume in-place of bitumen to be 1.7 trillion barrels (see Table 1). Growth in oil-sands production is projected to rise by more than 1.5m barrels a day (b/d) by 2015 under a low oil-price scenario, but a high oil-price scenario could lead to growth of more than 3.0m b/d, if capacity constraints did not exist.

Wilf Gobert

The EUB estimates Alberta's initial established reserves – equivalent to proved plus probable reserves – at end-2003 were 179bn barrels, with 174bn barrels remaining after cumulative production of 4.6bn barrels – 20% of established reserves are mineable and 80% require *in situ* recovery. Ultimate potential reserves (with improved economics and technology) are 315bn barrels, including 63bn barrels from surface-mineable recovery methods. Canada's crude reserves, including oil sands, rank second in the world behind Saudi Arabia.

Reserves: mineable and *in situ*

The surface mineable oil-sands area is defined by the amount of overburden that must be removed to reach the bitumen ore. Overburden of 75 metres or less is considered to be surface mineable. The EUB has designated over 850,000 acres where the overburden is less than 75 metres. Deposits below 75 metres of depth are classified as *in situ*. Because of low gravity and high viscosity, these oil sands require enhanced-recovery schemes, such as thermal stimulation, for the bitumen to become mobile and produceable with a pump.

The in-place mineable volume that is economic to produce is based on economic strip-ratio criteria, a minimum bitumen saturation of seven mass-percent bitumen and a minimum saturated zone thickness of 3 metres. The EUB also applies factors that sterilise volumes from being mineable, such as corridors along rivers and surface facilities. Mining and extraction operations result in an average loss of 18% of the in-place volume.

Established reserves are based on economic cut-off limits and recovery factors. Commercial projects were assigned thermal-recovery factors based on production history (50% for Athabasca, 25% for Cold Lake and 40% for Peace River). Some 80% of total established reserves are *in situ* and only 2% of total reserves (2.5% of *in situ* reserves) are represented by active projects. Additionally, only a small quantity, 1.4bn barrels, have been produced by *in situ* projects.

Before the recent surge in oil prices, low and volatile prices, and the high cost of consuming natural gas for steam generation, discouraged commercial thermal development. However, high oil prices and low capital costs for *in situ* production result in rates of return that exceed that of upgraded synthetic crude. High oil prices and wide price differentials between light and heavy crudes are encouraging proposals for bitumen upgrading by *in situ* producers and by third-party upgraders that have no production interests.

Projects

Three active mining projects had 11.0bn barrels of initial established reserves at end-2004, leaving 24.2bn barrels undeveloped. Active projects had produced 3.16bn barrels at end-2004, or 29% of their initial established reserves. If all projects supplied by mineable oil sands are developed on schedule, synthetic oil-sands supply would grow to 2.7m b/d (assuming Kearl and Fort MacKay projects are upgraded somewhere in Alberta), an increase of 1.9m b/d (see Table 2).

Before the run-up in world oil prices, thermal production of bitumen from oil sands was stagnant in Alberta, at around 300,000 b/d. Supply was dominated by two cyclic-steam projects – Imperial Oil (Cold Lake) and Canadian Natural (Primrose) – initiated before the 1986 collapse in oil prices. After the 1996 agreement between Alberta and Ottawa on a generic oil-sands regime (1% royalty until capital payout, then 20% of net operating cash flow, net of incremental capital) and after the recovery of prices began in early 1999, oil-sands owners began cautiously to advance *in situ* projects. Since 2002, project proposals have grown dramatically. If all projects supplied by *in situ* oil sands were developed on schedule, production would grow to 2.0m b/d, a rise of 1.6m b/d. However, proposed upgrader construction would consume 1.33m b/d of bitumen, producing 1.15m b/d of synthetic sales.

Table 1: Reserves of crude bitumen

bn barrels	Initial volume in-place	Initial established reserves	Ratio to total (%)	Cumulative production	Remaining established reserves	Ratio to total (%)
Mineable oil sands	**109.95**	**35.16**	**20**	**3.16**	**32.00**	**18**
Active projects		10.95	6	3.16	7.79	4
In situ	**1,587.96**	**143.42**	**80**	**1.43**	**141.99**	**82**
Active projects		4.06	2	1.43	2.63	2
Total active projects		**15.01**	**8**	**4.59**	**10.42**	**6**
Total bitumen	**1,697.91**	**178.58**	**100**	**4.59**	**173.99**	**100**

Source: AEUB

Supply forecast

The Canadian Association of Petroleum Producers (Capp) estimates Alberta's oil-sands production (mining, synthetic and *in situ*) in 2005 at 0.993m b/d, or 45% of Western Canada's total crude production of 2.22m b/d. By 2015, Capp forecasts mined (and mostly upgraded) crude will reach 1.828m b/d and *in situ* will reach 0.864m b/d. The combined oil sands total of 2.69m b/d would represent 75% of Western Canada's total crude production of 3.57m b/d, as conventional light, condensate and heavy crude is projected to fall from 1.22m b/d in 2004, to 0.879m b/d in 2015.

Supply growth is dependent on a variety of factors, but the most prominent issues are world and regional oil prices, labour, capital and operating costs, and pipelines capacity.

Over the past five years, the oil industry and the investment community have dramatically altered their view of long-term prices. Between 1986 and 1999, Brent crude averaged around $17.50/b (WTI $19.00/b). In the early 2000s, international oil companies forecast a long-term Brent price of $15-16/b, while North American companies and investors were assuming a WTI price of around of $18/b. However, in early 2006, some companies were forecasting a long-term WTI price of $40/b, with many investors relying on long-term futures exceeding $60/b. Higher crude prices will generate higher cash flow and earnings, and strengthen balance sheets, enabling the oil industry to contemplate more aggressive capital expenditure (capex), particularly in the oil sands.

Alberta has a population of only 3 million – 10% of Canada's total. The province's employment growth was 3.5% over the past year, double the national average. The Alberta government projects that the province will create the need for 400,000 new jobs over the next 10 years – although only 300,000 jobs will be created at today's growth rate. In October 2005, the Canadian Energy Research Institute (Ceri), estimated oil-sands employment grew by 110,000 workers during 2000-2005 and forecast growth of 151,295 during 2006-2010 and 225,973 during 2011-2015. Ceri's study was based on an expected long-term crude oil price of $32/b for WTI.

Table 2: Oil-sands projects

Mining		Capacity ('000 b/d)		Expansion
Operator	**Project**	**Current**	**Projected**	**time-frame**
Syncrude	Syncrude	350.0	500.0	2012-15
Suncor	Millenium/Voyager	260.0	500.0	2008-12
Shell	Athabasca	155.0	600.0	2010-15
Canadian Natural	Horizon	–	232.0	2009-11
True North Energy/UTS	Fort Hills	–	200.0	2011-14
Imperial Oil	Kearl Lake	–	300.0	2011-15
Synenco	Northern Lights	–	100.0	2011-13
Total	Joslyn	–	200.0	2011-14
Fort MacKay First Nation		–	50.0	na
Total upgraded synthetic*		**765.0**	**2,682.0**	–

Projected capacities and time-frames are speculative, but based on public comments. * Assumes Kearl and Fort MacKay are upgraded volumes

In situ		Current	Projected	Expansion time-frame
Athabasca		**108.6**	**1,564.0**	–
EnCana	Foster Creek	40.0	500.0	2006-15
Canadian Natural	Birch Mountain	–	270.0	2012-18
Husky Energy	Sunrise	–	200.0	2008-15
Suncor	Firebag	30.0	120.0	2006-12
Nexen/Opti	Long Lake	–	144.0	2007-10
ConocoPhillips/Total	Surmont	–	100.0	2006-12
Petro-Canada	MacKay River	30.0	70.0	na
Others		8.6	160.0	2006-10
Cold Lake		**261.0**	**298.0**	
Imperial Oil	Cold Lake	150.0	180.0	na
Others		111.0	118.0	2006-10
Peace River		**21.0**	**123.0**	
Shell Canada	Cadotte Lake	9.0	100.0	2010-15
Blackrock		12.0	23.0	2012
Total *in situ* bitumen upgraded†		**30.0**	**1,229.0**	–

† *In situ* bitumen upgraded is reduced by 15% to arrive at synthetic sales of 1.135m b/d

Source: AEUB

Capital costs of oil-sands plants have escalated dramatically this decade, doubling for an integrated mining, extraction and upgrading operation, from $3bn for an operation of 100,000 b/d, to $6bn. *In situ* operations are considerably less capital-intensive, costing $15,000-20,000 per b/d of capacity. The Ceri study's expected base-case scenario, with a WTI forecast of $32/b, projects' capex for oil sands of $5m a year until 2015, for a cumulative 2006-2015 expenditure of $54bn. But a WTI forecast of $40/b resulted in a cumulative capex of $82bn, mostly through accelerated project spending in 2006-2015.

An Alberta government study forecasts that a base case of cumulative capital for 2005-2015 may be $63.5bn, with a potential of $79.5bn. In both this study and in Ceri's, capex forecasts were before annual sustaining capital of operating plants, which the government study predicts would amount to $16.5bn over the period.

Operating costs and infrastructure

Suncor is the oldest oil-sands mining operator and its lowest-cost producer. Before 2000, in a scenario of WTI averaging $25/b and gas at $4.00/m Btu, it achieved cash costs of $10-12/b of production. Because integrated oil-sands plants consume about 700 cubic feet (cf) of gas per barrel of production, the fuel-cost sensitivity to rising gas costs is around $1.00/b per $1.00/m Btu above a base of $4.00/m Btu. However, the newest oil-sands operation, the Athabasca project, has reported operating costs of $20-22/b, with gas prices of $8.00/m Btu (about $14.00/b before gas costs).

In situ operations have low capital costs, but the value of bitumen production is only 40-60% of the value of light-quality crude, with the discount having both a seasonal and cyclical variation. Steam generation and other power costs require 1,000-1,200 cf of gas per barrel of production, so the sensitivity to gas prices is around $1.25-1.50 per $1.00/m Btu. Requirements for steam injection average 2.5-3.0 barrels of steam per barrel of bitumen production. During project start-up, which lasts up to one year, steam requirements are much higher.

Overall operating costs average $10-15/b, with gas costs of $4.00-5.00/m Btu. *In situ* projects are sensitive to gas prices, but as long as light-crude prices maintain their Btu relationship to gas, and based on historical average light- versus heavy-crude prices, the rate of return on *in situ* projects rises with increases in crude prices.

Canada produces over 2.5m b/d of crude and exports 1.5m b/d to the US. Over 85% of Western Canada's crude exports are shipped to the US Midwest. The dominance of the Midwest market as a buyer of Canadian crude, especially heavy oil, means that based on existing pipeline routes and capacity, growth in bitumen production would be highly dependent on the region's refineries installing greater conversion capacity to process heavy crude.

In 2006, two pipeline reversals opened new markets for Canadian crude: the Spearhead pipeline is a reversal of a route from Cushing to Chicago; and the Corsicana pipeline runs from Chicago to the US Gulf Coast, which has the world's largest heavy-oil refining capacity. And two new pipelines are proposed: from Edmonton to the Gulf Coast; and from Edmonton to Kitimat, British Columbia – a deep-water port that would enable the largest of oil tankers to carry crude to southern California and Asia, in particular China.

Proposed projects for surface mining and *in situ* oil-sands development have mushroomed in the heated market for crude supply. If world crude prices are no longer a restraint on the size and quantity of oil-sands projects, then physical and financial constraints are the key factors which will govern the rate of growth.

CCS: research is not enough

Governments and industry face a dilemma: how to reconcile increased energy demand with the need to reduce atmospheric CO_2 concentrations. Carbon capture and storage (CCS) offers a means of reducing pollution from coal-fired power generation. By Jennie C Stephens, assistant professor of environmental science and policy, Clark University, Worcester, MA, US

Jennie C Stephens

The effect and future risks of climate change are becoming more apparent. Yet the atmospheric concentration of CO_2 continues to rise – the result of increased burning of fossil fuels. Achieving the magnitude of emissions reductions required for CO_2 stabilisation seems increasingly unlikely without carbon capture and storage technologies.

Interest in CCS has been strengthened by dramatic rises in oil and gas prices. Coal could be used as a substitute fuel, but coal-fired power generation emits more CO_2 per unit of energy than any other power-generating source. Deployment of CCS technology is essential to reconciling the sustained use of coal in a carbon-constrained world. Recognising that CCS is an integral part of clean-coal technology, interest and investment in CCS has grown rapidly over the past 10 years.

The CCS concept has evolved over 20 years, from a relatively obscure idea to an increasingly important set of energy technologies with unique potential for climate-change mitigation. CCS technologies, even if widely deployed, cannot solve the climate-change problem. But as society gradually shifts away from a fossil fuel-based energy infrastructure to an alternative energy system, CCS technologies have great potential to reduce CO_2 emissions before an energy transition is complete.

CCS should be considered among a portfolio of energy-technology changes that must be implemented, including: increased use of renewable energy sources; a shift to low-carbon-emitting, or no-carbon-emitting fuels; reductions in other non-CO_2 greenhouse gases; enhancement of biological uptake of CO_2; and, perhaps, an increase in nuclear power generation.

Growing interest

The term CCS incorporates a variety of technologies associated with capturing CO_2 from power plants and storing it in naturally occurring, underground geologic reservoirs. As interest and investment in developing and demonstrating CCS technologies has grown, belief in the technical feasibility of the approach has strengthened. Risks and safety concerns have been minimised. Further advancement of CCS technologies is not limited by technical obstacles, but by a lack of clear regulations that provide economic incentives for investment.

A CCS system relies on three sets of technological components: capture, transport and storage. Capture technologies are available and used commercially in ammonia production and other industrial manufacturing processes, as well as in oil refining and gas processing. CO_2 has been transported through pipelines and injected underground for decades, most notably in West Texas where it is used for enhanced oil recovery (EOR) at oil wells with declining production. Some 3m-4m tonnes a year (t/y) of CO_2 are successfully stored underground at several locations, including the North Sea, Canada and Algeria.

The integration and scaling-up of existing technologies to capture, compress, transport and store CO_2 emitted from a full-scale power plant have not yet been demonstrated. Advancing CCS technologies requires increased investment in large-scale demonstration projects as well as regulatory support for early opportunities for deployment.

CO_2 capture technologies associated with power plants can be divided into three categories:

- **Post-combustion CO_2 capture** – could be installed on existing, conventional coal-fired, coal-combustion power plants retrofitted to capture CO_2. Existing methods rely primarily on the chemical absorption of the CO_2 in a solvent (commonly amines). Although amine scrubbing to separate CO_2 from dilute gas streams is a widely used process in several industrial applications, the process has not been demonstrated on a commercial power plant. Post-combustion capture using chemical absorption is expensive – estimated to account for up to 80% of some overall predicted costs of a CCS system. The development of advanced methods of post-combustion capture that could reduce costs (including membranes and adsorption onto solids) is a critical research and development (R&D) goal;

- **Pre-combustion CO_2 capture** – CO_2 is separated from the gaseous fuel before the fuel is burned. The primary available technology relies on physical absorption of the CO_2 onto a solvent. It is more efficient and less expensive than post-combustion capture because of the higher percentage of carbon in gaseous fuels before they are burned compared with post-combustion emissions. Pre-combustion CO_2 capture is relevant only for gaseous fuel, so for this technology to be used with coal-fired power plants the coal must first be gasified. Integrated-gasification combined-cycle (IGCC) generation, in which the coal is gasified before being burned, allows CO_2 to be captured at a lower cost than in conventional pulverised coal plants. R&D is focusing on developing novel reactor concepts and new adsorption and absorption processes. Although the technology is used in small-scale applications, it has not been demonstrated on a commercial-scale power plant; and

- **Oxyfuel combustion** – introducing oxygen instead of air during combustion, is another approach to capturing CO_2 in coal-fired power plants because this produces a relatively pure stream of CO_2 in the emissions. This approach is considered by some to be the best option for retrofitting pulverised-coal power plants, but the costs are high and oxyfuel combustion has not been demonstrated on a large-scale power plant.

Once the CO_2 is separated and captured, it is compressed. This reduces the volume of the gas to allow for transportation to storage. Compressing gas is energy intensive. This part of the CO_2-capture system adds significantly to the overall operating costs and is also a contributor to the overall energy penalty associated with CCS.

After capture, compressed CO_2 is transported to storage. The large volumes of CO_2 that would need to be transported in a CCS system limit transportation options to pipelines or, possibly, ships. Building CO_2 pipelines poses no technical or safety

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challenges, although regional siting limitations are possible. Transportation by ship is an established option that could be important if long distances or challenging geography preclude the pipeline option.

The injection of CO_2 into naturally occurring geologic formations that provide underground reservoirs is the most promising storage option. Several types of geologic formations can be used for CO_2 storage, including depleted oil and gas reservoirs, unminable coal seams and deep saline aquifers. The oil industry's EOR projects provide commercial experience of injecting CO_2 underground.

CCS in practice

Interest in underground storage has been growing as both the private and public sectors have supported a handful of projects. At Sleipner, in the Norwegian North Sea, Statoil has been injecting CO_2 into a saline aquifer since 1996. At Weyburn in Saskatchewan, Canada, CO_2 has been injected underground since 2000 for the dual purpose of EOR and storage. And at In Salah in Algeria, BP began injecting CO_2 underground in 2004. In total, these and two smaller projects (Frio, in Texas, and a Dutch enhanced gas-recovery project) account for the successful storage of about 3m-4m t/y of CO_2.

Several other projects, of even greater scale, are planned in Australia, Germany and the US. Given the high degree of heterogeneity among different geologic formations, these first few projects do not yet provide sufficient experience representative of many other potential storage locations. Although some preliminary work has been done to understand the global distribution of appropriate reservoirs, their regional availability has not yet been well characterised – and this will be critical in determining the extent of CCS deployment around the world.

At Sleipner, in the Norwegian North Sea, Statoil has been injecting CO_2 into a saline aquifer since 1996. © Statoil

As well as storage in underground geologic formations, there has been interest in, and research into, injecting CO_2 into the deep oceans. Exploration of this approach is justified because the oceans have a natural capacity to store CO_2 emissions. But ocean uptake of atmospheric CO_2 is slow, so direct ocean injection is an attempt to accelerate a natural process, and strong public opposition has prevented R&D and demonstration projects. Some progress has been made, but the prospects for geologic storage are greater.

The risks and uncertainties associated with CCS are varied and, because of the novelty of the concept, public acceptance of these risks could be critical in determining the advancement and deployment of the technologies. A leakage from storage is the primary concern and a leak would undermine the purpose of the project. While much attention has been paid to improving understanding of these risks, continued research on the mobility of injected CO_2 and the risks associated with leakage is critical. The development and implementation of effective measurement, monitoring, and verification tools and procedures will also be critical in managing and minimising risks.

The countries that have invested the most in advancing CCS technology are, generally, those with rich fossil-fuel resources and a high level of established, long-term fossil-fuel reliance. The US, a coal-rich country with high energy demand, is investing in promoting and advancing CCS and so is Canada. In Europe, although coal reserves are small compared with those of the US and there are fewer oil and gas fields, governments have supported the advancement of CCS technology.

For the US, with its resurgent interest in the use of its coal reserves, CCS provides a way to reconcile increased coal use with climate-change mitigation. The government increasingly touts CCS as part of the future energy infrastructure. It supports a suite of CCS R&D programmes and has initiated a large-scale demonstration project, FutureGen. The primary goal of the R&D programme is to support technological developments that will reduce costs and a Regional Sequestration Partnership programme supports the development of region-specific research for determining the most suitable CCS technologies, regulations and infrastructure across the US.

The $1bn FutureGen project plans to be the first demonstration of a commercial-scale, coal-fired power plant with CCS technology. The goal is to establish technical feasibility and economic viability for integrating IGCC and CCS technologies. FutureGen has international support and involvement and if it progresses as planned it will be operational in 2015.

But although the US government is supporting CCS R&D and has initiated FutureGen, it has provided no regulatory incentives to encourage deployment. In Europe governments have supported the advancement of CCS technology in several ways. In 1996, Norway instituted a tax on CO_2 emissions, equivalent to around $50/t of CO_2, which motivated Statoil's Sleipner project. The EU is contributing funds to several CCS projects and the UK has supported CCS-related schemes.

Most developing countries have not begun to consider seriously the potential of CCS technologies as a climate-change mitigation strategy and government support for advancing the technologies is minimal or non-existent. However, the rapid expansion of energy infrastructure in many developing countries, particularly China and India, has created an immediate and urgent need to begin understanding potential CO_2-storage opportunities in developing countries.

Future advancement

The autumn 2005 release of the Intergovernmental Panel on Climate Change Special Report on CCS, the most comprehensive review of the status and potential of CCS, concludes that CCS has potential to reduce overall mitigation costs and increase flexibility in achieving CO_2-emissions reductions. But the widespread implementation of CCS depends on many factors, including: maturity and demonstration of the technology; costs; the regulatory framework; technology transfer to developing countries; environmental effects; and public perception.

Although the US has been among the leaders in initiating collaborative research and development efforts to advance CCS technologies, and CCS has become a critical component of the US government's strategy to confront climate change, the uncertain future of CO_2-emissions regulation in the US limits the rate of technological advancement of CCS technologies. Future advancement of CCS technologies is limited by the lack of clear CO_2 regulations to provide clear economic incentives for investing in the technologies, not by issues of technical feasibility.

A step in the right direction

The US' energy infrastructure will need major capital investment to meet future demand. But, before any construction can begin there will be a plethora of applications, permits and licences. By Branko Terzic, global regulatory policy leader, energy and resources, Deloitte Services

Throughout the US, aging energy-infrastructure facilities need to be replaced, capacity expanded and technology modernised. All this new capital investment can be made only with the regulatory approval of state and federal agencies.

The addition of energy infrastructure is subject to economic, design, location, cultural artifact, environmental and other regulatory permits issued by multiple state and federal agencies. Applicants and some consumers complain that this proliferation of regulatory approvals has led to unnecessary delays and increased costs of infrastructure addition, but recent federal law has taken some small steps to improve the situation in the electricity sector and for liquefied natural gas (LNG) terminals.

At state level, the regulation of infrastructure expansions is specific to the type of utility and property. Many states have individual laws covering power plant, electricity transmission or distribution infrastructure construction.

Individual state and federal laws designate as public-service or public-utility companies (the terms are interchangeable) private-sector companies providing electricity and gas services. These companies have traditionally been assigned a monopoly franchise to provide service to a geographic area, in return for which the rates for service and conditions of service are set by a regulatory agency – public-service commissions (PSC), or public-utility commissions, after the industries that they regulate. At the national level, the Federal Energy Regulatory Commission (Ferc) regulates the public utilities designated by federal law.

Individual states and the District of Columbia regulate retail electricity and gas distribution within their boundaries. Ferc regulates interstate gas pipelines, LNG terminals, the wholesale sale and transmission of electricity and certain hydro-electric plants. Public utilities also have state or federal government authority of eminent domain – the state can transfer authority to the public utility to condemn private property to enable construction of necessary infrastructure, a rarely used process.

The basic regulatory principle

Regulation is predominately based on the cost-of-service, or revenue-requirement principle. Also called rate-of-return regulation, the basic regulatory principle is that a public utility has the right to recover, in rates set by the regulator, an amount each year sufficient to meet operating expenses, depreciation expenses and taxes and still provide the opportunity of (but not guarantee) a return for investors. In setting rates, the regulator must establish the investment-rate base – to ensure investment can provide the level of service specified by regulation.

At the federal level, Ferc has authorised the use of a second method of determining rates, market-based pricing – a Supreme Court-approved alternative to Ferc's traditional cost-of-service methodology for wholesale power sales under its jurisdiction. Under market-based pricing, a seller of electricity can obtain a certificate to sell at market prices if it can demonstrate to Ferc that it does not have market power in the relevant wholesale market. Ferc retains full authority to re-impose regulated-rate setting in the form of rate caps or cost-of-service-based rates in the event of market failure.

Most PSCs establish a minimum threshold amount for capital projects over which the utility must apply to the PSC for pre-approval of the construction project. This is a very state-specific requirement. In Wisconsin, the threshold is $1m. In general, for an electricity utility, construction projects involving power plants, transmission lines, major sub-transmission lines, transmission sub-stations and distribution sub-stations are above the threshold and require pre-approval.

A few states do not have a pre-approval requirement and deal with issues of prudence of the investment, the need for the project and level of cost at the time of a rate-case application by the utility. The utility would build the facilities taking the risk that all or part of its construction expenditure could later be rejected by the PSC – at the time of the next rate case. Most utilities would provide the PSC with early information and cost justification for major projects, although a formal approval process is not required by law.

Establishing the need

In states where the PSC has pre-approval authority, the utility would have to apply for formal project approval in advance and request a Certificate of Approval for construction (CA) – in some state jurisdictions, and at Ferc, a Certificate of Public Convenience and Necessity (CPCN). The purpose of the CA/CPCN is to establish the need for the project, assess available alternatives, present the cost analysis and include any required environmental assessments.

Project construction may begin once a CA has been issued by the PSC. The certificate process may or may not involve the requirement for public notice – the process may require or warrant a public hearing before administrative law judges or, if the project is large or controversial, before the full commission.

In most states, electricity supply is provided by utilities with generation, transmission and distribution assets. Except in a few cases, California as the prime example, authorisation to construct new power plants rests with the PSC. In that case, the power plant CA contains the full economic, technical and reliability justification for the proposal. Ferc has no jurisdiction if the plant's output will supply the utility's native-load customers. Even in the case where some sales are made wholesale, requiring Ferc approval, only the power sold wholesale would fall under Ferc jurisdiction. Ferc has no authority to issue a CA and cannot grant eminent domain for a conventional power plant project.

An independent power plant (IPP) – also referred to as a merchant plant – is one not owned by an electricity utility. As in the case of utility-owned power plants, each state has established its own procedures for permitting construction.

Because IPP's sell power wholesale, they are subject to full-rate regulation by Ferc and usually apply for market-based rather than cost-of-service rates. However, state and local construction, environmental, water and land-use laws require permits from multiple state and local agencies. Under federal law, Ferc has authority only over plant economics, in terms of rate setting, and has subsequent authority to approve sales of existing power plants with approved Ferc tariffs.

Some states have special laws and siting agencies for power plants over a certain size – for example, the California Energy Commission has sole authority to license power plants of 50 megawatts (MW) and larger, as well as transmission lines carrying 50 MW or more in the state. Each state has its own energy-planning laws, environmental-protection requirements and specific authority and requirements concerning the location and construction of plants.

To date, all US nuclear plants have been built by investor-owned public utilities or government agencies. For utility-owned nuclear plants, economic approvals and certificates of authority have come from PSCs. Ferc has no construction authority, but has rate-setting authority for sales to the wholesale market. The US Nuclear Regulatory Commission (NRC) has exclusive jurisdiction over the licensing and regulation of civilian nuclear plants to protect public health and safety and maintain national security. The NRC issues standard design certifications, early site and construction permits, operating licences and combined licences for commercial nuclear facilities. The Energy Policy Act 2005 (EPA 2005) provides incentives, reduces risk and has created an expedited process for new nuclear-production approvals, including the issuance of a combined construction and operations licence.

The NRC can revoke licences, close plants and invoke fines for safety violations. Consequently, nuclear plants are jointly regulated by the state and federal governments, with the state PSC regulating economics and NRC regulating safety and operation.

Nuclear considerations

The Nuclear Energy Institute says nine nuclear projects are being considered. Three consortia, comprising 18 firms, are preparing nine combined-licence applications for 14 plants in nine southeast states. Four other companies are also evaluating the new nuclear option. The first submittals to the NRC should occur in 2007, with licence approvals expected in 2010. If this schedule is achieved, the US would have the first generation of these new nuclear power plants in operation by 2014-2015.

Ferc regulates non-federal construction and operation of hydro-electric projects on federal waterways. Four types of licence have been issued: less than three years; 50 years; and major and minor licences based on predicted horsepower. Most recently, Ferc has dealt with issues of re-licensing or recapture of the 50-year licences. Federal hydro-electric projects are not under Ferc jurisdiction and have their own federal enabling statutes.

Exclusive authority over approval of transmission-line construction was with PSCs until the passage of the EPA 2005, which gave Ferc authority to approve construction and federal eminent domain for qualifying proposals. Ferc can now authorise transmission lines routed in certain corridors where the expansion of transmission is deemed necessary for national security by the Department of Energy.

In all other cases, individual state laws continue to direct the state PSC or another designated agency to approve the siting/routing of transmission-line construction, whether for intrastate or inter-state purposes. In some states, the PSC has both site- and construction-approval authority. Applications for transmission-line construction follow regular CA procedures, as specified by state laws.

Some experts say it has become more difficult to build transmission facilities than individual power plants, because of the linear nature of power lines, which usually cross many political jurisdictions and the property of numerous land owners. Transmission lines also draw opposition over concerns, warranted or unwarranted, about electro-magnetic fields and aesthetics. A new development is the creation of independent transmission companies, which own transmission assets, but no generation of distribution facilities. Because such companies provide third-party access, their rates are fully regulated by Ferc.

A number of entities are designated as independent system operators (ISO) and regional transmission operators (RTO) – not-for-profit organisations that do not own transmission assets, but control the use of the member company's transmission system by dispatching power plants to maintain system balance. They also operate wholesale power markets. Not all electricity utilities have become members of an ISO or a larger RTO. Each ISO is regulated by Ferc and has specific rules concerning operation.

Transmission rates for all US entities are set by Ferc under cost-of-service methodology. Ferc has recently indicated that it would encourage transmission-capacity expansion by offering incentive rates and the EPA 2005 enables this.

Gas pipelines, storage and LNG

The interstate gas industry is subject to Ferc regulation – it has approval authority for construction of new interstate gas pipelines and storage systems, and LNG import facilities. Additionally, other approvals must be obtained from applicants wishing to build facilities.

Ferc uses cost-of-service methodology to establish pipeline service rates and requires the pre-approval of pipeline construction through a CPCN. Ferc is also the lead agency in issuing Environmental Impact Statements (EIS). Ferc's process requires the issuance of public notice and commensurate public hearings. Upon collection of the record, comments and filed materials, Ferc will issue Preliminary Determinations, Draft EIS, Final EIS and Certificate.

Some experts say it has become more difficult to build transmission facilities than power plants, because of the linear nature of power lines that usually cross many political jurisdictions and numerous land owners' property

A recent pipeline-construction applicant for a facility crossing two US states and into Canada cited the need for 603 environmental-filing requirements. Ferc issued 18 other official Notices to Proceed and the Canadian crossing required a US Presidential permit and US Presidential International Border Crossing Permit, as well as various Canadian permits. Other US agencies involved in the process of licensing an interstate pipeline can include: Army Corps of Engineers; Coast Guard; Department of Agriculture; Environmental Protection Agency; Fish and Wildlife Service; and The National Park Service.

At state level, gas-pipeline projects usually require permits or reviews by state environmental and land-use agencies, and local municipalities. These entities issue road-crossing, zoning-variances, soil and water conservation permits, and other special local permits. As in the case of electricity-transmission construction applications, local opposition can be based on environmental, aesthetic and safety concerns. The not-in-my-backyard syndrome, affects infrastructure proposals across the country.

Ferc regulates construction of underground gas-storage facilities. In a new and positive development for future construction, under the EPA 2005 Ferc has authority to extend market-based pricing to new storage capacity, even if the company is unable to demonstrate that it lacks market power.

The authority to construct LNG import or export facilities onshore lies with Ferc and its jurisdiction was clarified and improved by the EPA 2005. Ferc has "exclusive authority to approve or deny an application for the siting, construction, expansion and operation of an LNG terminal". But, states retain rights under various other acts, such as the Clean Water Act and the Clean Air Act, to deny approval for construction. To date, Ferc has acted on approvals for 12 LNG import terminals. The US Coast Guard has approved two offshore terminals.