Natural Gas Electricity Interface Review (NGEIR)

Summary of Gas Practices in Other Jurisdictions

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1 SUMMARY

This report reviews practices in selected other jurisdictions, namely: Alberta, United States (FERC, California, Illinois, Michigan and New York) and Great Britain, with respect to services provided to gas-fired generators as part of the Natural Gas Electricity Interface Review ("NGEIR") process that has been launched by the Ontario Energy Board. As such, the report assesses the activities of the different players pertinent to the natural gas/electricity interface including activities of regulators, policy makers, electricity system operators, pipelines/storage companies and other utilities. These activities in turn relate to the services provided to gas-fired generators by transmission/storage companies, decisions and rules of the different regulators with respect to the approval of the construction of the necessary facilities required to serve the power market's gas requirements and the cost allocation of the associated investment and also the energy policies and plans, if any, of governments in regard to gas-fired generation.

Alberta

In Alberta, gas-fired generation plays a significant and growing role in the electricity market, accounting for the second largest 40.2% of electricity generation in 2005; however, it faces stiff price competition from coal-fired stations due to the recent large increases in the price of natural gas.

Most of the major natural gas fired generating facilities purchase directly off the two major transmission pipeline systems, Nova Gas Transmission Limited ("NGTL"), or TransCanada's Alberta System, and ATCO Gas Pipeline. The two pipelines also have flexible nomination policies. ATCO's nomination timeframes, for example, vary with the service involved, but in most cases range from 4 to 5 hours. Similarly, NGTL's nomination policy and procedures indicate that there are five nomination cycles each day during non-critical conditions and two during critical conditions.

NGTL's charges related to the cost of additional facilities necessary to attach a customer to its system are set out in its Rate Schedule for Facilities Connection Service and under the terms of this rate schedule, the cost to the customer is zero as long as it maintains a specified level of throughput volume.

The significant storage capability within the province of Alberta also helps to provide the gas supply flexibility that facilitates natural gas fired generation. EnCana Gas Storage operates the AECO Hub and its rates are market-based and its tariff offers flexibility in the form of a multi-time nomination schedule with intra-day nominations and the possibility of multiple storage cycles.

United States

FERC's rules with respect to the certification of new interstate natural gas pipelines and storage facilities, the cost allocation thereof and also its policies with respect to access to gas transportation services provides the main framework under which the interstate pipelines operate in the four U.S. jurisdictions under consideration (California, Michigan, Illinois and New York).

Before FERC's Statement of Policy (PL99-3-000) on Certification of New Interstate Natural Gas Pipeline Facilities was issued in September of 1999, its certification policy required an applicant to submit a contractual commitment for at least 25 percent of the capacity. Moreover, the Commission applied a presumption in favour of rolled-in rates when the cost impact of the new facilities would result in a rate impact on existing customers of five percent or less and some system benefits would occur. Existing customers generally would bear these rate increases without being allowed to adjust their volumes.

The 1999 Statement of Policy, on the other hand, established that, when a certificate application is filed, the threshold question applicable to existing pipelines is whether the project can proceed without subsidies from their existing customers. This usually means that the project would be incrementally priced, but there are cases where costs can be rolled-in, when for example, the project is designed to improve existing service for existing customers. Rates for independent storage can be at cost-of-service or market-based, depending on whether FERC finds that the storage operator can exercise market power. Pipelines also can seek market-based rates under the same terms.

In addition, FERC's Order 636, which was issued in 1992, has been of great significance in terms of access to transportation capacity. It requires pipeline companies to provide a mechanism for the resale of pipeline capacity that is held by firm customers or shippers on a pipeline's system. This mechanism, known as Capacity Release allows shippers to buy, sell or trade firm capacity on a host pipeline without the pipeline's involvement in the transaction. Any shipper with a firm transportation contract authorized under a blanket authorization can remarket transportation capacity, usually to the highest bidder who can be end users, producers selling and delivering gas directly to customers or marketers buying gas at one location and selling it at another.

The counterparties are free to set the terms and conditions, as long as they are not unduly discriminatory or preferential and the cost does not exceed the applicable maximum rate (which is the maximum firm transportation rate).

In the four States under consideration-California, Illinois, Michigan and New York- gas-fired generation is a significant source of electric power accounting for, 44.7% (2002), 27% (2003), 25% (2002), and 25% (2005, accounting for dual fired generation) respectively of the total electric industry's generating capability.

In all the four States, the jurisdictional policy with respect to the allocation of cost of investment on new intrastate gas infrastructure is that such costs could either be rolled-in or incremental depending on individual circumstances. For interstate gas infrastructure, the FERC rules on cost allocation discussed above apply.

Major natural gas fired generating facilities purchase directly off the major transmission pipeline systems. In California, for example, some large noncore customers, that include gas-fired generators, take natural gas directly off the high-pressure backbone pipeline systems of PG&E and SoCalGas, while core customers and other noncore customers take natural gas off the utilities' distribution pipeline systems.

Most pipelines and storage companies in the four States provide a variety of flexible, some more than others, services that are either specifically designed for gas-fired generators or that which the latter would in general find attractive. These include flexible nomination cycles, flexible storage inventory, injection, and withdrawal services and lending & parking services

Given that the four States have been increasingly relying on natural gas for electricity generation, recent developments in the natural gas market have raised some concerns for governments, regulators, system operators, and others in the States. Many of them have conducted studies or have come up with policies and plans to address the problem. One study commissioned by the New York ISO in 2002, for example, has concluded that it continues to be critical for generators to have the ability to burn oil even when gas supplies are adequate; oil storage should also be preserved to assure future reliability of the electrical system when gas cannot be delivered. Another study has identified the decisions of gas-fired generators to purchase non-firm gas transportation service and to not invest in dual-fuel capability in the Northeast region as one major problem. NERC has formed a task force, called the Gas/Electricity Interdependency Task Force (GEITF), to evaluate the interdependency between gas pipeline operation/planning, and electric system operation/planning reliability over a ten-year time horizon.

Great Britain

Electricity generation in Great Britain has been relying less and less on coal over the years and has become more diverse with an increasing emphasis on natural gas and renewable sources. In 2005, almost 40% of the electricity generated came from gas-fired generators.

Large volume customers in Great Britain can either take service directly off the National Transmission Service (NTS) or from the distribution systems of the LDCs. Parties wishing to ship gas on the NTS must first obtain a licence from the energy regulator- the Office of Gas and Electricity Markets ("Ofgem"). Transmission operators are expected to do business with any shipper that has obtained a licence from Ofgem as long as it meets the necessary financial requirements.

In 2002, Lattice Group plc, the holding company for Transco which was the owner and operator of the natural gas transmission system in England and Wales, and National Grid Group plc, which owned and operated the electricity transmission and distribution system in the same area, merged under the name National Grid Transco plc ("National Grid"). This has facilitated some high level co-ordination between the two markets.

One of the problems facing gas-fired generation in Great Britain today is the government's policy that has supported and provided financial incentives for renewable sources of power. This policy combined with rising natural gas prices, has resulted in a significant increase in the development of wind.

2 ALBERTA

2.1 OVERVIEW OF THE ENERGY MARKET

The electricity market in Alberta exhibits many characteristics that are extremely favourable to generators of almost all descriptions but particularly those with natural gas or coal fired facilities where the fuel sources are readily available. However, the market is also extremely competitive. The market has been fully unbundled and is operated by the independent Alberta Electric System Operator ("AESO"). The government and regulatory authorities are largely not intrusive and are supportive of open markets. The opening of the electricity market to competition began in 1996. The deregulation process for the natural gas market commenced in the mid-1980's and was largely completed in 2003 when marketers were allowed to offer service to customers of the province's large distribution utilities, including residential customers.

The following data for the 2003 electricity market, the latest year for which data was available, was taken from the website of the Alberta Department of Energy ("ADE").

Market Segment	2003 Number of Customers	2003 Usage (GWh)
Residential	1,086,927	7,581.0
Farm	78,986	1,776.1
Commercial	140,537	11,117.8
Industrial	37,363	27,869.0
Total	**1,343,813**	**48,344.6**

Source: Alberta Department of Energy

In addition to being a significant producer of natural gas, Alberta also produces large amounts of low sulphur coal. According to data posted to the ADE website, Alberta has 33.6 Gigatonnes of proven coal reserves which represent 60 per cent of the total for Canada as a whole. In 2003, Alberta produced 30 million tones of coal of which 25 million tonnes (about 83%) was used in electricity generation.

2.2 OVERVIEW OF THE GAS MARKET

According to the ADE website, in 2003 Alberta had 200 trillion cubic feet ("Tcf") of remaining ultimate potential reserves of natural gas. During that year, the province produced 4.99 Tcf of natural gas, of which just over 2.6 Tcf was exported to the U.S and just over 1 Tcf was sent to other parts of Canada. This large volume of natural gas production, augmented by significant storage facilities, has resulted in an extremely liquid market in Alberta. Natural gas is effectively almost always available and most natural gas fired generating plants purchase on the spot market. The market is so liquid that customers willing to take the price risk can draw some gas from the pipeline, effectively using its line-pack as a form of storage, and purchase make-up gas the following day without fear of not acquiring the gas that it needs. This "yesterday" market effectively trades the same as spot.

2.3 State of Gas Generation

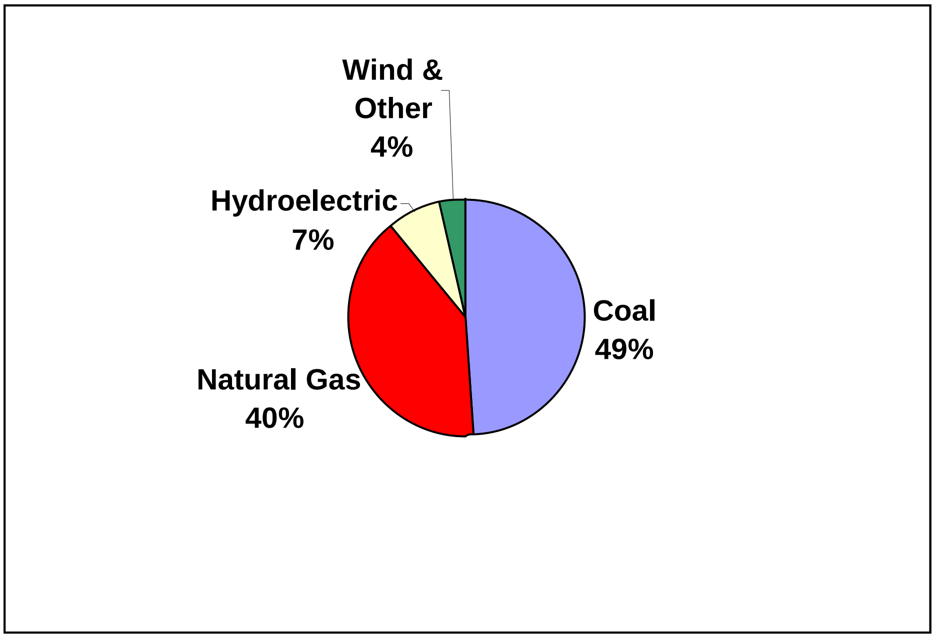
Natural gas-fired generation plays a significant and growing role in the Alberta electricity market but faces stiff price competition from "mine-mouth" coal-fired stations. The large increases in the price of natural gas have led to the competitiveness of electricity sourced from that fuel being significantly challenged. This appears to be reflected in the operations of the electricity market where coal-fired plants, on average, operate at much higher load-factors than do the natural gas fired plants. Table 1 and Figure 1 provide a breakdown of Alberta's generation capacity by fuel source in May of 2005.

2.3.1 Table 1: Generation Sources for Alberta Electricity Market – May 2005

Source	**Capacity** (MW)	**Proportion of Market** (%)
Coal	5,840	48.9
Natural Gas	4,802	40.2
Hydraulic	869	7.3
Wind and Other	429	3.6
Total	**11,940**	**100.0**

Source: Alberta Department of Energy

2.3.2 FIGURE 1. GENERATION SOURCES FOR ALBERTA ELECTRICITY MARKET – MAY 2005



The market also has interconnections with British Columbia (with a capability of 800 MW) and Saskatchewan (with a capability of 150 MW), respectively. According to the Government of Alberta's web site, since 1998 more than 3,800 MW of additional generating facilities have been built. This includes approximately 2,400 MW of natural gas-fired cogeneration facilities along with 450 MW of coal-fired and nearly 250 MW of wind-powered generation. The website also indicates that proposals have been made which contemplate an additional 4,300 MW of generation over the 2005 to 2010 period. Of these proposals approximately 1,572 MW are natural gas fired and another 1,640 MW are coal fired.

2.4 SERVICES

Most of the major natural gas fired generating facilities purchase directly off the two major transmission pipeline systems, Nova Gas Transmission Limited ("NGTL"), or TransCanada's Alberta System, and ATCO Gas Pipeline. Both of these pipeline systems have tariffs which help facilitate the operation of power plants by allowing for intra-day nominations. New customers connecting to the pipelines are not subject to incremental facilities costs as long as they continue to meet contractual requirements with respect to minimum terms of service and minimum annual throughput volumes. Both are regulated by the Alberta Energy and Utilities Board.

ATCO Pipelines

The ATCO Pipelines ("AP") Transmission Transportation Business Policy & Practices ("TTBPP") sets out its policies with respect to investment in facilities and its nomination practices. The level of investment in the facilities AP is willing to make in order to provide service to a customer is a function of the contract term the customer is willing to agree to. Customers that are not willing to agree to the required term must either make a capital contribution or pay a Specific Facility cost of service charge.

ATCO's nomination policy would appear to be very flexible. The timeframes for nominations set out in its TTBPP vary according to the service involved but in most instances range from 4 to 5 hours. This applies to nominations involving ATCO and/or NGTL interconnections, those related to transfers to another customers account and ATCO's Exchange Service. The exceptions are those involving unmanned on-system Points of Receipt or Delivery where the notice is specified by the system operator.

Nova Gas Transmission Ltd

NGTL's charges related to the cost of additional facilities necessary to attach a customer to its system are set out in its Rate Schedule for Facilities Connection Service. Under the terms of this rate schedule, the cost to the customer is zero as long as it maintains a specified level of throughput volume.

NGTL's nomination policy is similar to that of ATCO. According to the operational procedures set out on the website for TransCanada's Alberta System, there are five nomination cycles each day during non-critical conditions and two during critical conditions. The deadline for nominations in critical conditions is 5 hours in advance of the flow of gas while it is 4 hours in non-critical conditions.

2.5 STORAGE

The significant storage capability within the Province of Alberta also helps to provide the gas supply flexibility that facilitates natural gas fired generation. There is about 238 billion cubic feet ('Bcf") of storage in Alberta.

EnCana Gas Storage operates the AECO Hub which is comprised of three storage sites with a total capacity of about 105 Bcf. EnCana's rates are market-based and its tariff offers flexibility in the form of a multi-time nomination schedule with intra-day nominations and the possibility of multiple storage cycles.

Another large storage facility is ATCO Midstream's 40 Bcf Carbon Storage Facility. Operated as a component of ATCO Midstream's Alberta Market Centre hub service, the Carbon Storage Facility also offers both multi-cycling and intra-day nominations. Although the facilities are currently reflected in the rate base of the ATCO Midstream's regulated affiliate, ATCO Gas, the entire capacity is leased to ATCO midstream and it charges market-based rates for its services.

BP, Husky and Alberta Hub own and operate gas storage of 40, 35 and 15 Bcf respectively.

2.6 JURISDICTIONAL POLICY

The restructuring of the Alberta electricity market began in 1996 when legislation came into effect and opened the supply of electricity to competition. The previously vertically integrated industry was unbundled with the transmission and distribution sectors continuing to be regulated by the Alberta Energy and Utilities Board but with the market setting the price for generation. Prior to this restructuring, the generation sector was dominated by three major players: TransAlta Utilities Corporation; Edmonton Power Corporation, now EPCOR; and Alberta Power, now known as ATCO Electric. In order to facilitate a more competitive market, the Alberta Government directed that the output from these utilities' existing generating facilities be auctioned off in the form of Power Purchase Arrangements ("PPAs"). The utilities retain ownership of the facilities but the successful bidders control the dispatching of the output. Generating facilities which were constructed after January 1, 1996 were not subject to this process. Two such auctions were held in 2000.

2.7 RECENT DEVELOPMENTS

In June of 2005, the ADE released a report entitled "Alberta's Electricity Policy Framework: Competitive-Reliable-Sustainable" The report reaffirms the provincial government's intent to maintain and support a competitive electricity market and articulates a vision which includes creating the right conditions to facilitate an electric industry which is competitive, reliable and sustainable. To achieve this vision, public policy must be developed and implemented in a manner which is balanced and adaptable so investors have confidence that the market is fair, and consumers have confidence that electricity is reliable and reasonably priced. The paper also sets out the ADE's preferred options for addressing several of the issues related to the electricity market. With respect to retail market design, it recommended that there be a transitional Regulated Rate Option ("RRO") rate design for the small consumer market. During the 2005-2010 period these consumers would pay a blended rate that would reflect a gradual reduction in the proportion based on long-tem forward hedges and a corresponding increase in the proportion based upon monthly forward hedges. The intent is that, at the end of the transition period in 2010, the new Regulated Rate Option would be based on a monthly forward hedge similar to the design of the current natural gas default rate which is based on the monthly forward natural gas price.

With respect to short-term adequacy, the ADE recommends a number of refinements to the wholesale market structure that it says will improve supply visibility and stability for the ISO and thereby enhance system reliability and price fidelity. With respect to long-term adequacy, the ADE points out that the competitive generation market has been successful in attracting over 3,500 MW of new generation capacity since 1998. It is not recommending the introduction of capacity-based contractual obligations at this time. The ADE has indicated that it will work with the ISO and stakeholders to implement a robust and effective monitoring system to ensure that all market participants understand the reserve margin and overall state of capacity adequacy in the province. Specific metrics will be established to monitor timing, location and system impact status of new generation additions using information such as permits, construction progress reports and public announcements. Stakeholders will be consulted on the specific rules and procedures for implementing this measure. The ADE goes on to say that transmission developments will also be monitored and factored into the adequacy measure. If the monitoring process produces a clear signal that there is a likely adequacy shortfall, the ISO will have direction to ensure adequacy is maintained.

The paper also addresses a number of other issues including:

- Operating reserves market
- Transmission must run services
- The treatment of energy offered over interties
- Demand response
- The future of balancing pool assets
- The credit implications of policy recommendations
- Market power mitigation
- The integration of wind generation

On July 22, 2005 the ADE issued a document entitled "Draft Market Performance Metrics Report: An Alberta Department of Energy Report and Discussion Paper" In this report the ADE sets out, for the purposes of discussion, comments on metrics which had previously been identified as those that should be monitored regularly in order to measure the development of a competitive electricity market. It also provides the data collected for each month pilot tested for the period January to June 2005. The metrics were:

- Number of retailers
- Product offering diversity
- The rate of customer switching
- Market concentration
- Retailer's profit margin

The ADE has indicated that, based on the pilot test, it plans to continue to collect the necessary data and present these metrics at least annually. The ADE expects that, in the beginning, it will be necessary to make some adjustments and refinements to the calculation of the metrics. It has also undertaken to attempt to construct the metrics back through time, where data is available, in order to track the development over a longer time period.

3 FEDERAL ENERGY REGULATORY COMMISSION (FERC)

The Federal Energy Regulatory Commission ("Commission" or "FERC") regulates the interstate transmission of electricity, natural gas, and oil in the United States. FERC also reviews proposals to build liquefied natural gas ("LNG") terminals and interstate natural gas pipelines as well as licensing hydropower projects.

The relevance of FERC's role in the natural gas/electricity interface lies in its jurisdictional policy relating to the certification of new interstate natural gas pipelines and storage and the cost allocation thereof and also the services and standards it expects of pipelines as established mainly by the Commission's Order 636 issued in 1992.

3.1 JURISDICTIONAL POLICY

3.1.1 CERTIFICATION OF NEW INTERSTATE NATURAL GAS PIPELINE FACILITIES

1) PRE-1999 POLICY

Before its 1999 Statement of Policy ("PL99-3-000")[1], the Commission would reach a final determination on whether a project met the public convenience and necessity standard by performing a balancing process during which it weighted factors presented in a particular application. Among the factors that the Commission considered in the balancing process were the proposal's market support, economic, operational, and competitive benefits, and environmental impact.

Under the Commission's then existing certificate policy, an applicant seeking a certificate of public convenience and necessity to construct a new pipeline project was required to show market support through contractual commitments for at least 25 percent of the capacity for the application to be processed by the Commission. An applicant showing 10-year firm commitments for all of its capacity, and/or demonstrating that revenues would exceed costs was eligible to receive a traditional certificate of public convenience and necessity.

If the applicant was unable to show the required level of commitment, it could still have received a certificate but it would have been subject to a condition putting the applicant "at risk." In other words, if the project revenues failed to recover the costs, the pipeline rather than its customers would have been responsible for the unrecovered costs. Also, a project sponsor could have applied for what was referred to as 'optional certificate', which may have been granted to an applicant without any market showing at all, even though in practice optional certificate applicants usually made some form of market showing. The rates for service provided through facilities constructed pursuant to an optional certificate were designed to impose the economic

[1] Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy, 88 FERC ¶ 61,227, 61,746, (1999).

risk of the project entirely on the applicant.

The Commission also would certify projects that did not serve new markets, but did provide some demonstrated system-benefits such as improved system reliability, access to new supplies, or more economic operations.

Pricing policy:

Under its pricing policy for new facilities adopted, in Docket No. PL94-4-000[2], the Commission also determined, in certificate proceedings authorizing the construction of facilities before its 1999 change in policy, the appropriate pricing for the facilities. Generally, the Commission applied a presumption in favour of rolled-in rates (rolling-in the expansion costs with the existing facilities' costs) when the cost impact of the new facilities would result in a rate impact on existing customers of five percent or less, and some system benefits would occur. Existing customers generally bear these rate increases without being allowed to adjust their volumes.

When a pipeline proposed to charge a cost-based incremental rate (establishing separate-cost-of-service and separate rates for the existing and expansion facilities) that was higher than its existing generally applicable rates, the Commission would usually approve the proposal. The Commission generally would not accept a proposed incremental rate that was lower than the pipeline's existing generally applicable rate.

Drawbacks of the Pre-1999 Policy

FERC subsequently started exploring issues relating to the existing policies on the certification and pricing of new construction projects in view of the changes that were taking place in the natural gas industry. On June 7, 1999, the Commission held a public conference in Docket No. PL99-2-000 on the issue of anticipated natural gas demand in the Northeastern United States over the following two decades, the timing and type of growth, and the effect the projected growth would have on the existing pipeline capacity. All segments of the industry presented their views at the conference and subsequently filed their comments with the Commission. The result was that the Commission identified the following drawbacks of the then existing policies:

a. Reliance on Contracts to Demonstrate Demand

The Commission concluded that the use of percentage of capacity under long-term contracts as the only measure of the demand for a proposed project was too narrow a test because, firstly, it doesn't test other public benefits such as the environmental advantage of gas over other fuels, lower fuel costs, access to new supply sources or the connection of new supply to the interstate grid, the elimination of pipeline facility constraints, better service from access to competitive transportation options, and the need for an adequate pipeline infrastructure. Secondly, it was not a sufficient indicator by itself of the need for a project, because the industry had been moving to a practice of relying on short-term contracts, and pipeline capacity is often managed by an entity that is not the actual purchaser of the gas. Using contracts as the primary indicator of market support for the proposed pipeline project would also raise additional issues when the contracts are held by pipeline affiliates. The Commission also noted that the policy's preference for contracts with 10-year terms biases customer choices toward longer term contracts.

[2] See Pricing Policy for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines, 71 FERC P61,241 (1995)

Eliminating a specific requirement for a contract of a particular length would be more consistent with the Commission's regulatory objective to provide appropriate incentives for efficient customer choices and the optimal level of construction, without biasing those choices through regulatory policies.

Finally, FERC noted that by relying almost exclusively on contract standards to establish the market need for a new project, the policy made it difficult to articulate to landowners and community interests why their land must be used for a new pipeline project.

b. The Pricing of New Facilities

The Commission noted that the then pricing policy focused primarily on the interests of the expanding pipeline and its existing and new shippers, giving little weight to the interests of competing pipelines or their captive customers. It also stated that the pricing policy sent the wrong price signals by masking the real cost of expansions which could result in overbuilding of capacity and subsidization of incumbent pipelines when competing with potential new entrants for expanding markets. Moreover, the pricing policy's bias for rolled-in pricing was also inconsistent with a policy that encourages competition while seeking to provide incentives for the optimal level of construction and customer choice. The Commission explained that rolled-in pricing often resulted in projects that were subsidized by existing ratepayers. Under this policy, the true costs of the project would not be seen by the market or the new customers, leading to inefficient investment and contracting decisions.

Finally, the Commission noted that under existing policy, shippers' rates may change for a number of reasons including the rolling-in of expansion costs, changes in the discounts given to other customers, or changes in the contract quantities flowing on the system. As a customer's rates change in a rate case, it is generally unable to change its volumes, even though it may be paying more for capacity. This would result in shippers bearing substantial risks of rate changes which they may be ill equipped to bear.

2) THE NEW POLICY (1999)

On September 15, 1999, FERC issued its Statement of Policy ("PL99-3-000") on Certification of New Interstate Natural Gas Pipeline Facilities.

a. Summary of the Policy

When a certificate application is filed, the threshold question applicable to existing pipelines is whether the project can proceed without subsidies from their existing customers. This will usually mean that the project would be incrementally priced, but there are cases where rolled-in pricing would prevent subsidization of the project by the existing customers. If the project cannot be built without subsidies, the Commission will deny the application.

The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the existing customers of the pipeline proposing the project, existing pipelines in the market and their captive customers, or landowners and communities affected by the route of the new pipeline. This is not intended to be a decisional step in the process for the Commission, it is rather a point where the Commission will review the efforts made by the applicant and could assist the applicant in finding ways to mitigate the effects.

If the proposed project does not have any adverse effect on the existing customers of the expanding pipeline, existing pipelines in the market and their captive customers, or the economic interests of landowners and communities affected by the route of the new pipeline, then no balancing of benefits against adverse effects would be necessary. The Commission would proceed to a preliminary determination or a final order depending on the time required for completing an environmental assessment (EA) or environmental impact statement (EIS) (whichever is required in the case).

If residual adverse effects on the above mentioned three interests are identified, after efforts have been made to minimize them, then the Commission will proceed to evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. Only when the benefits outweigh the adverse effects on economic interests will the Commission then proceed to complete the environmental analysis where other interests are considered. It is possible at this stage for the Commission to identify conditions that it could impose on the certificate that would further minimize or eliminate adverse impacts and take those into account in balancing the benefits against the adverse effects. If the result of the balancing is a conclusion that the public benefits outweigh the adverse effects then the next steps would be the same as for a project that had no adverse effects. That is, if the EA or EIS would take more than approximately 180 days to complete then a preliminary determination could be issued, followed by the EA or EIS and the final order. If the EA would take less time, then it would be combined with the final order.

b. The Threshold Requirement –No Financial Subsidies

The threshold requirement in establishing the public convenience and necessity for existing pipelines proposing an expansion project is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers[3]. This doesn't mean that the project sponsor has to bear all the financial risk of the project; the risk can be shared with the new customers in preconstruction contracts, but it cannot be shifted to existing customers. For new pipeline companies, without existing customers, this requirement will have no application.

This requirement that the project must be able to stand on its own financially without subsidies changed the old pricing policy, which had the presumption in favour of rolled-in pricing. The Commission concluded that eliminating the subsidization usually inherent in rolled-in rates

[3] FERC explains that projects designed to improve existing service for existing customers, by replacing existing capacity, improving reliability or providing flexibility are for the benefit of existing customers. Increasing the rates for existing customers to pay for these improvements is not a subsidy. Under the existing policy, these kinds of projects are permitted to be rolled-in and are not covered by the presumption of the current pricing policy.

through a policy of incremental pricing would send the proper price signals to the market. With a policy of incremental pricing, the market will then decide whether a project is financially viable.

The Commission also pointed out that the new requirement helps to address all of the interests that could be adversely affected. For example, existing customers of the expanding pipeline should not have to subsidize a project that doesn't serve them. Landowners shouldn't be subjected to projects that are not financially viable and therefore may not be viable in the marketplace. Existing pipelines should not have to compete against new entrants into their markets whose projects receive a financial subsidy (via rolled-in rates), and neither should a pipeline's captive customers have to shoulder the costs of unused capacity that results from competing projects that are not financially viable.

The Commission made it clear that, while new projects must be financially viable without subsidies, this requirement does not eliminate the possibility that in some instances the project costs should be rolled into the rates of existing customers. In most instances incremental pricing will avoid subsidies for the new project, but the situation may be different in cases of inexpensive expansibility that is made possible because of earlier, costly construction. In that instance, because the existing customers bear the cost of the earlier, more costly construction in their rates, incremental pricing could result in the new customers receiving a subsidy from the existing customers because the new customers would not face the full cost of the construction that makes their new service possible. The issue of the rate treatment for such cheap expansibility, the Commission points out, is one that always should be resolved in advance, before the construction of the pipeline.

Another instance where a form of rolling in would be appropriate according to FERC is where a pipeline has vintages of capacity and thus charges shippers different prices for the same service under incremental pricing, and some customers have the right of first refusal ("ROFR") to renew their expiring contracts. Those customers could be allowed to exercise a ROFR at their original contract rate except when the incremental capacity is fully subscribed and there are competing bids for an existing customer's capacity. In that case, an existing customer could be required to match the highest competing bid up to a maximum rate which could be either an incremental rate or a "rolled-up rate" in which costs for expansions are accumulated to yield an average expansion rate.

Under this policy, the pipeline bears the risk for any new capacity that is under-utilized, unless it contracts with new customers to share that risk by specifying what will happen to rates and volumes under specific circumstances. If the pipeline finds that new shippers are unwilling to share this risk, this may indicate to the pipeline that others do not share its vision of future demand. Similarly, the risks of construction cost over-runs should not be the responsibility of the pipeline's existing customers but should be apportioned between the pipeline and the new customers in their service contracts. Thus, in pipeline contracts for service on newly constructed facilities, pipelines should reach agreement with new shippers concerning who will bear the risks of underutilization of capacity and cost overruns and the rate treatment for "cheap expansibility."

3.1.2 Storage

Storage operators (independent or pipeline affiliated) offering services in interstate commerce must receive a certificate of public convenience and necessity from FERC to construct and operate storage facilities.

Rates for independent storage can be at cost-of-service or market-based, depending on whether FERC finds that the storage operator can exercise market power. Pipelines can also seek market-based rates under the same terms. In 1996 FERC issued its Alternative Rate Policy Statement which provided the framework for evaluating market-based rate proposals. Market power is determined in terms of whether the storage operator can withhold or restrict services and thereafter increase price by a significant amount for a significant period of time; and whether the storage operator can discriminate unduly in price or terms and conditions. The market power test has three elements:

1) define the relevant market;
2) measure the market share and market concentration; and
3) evaluate other relevant factors.

Applicants need to satisfy the FERC in these three areas in their requests for market-based rates.

Often, new independent storages services need additional pipeline capacity expansion in order to feed the storage facility and make it available during peak demand hours. As noted earlier, incremental additions to pipeline capacity to accommodate new customers are usually priced at the incremental cost-of-service, unless the FERC is satisfied that the new service benefits existing customers and the cost impact on the latter is not significant. Whether the pipeline has spare capacity or has coordinated with the storage developer to expand capacity on the pipe, the customer bears the cost of transportation to and from storage, in addition to whatever charges the storage developer charges for injections, withdrawals and storage.

3.1.3 Services

Order No. 636

On April 8, 1992, FERC issued Order No. 636 (Final Rule) which directed pipeline companies to complete their transition by eliminating any remaining gas sales activities and to provide fully unbundled services for the gathering and storage of gas as well as transportation.

FERC also directed the pipeline companies to provide a mechanism for the resale of pipeline capacity that is held by firm customers or shippers on a pipeline's system. This mechanism, known as Capacity Release allows shippers to buy, sell or trade firm capacity on a host pipeline without the pipeline's involvement in the transaction.

Transportation Capacity Release Program

Order 636 established a capacity release program under which any shipper with a firm transportation contract authorized under a blanket authorization can remarket transportation capacity, usually to the highest bidder. The bidders can be end users, producers selling and delivering gas directly to customers or marketers buying gas at one location and selling it at another.

The counterparties are free to set the terms and conditions, as long as they are not unduly discriminatory or preferential and the cost does not exceed the applicable maximum rate (which is the maximum firm transportation rate). Offers from a releasing shipper to sell capacity are posted on the pipeline's Electronic Bulletin Board (“EBB”), and interested parties submit bids for the capacity on the same EBB.

Short-term releases of firm transportation capacity (less than thirty days) do not have to be posted on the pipelines' EBBs for competitive bidding. They are posted subsequently for informational purposes. These short-term deals cannot be rolled over into consecutive months unless the replacement shipper agrees to pay the releasing party the maximum pipeline rate.

Except for deals in which the replacement shipper is paying the maximum rate, offers for long-term deals must be posted on the EBB for competitive bids. These bids are open because the terms (but not the bidder's identity) are posted on the EBB as they are received. FERC believes that this allows the market to see and react to the terms and prices being offered.

The winning bid criteria can be posted. However, each pipeline has default criteria that are set out in the pipeline's tariff. Regardless of whether the criteria are specified by the releasing shipper or the pipeline, the pipeline determines the winner.

Once a bid is made, the bidder cannot withdraw it or submit a lower one. The bidder can later submit a higher bid as long as it does not exceed the pipeline's maximum rates (inclusive of all charges).

Releasing shippers can contact a prospective shipper prior to posting on the EBB. If a deal is struck at maximum rates, the deal does not have to be posted. If the deal is for less than maximum rates, it must be posted on the EBB for competitive bids. However, the prospective bidder has the right to match the best bid received.

The successful bidder executes a transportation agreement with the pipeline and is billed directly by the pipeline. The pipeline credits revenue received from the bidder to the releasing shipper’s account, which pays any remaining reservation charges specified in the transportation agreement. However, the releasing shipper can keep excess fees generated by the transaction.

Standards of Conduct

Order No. 497, which issued on June 14, 1988, prescribed the standards of conduct and reporting requirements for interstate pipelines with marketing affiliates. In brief, a pipeline company is prohibited from preferring its marketing affiliate over unaffiliated shippers with respect to transportation matters, access to information, and transportation discounts. In addition, pipelines are required to establish and file with the Commission procedures to enable shippers and the Commission to determine how the pipeline is complying with the standards of conduct.

The Commission stated that the standards of conduct and reporting requirements, established under Order No. 497, would continue to apply to interstate pipelines with marketing affiliates even though the pipelines would be making sales in future on an unbundled basis with transportation separately provided.

The pipeline as a merchant would be the functional equivalent of a marketing affiliate. Pipelines offering unbundled blanket sales services are required to organize their sales and transportation operating employees as an operational unit which is the functional equivalent of a marketing affiliate. In addition, those pipelines are required to conduct their business in conformity with the equality requirements of the Commission by not giving shippers of gas sold by the pipeline any preference over shippers of gas sold by any other merchant. Pipelines must maintain sufficient accounting records to ensure that the cost of providing each unbundled service can be identified and assigned to such service. For any costs in which direct assignment is not possible or practicable, for example general overhead costs, the pipeline may use any reasonable method for allocating such costs among the various services.

The Commission also concluded that the reporting requirements set out in Order No. 497 should apply to pipelines when they provide unbundled gas sales services.

The Commission also requires the pipelines to inform all interested parties on a timely basis about the availability of capacity at receipt points, on the mainline, at delivery points, and in storage fields, and whether the capacity is available from the pipeline directly or through capacity releasing.

All pipelines are required by the FERC to use electronic bulletin boards and that they must not provide preferential access to any users of the electronic bulletin board. They must permit users to download files from the board, so that the contents can be reviewed in detail without tying up access to the board. Pipelines must also keep daily back-up records of the information displayed on their bulletin boards for at least three years and permit users to review those records, which should be archived and reasonably accessible. Pipelines must also periodically purge transactions from current files when transactions have been completed, so that users do not have to sift through massive amounts of historical data to find current information. Information on the most recent entries should appear ahead of older information. In addition, electronic bulletin boards must be "user-friendly." The Commission urged pipelines to use software that allows extremely large files to be split into small parts for ease of use.

Furthermore, the Commission urged pipelines to utilize software with on-line help, a search function that permits users to locate all information concerning a specific transaction, and menus that permit users to access separately each record in the transportation log, notices of available capacity, and standards of conduct information.

The Commission reiterated that, to ensure equality of service, pipelines must include all operating terms, conditions, and rules in their tariffs with the maximum amount of specificity possible.

Capacity Reallocation

The Commission concluded that it is in the public interest for pipeline shippers to have the ability to reallocate unwanted pipeline capacity on a variety of bases to others seeking firm capacity. The only question was how best to accomplish this on an industry-wide basis. The Commission concluded that this required the adjustment of previously authorized capacity brokering and other capacity assignment (upstream capacity assignment and releasing) programs for two reasons. First, while the Commission has required that capacity be brokered or allocated on a non-discriminatory basis, it no longer believed that it could adequately monitor capacity brokering under existing certificates to ensure that all allocations are non-discriminatory. The commission stated that the existence of too many potential assignors of capacity and too many different programs affected the ability of the Commission to properly oversee capacity brokering as it existed at the time. Second, the Commission believed that the two new generic capacity allocation programs it was adopting would make the necessary adjustments to: (1) eliminate the potential for firm capacity holders to unduly discriminate in their assignment of capacity, and (2) facilitate the development of the secondary transportation market.

The Commission, therefore, indicated that it would not be approving new individually authorized capacity brokering and other capacity assignment programs, but rather was amending, by a separate order, the terms and conditions of existing capacity brokering and other capacity assignment certificates to conform to the capacity allocation regulations adopted by this rule. That was to ensure that, after the effective date of this rule, all capacity reallocations are undertaken on the same basis on all pipelines.

4 CALIFORNIA

4.1 OVERVIEW OF THE ENERGY MARKET

The California electricity market serves 10.476 million customers with 33,347 miles of transmission lines and 239,112 miles of distribution lines, and more than 200 electric generation units, for a total economic value of $17.054 billion.[4]

In 1994, the California Public Utilities Commission ("CPUC" or "Commission") issued its Blue Book proposal to open the retail market to competition. This proposal was subsequently implemented into law with the passage of *The Electric Utility Industry Restructuring Act* (Assembly Bill 1890) in 1996 and on April 1, 1998 California's retail market was opened to competition. For its first two years of operation, California's market worked reasonably well. Wholesale prices appeared to be competitive, and approximately 14% of load was served by competitive energy service providers ("ESPs"). However, starting in late 2000/early 2001 wholesale prices began to rise exponentially, Direct Access' share of the market dropped from 15% to 2%, and two of California's utilities were on the brink of insolvency. In 2001, the State of California was forced to begin purchasing energy to meet the needs of California's customers, through the Department of Water Resources ("DWR").

With the passage of AB1X (Statutes of 2000), Direct Access was suspended until DWR was no longer procuring energy. In D.01-09-060, the Commission implemented this suspension. Subsequent to this decision, the Commission has addressed Direct Access rules through several decisions. These decisions have:

- Made Direct Access customers responsible for their share of DWR and utility procurement costs and DWR bond repayment charges incurred during the energy crisis, through implementation of a Cost Responsibility Surcharge ("CRS");
- Capped the CRS for Direct Access customers at 2.7 cents/kWh;
- Allowed customers to renew pre-existing contracts and to switch between ESPs; and
- Defined the terms under which customers could assign their pre-existing Direct Access contract rights between locations and accounts.

Although Direct Access had fallen to as low as 2% of total load, Direct Access participation rates rose back to 14%, close to their pre-energy crisis levels, as the energy market stabilized Direct Access. Under current law, the Direct Access suspension ends with the expiration of DWR contracts in 2013.

Since 2004, the CPUC has been examining the feasibility of creating a "Core/Noncore Market Structure" ("CNC") for that portion of California's electric industry regulated by the Commission. This includes California's three largest investor-owned utilities ("IOUs"): Pacific Gas and Electric ("PG&E"), San Diego Gas & Electric ("SDG&E") and Southern California Edison ("SCE" or

[4] CPUC Annual Report Fiscal Year July 1, 2003 – June 30, 2004

“Edison”), as well as several smaller IOUs. Collectively, these utilities serve about 75% of California’s electric demand, with the remainder served by municipal utilities, irrigation districts and cooperatives[5]. A study conducted by the Commission’s Staff has recommended a Core/Noncore market design with specific conditions that must be met as implementation progresses. The Staff report concluded that once its recommendations are met, a limited Core/Noncore market could start in 2009. This is approximately four years ahead of the current date that the presently legislatively mandated Direct Access suspension would end.

With respect to the natural gas market, most of California's natural gas customers are residential and small commercial customers referred to as "core" customers, who accounted for approximately 40 percent of the natural gas delivered by California utilities in 2003. Large consumers, like electric generators and industrial customers - referred to as "noncore" customers accounted for approximately 60 percent of the natural gas delivered by California utilities in 2003. Approximately 10.5 million customers receive natural gas from PG&E, Southern California Gas (“SoCalGas”), SDG&E, Southwest Gas Company (“Southwest Gas”), and several smaller natural gas utilities.

4.2 OVERVIEW OF THE GAS MARKET

Most of the natural gas used in California comes from out-of-state natural gas basins. In 2003, California customers received 42 percent of their natural gas supply from basins located in the Southwest, 26 percent from Canada, 14 percent from the Rocky Mountains, and 18 percent from basins located within California. The five major interstate pipelines that deliver out-of-state natural gas to California consumers are the Gas Transmission Northwest Pipeline, Kern River Pipeline, Transwestern Pipeline, El Paso Pipeline, and Mojave Pipeline. While the Federal Energy Regulatory Commission regulates the transportation of natural gas on the interstate pipelines, the CPUC often participates in FERC regulatory proceedings to represent the interests of California natural gas consumers.

The price of natural gas sold by suppliers and marketers was deregulated by the FERC in the mid-1980s and is determined by "market forces"; however, the CPUC decides whether California's utilities have taken reasonable steps in order to minimize the cost of natural gas purchased on behalf of their core customers.

4.3 STATE OF GAS GENERATION

Table 2 and Figure 2 indicate that natural gas was the leading primary source of electricity generation for the period 1993-2002. In 2002, for example, gas-fired generation accounted for 25,317MW (44.7%) of the total electric industry’s generating capability followed by hydroelectric power which accounted for 24.9%.

[5] “A Core/Non Core Structure for Electricity in California,” Staff Report, Division of Strategic Planning, California Public Utilities Commission, March 15th, 2004

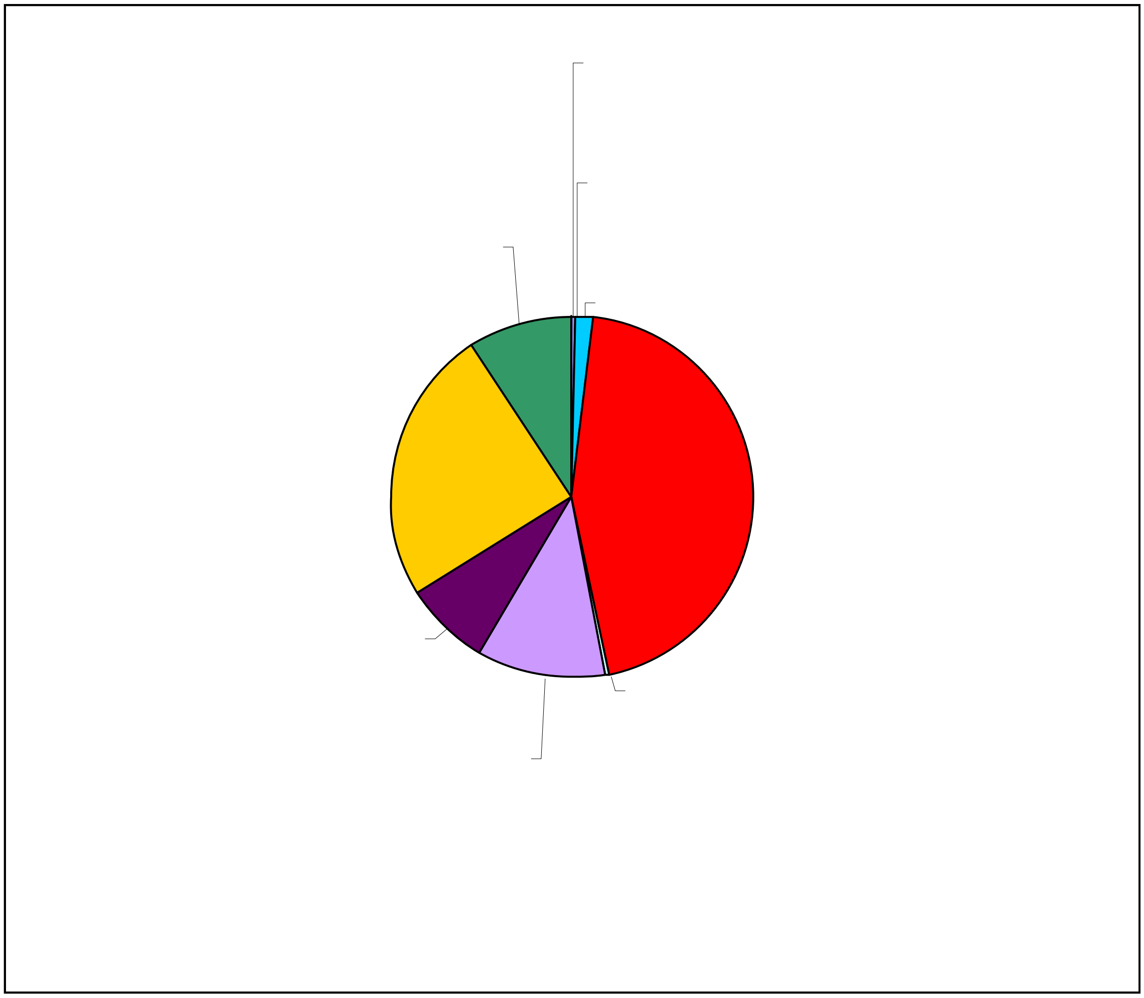
4.3.1 Table 2: Electric Power Industry Generating Capability by Primary Energy Source, 1993, 1997, and 2002 (Megawatts)

Energy Source	**1993**	**1997**	**2002**	**Annual Growth Rate 1993-2002 (%)**	**Share % 1993**	**Share % 1997**	**Share % 2002**
Coal	439	420	352	−2.4	0.8	0.8	0.6
Petroleum.	607	636	705	1.7	1.1	1.2	1.2
Natural Gas	21,668	23,198	25,317	1.7	39.8	43.1	44.7
Other Gases	213	171	226	0.7	0.4	0.3	0.4
Dual Fired	7,215	5,576	6,527	−1.1	13.3	10.4	11.5
Nuclear	4,310	4,310	4,324	0.0	7.9	8.0	7.6
Hydroelectric	14,041	14,125	14,094	0.0	25.8	26.2	24.9
Other Renewables	5,908	5,416	5,102	−1.6	10.9	10.1	9.0
Other	9	9	17	7.8	0.0	0.0	0.0
Total Electric Industry	**35,597**	**35,576**	**36,041**	**0.1**	**100.0**	**100.0**	**100.0**

Source: Energy Information Administration

It can be clearly seen that natural gas is the primary swing fuel, i.e., the amount of natural gas that is used in any given year depends on the availability of hydropower. Electricity generation from hydropower resources, including imports, has ranged from a high of 45 percent during the very wet year (1983) to an all time low of 12 percent during the drought in 2001.

4.3.2 Figure 2. Electric Power Industry Generating Capability by Primary Energy Source (2002)



Much attention has recently been focused on the age and reliability of the state's gas-fired power plants. These combustion turbines, combined cycles, cogeneration units and steam boilers provide a wide range of services. These generation services include baseload energy, following load through its daily swings, and serving as the source of peak capacity that occur only a few times per year. Overall the system has become more efficient as new units are added. Of the 54,675 MW of capacity available to California utilities, 9,369 MW have been added since 2000 and 2,356 MW of older units have been retired. A number of the older plants still in service are expected to retire during the remainder of the decade, largely for economic reasons. Careful maintenance and upgrades over their lifetimes have extended their service lives, but it is expected that they will likely become increasingly unable to compete with newer plants in the marketplace; 13 percent of the state's gas-fired capacity (3,873 MW) and 9 percent of its gas- fired energy in 2002 came from plants built before 1960.

This heavy reliance on natural gas for electricity generation in the face of the recent developments in the natural gas market has prompted the California Energy Commission to come up with a plan which recommends that California must reduce or moderate demand for natural gas and promote fuel diversification, infrastructure enhancements including additional interstate pipeline capacity, increased use of in-state storage, and access to Liquefied Natural Gas ("LNG") facilities on the West Coast.

4.4 SERVICES

Most of the natural gas transported via the interstate pipelines, as well as some of the California-produced natural gas, is delivered into the PG&E and SoCalGas intrastate natural gas transmission pipeline systems (commonly referred to as California's "backbone" natural gas pipeline system). Natural gas on the utilities' backbone pipeline systems is then delivered into the local transmission and distribution pipeline systems, or to natural gas storage fields. Some large noncore customers, that include gas-fired generators, take natural gas directly off the high-pressure backbone pipeline systems, while core customers and other noncore customers take natural gas off the utilities' distribution pipeline systems.

Some of the natural gas delivered to California customers may be delivered directly to them "bypassing" the utilities' systems.

El Paso Natural Gas

El Paso Natural Gas ("EPNG") and its subsidiary Mojave Pipeline Company operate a network of pipelines, delivering natural gas to California, the Southwestern United States, and northern Mexico from supply areas in the San Juan, Permian, and Anadarko Basins. EPNG offers two types of firm transportation service (FT-1 and FT-2) and interruptible transportation service (IT-1) and also interruptible parking and lending service ("PAL"). Parking and lending service rendered under this rate schedule is provided for a minimum term of one (1) day and the service is offered on a non-discriminatory basis.

El Paso's subsidiary, Mojave Pipeline Company has a range of services, in addition to the above standard services provided by El Paso, including interruptible authorized loan service ("ALS-1") and parking service ("APS-1"). The parking service allows parking of gas for a period of up to one calendar month, and such period may be extended with Mojave's permission.

SoCalGas

SoCalGas has electric generation rates for natural gas generators using over 250,000 therms per year (the equivalent of a 220 kW generator running 24/7 all year-round). Natural gas must be separately metered under the electric generation rate GT-F5. The GT-F5 rate costs approximately 4 to 7 cents/therm depending on volume, surcharges, and local taxes. This cost covers transportation only, and does not include the cost of the gas itself, which must be purchased from a natural gas marketer. The GT-F5 rate requires the installation of electronic metering which can cost between $5,000 to $10,000. The rate is an interruptible gas rate and requires a contract with SoCalGas.

For natural gas generators using less than 250,000 therms per year, the generator may be served on the GT-F5 rate as described above, or a standard commercial/industrial

GN-10 gas rate. The GN-10 gas rate is a 3-tier gas rate that includes both transportation and the cost of natural gas itself. Separate metering may or may not be required depending on circumstances. The GN-10 gas rate is a firm gas rate and does not require a contract. In most cases, the cost of the GN-10 gas rate is usually more expensive than the GT-F5 gas rate.

PG & E

PG & E has a gas transportation service tariff under Schedule G-EG for electric generators. This rate schedule applies to the transportation of natural gas used in: (a) electric generation plants served directly from PG&E gas facilities that have a maximum operation pressure greater than sixty pounds per square inch (60 psi); (b) all Cogeneration facilities that meet the efficiency requirements specified in the California Public Utilities Code Section 218.5; and (c) solar electric generation plants. The rates under this schedule may be negotiated.

PG&E also accepts and processes four types of nominations for a given gas day: Timely, Evening, Intraday 1, and Intraday 2:

- A “Timely Nomination”: a nomination received by PG&E no later than 9:30 a.m. one day prior to the gas day for which the Customer requests service;
- An “Evening Nomination”: a nomination received after 9:30 a.m. and no later than 4:00 p.m. one day prior to the gas day for which the Customer requests service
- An “Intraday 1 Nomination”: a nomination received after 4:00 p.m. one day prior to the gas day for which the Customer requests service and no later than 8:00 a.m. on the gas day for which service is requested; and
- An “Intraday 2 Nomination”: a nomination received after 8:00 a.m. and no later than 3:00 p.m. on the gas day for which service is requested by the Customer.

4.5 STORAGE

PG&E and SoCalGas own and operate several natural gas storage fields that are located in northern and southern California. These storage fields, and two independently owned storage utilities, Lodi Gas Storage and Wild Goose Storage, help meet peak seasonal natural gas demand.

In 1993, the CPUC removed the utilities' storage service responsibility for noncore customers, along with the cost of this storage service from noncore customers' rates. The CPUC also adopted specific storage reservation levels for the utilities' core customers.

With respect to storage, SoCalGas owns all the storage facilities in southern California. San Diego Gas & Electric (Sempra) purchases its storage services from SoCalGas. Pacific Gas & Electric owns the remaining storage facilities in northern California.

SoCalGas offers three storage programs:

Basic Storage (“BSS”) is ideal for curtailment protection. BSS is a one-year storage option for retail noncore customers, and offers firm inventory, injection, and withdrawal service. The program has two open season periods. The Spring Open Season is held in February and is effective starting April 1. The Fall Open Season is held in August and is effective starting October 1.

Long Term Storage ("LTS") is ideal for customers who need to meet service obligations created by peak winter and/or summer demands. This service provides curtailment protection. LTS, is available for periods of three to fifteen years, offers the ability to customize a package that best meets customer's specific requirements for combining inventory, injection and withdrawal services.

Transaction Based Storage ("TBS") is ideal for customers seeking maximum flexibility in a storage program. TBS allows the packaging of different storage services to meet the customers' diverse and dynamic energy needs. It is available for periods of one month to three years, and can also be used for price arbitrage purposes. Under this storage service rate schedule, the Utility provides unbundled storage services for a minimum term of one month and not more than three years. The storage service package and associated charges are negotiated on a transactional basis between the customer and the Utility depending on market conditions and customer needs. This is an experimental rate schedule under which the Utility may offer service until such time as a new storage program is implemented by the Commission.

4.6 JURISDICTIONAL POLICY

Although most of California's core customers purchase natural gas directly from the regulated utilities, core customers have the option to purchase natural gas from independent natural gas marketers. Most of California's noncore customers, on the other hand, make natural gas supply arrangements directly with producers or purchase natural gas from marketers. As such, noncore customers are not responsible for paying for the interstate pipeline capacity that the utilities had obtained for all their customers.

In a 1997 decision, the CPUC adopted PG&E's "Gas Accord," which unbundled backbone transmission costs from noncore transportation rates, and gave customers and marketers the opportunity to obtain pipeline capacity rights on PG&E's backbone pipeline system. The Gas Accord also required PG&E to set aside a certain amount of pipeline capacity in order to deliver natural gas to its core customers. In Decision D.03-12-061, issued in December 2003, the CPUC modified and extended the initial terms of the Gas Accord. In December 2001, the CPUC adopted the "Gas Industry Restructuring" decision in D.01-12-018. This decision adopted a market and regulatory structure for SoCalGas similar to the Gas Accord structure for PG&E. In D.04-04-015, the CPUC adopted the tariffs to implement restructuring of the SoCalGas system, but stayed that decision to consider issues in a major Rulemaking, R.04-01-025.

4.6.1 COST RECOVERY OF INVESTMENT ON INTRASTATE TRANSMISSION/STORAGE

The CPUC is responsible for approval of applications to construct **intrastate** transmission facilities. In general, the cost of investment in new gas infrastructure can be rolled-in or incremental. Individual circumstances determine the approved allocation method.

The latest and readily available decision by the CPUC relating to cost recovery of investment in new gas infrastructure was released on September 2, 2004. The Commission's decision was part of an Order Instituting Rulemaking ("OIR") to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California under Rulemaking 04-01-025. The OIR was opened to ensure that California does not face a natural gas shortage in the future. The decision addressed the Phase I proposals of SoCalGas, SDG&E, PG&E and Southwest Gas. The proposals were filed in accordance with this OIR and addressed interstate pipeline capacity contracts, LNG access, and interstate pipeline access. In particular, SoCalGas and SDG&E proposed to roll-in (have ratepayers pay for) costs up to $100,000 per MMcf/d for each project and a total cost of no more than $200 million in LNG-related infrastructure improvements, as long as the utilities can show that there is a cost benefit in doing so. They argued that at these levels, it could safely be assumed that the benefits exceed associated costs. At higher cost levels, additional evidentiary proceedings could be required to demonstrate that benefits exceed cost, but below these levels, additional evidentiary hearings and associated regulatory delay would only act to the detriment of southern California natural gas consumers.

The utilities indicated that the $200 million cap translated into a transportation rate increase of less than four cents per Mcf, and the bill impact for the typical residential customer, before considering the commodity benefit, would be an additional 25 cents per month.

Specifically, SDG&E and SoCalGas recommended that the following policy statement be adopted in Phase I of that proceeding:

> It is in the interest of California that new sources of gas supply be encouraged. Therefore, to the extent that the benefits to all utility customers of access to the new gas supplies are greater than the cost to utility customers, the costs of expanding utility backbone facilities necessary to accommodate new gas supplies should be rolled-in to the utilities' system wide transportation rate. Below a certain cost threshold, it should be presumed that benefits exceed cost.

The utilities pointed out that this policy statement was consistent with the California Energy Action Plan's direction on new supply sources and also with FERC policy on rolled-in ratemaking.

The CPUC noted that the issue of rolled-in versus incremental ratemaking treatment for particular utility facilities was complicated by the enormous uncertainty regarding LNG projects, specifically, which facilities will ultimately be developed and when. In addition, potential construction costs to accept and redeliver significant volumes of gas at multiple new receipt points varies widely, depending on which new sources of supply actually materialize and the volumes to be delivered at each new receipt point.

Based on such concerns, the CPUC felt that it was appropriate to await further developments regarding the permitting and construction of LNG terminals before deciding the extent, if any, to which backbone facility costs should be rolled-in to system-wide transportation rates. As a result, the Commission adopted a policy that presumes LNG suppliers would pay the actual system infrastructure costs associated with their projects. However, requests for rolled-in, or any alternative ratemaking treatment, could be filed through the application process, with appropriate notice to customers. Those proposals, including the costs and cost recovery mechanisms, could then be evaluated on a case-by-case basis.

4.6.2 STORAGE

The CPUC unbundled noncore storage in 1993, i.e., utilities were no longer responsible for ensuring that noncore customers had their storage requirements met. Storage costs were removed from noncore rates. Noncore customers contract and pay for storage service on an unbundled basis. On the other hand, the utility distribution companies provide storage as a bundled product to residential and commercial customers. The CPUC also specified storage reserve levels for the utilities' core customers.

All storage built by the utilities is available to core and noncore customers at regulated rates. With respect to the construction and expansion of storage facilities, the Commission had earlier adopted a regulated approach; later on, however, it implemented what came to be known as a "let the market decide" policy because it felt that the earlier approach failed to stimulate infrastructural investment in pipelines and storage. That policy seemed to have an impact of encouraging companies to make investments on more storage because subsequently two independent storage facilities were opened. The first was the Wild Goose Storage which was opened in 1999 and the second one was the Lodi Gas Storage which came online in 2001. These independent storage facilities provide their services at market-based rates; nevertheless, they are responsible for any risk affecting their commercial performance, to the extent any capacity is unsubscribed.

4.6.3 COST RECOVERY OF INVESTMENT ON INTERSTATE TRANSMISSION/STORAGE

For interstate pipelines regulated by FERC and operating in the State, FERC's rules on approval of new transmission facilities and cost allocation apply. In general, when a certificate application is filed, the threshold question applicable to existing pipelines is whether the project can proceed without subsidies from their existing customers. This will usually mean that the project would be incrementally priced, but there are cases where rolled-in pricing is allowed; for example, when the projects are designed to improve existing service for existing customers, by replacing existing capacity, improving reliability or providing flexibility.

4.7 RECENT DEVELOPMENTS

Since 2000, California has investigated the effect of increased dependence on natural gas for electric generation.

A RAND study conducted in 2002 reported that the pipeline infrastructure in California and other western states at the time was operating close to capacity and that plans for interstate pipeline expansion may lag behind projected demand growth. The study also pointed out that the growing summer peak in gas consumption for electric generation has placed stress on the management of storage since injections to storage will need to occur over a shorter period of time. Strong demand growth for electric generation was also perceived as a strain to the gas transmission and distribution infrastructure, which could jeopardize gas service to all customers. The study recommended that California begin to address potential infrastructure shortfalls by looking at increasing receipt capacity, building new pipelines, increasing the capacity of existing pipelines and studying the viability of increasing storage capacity. The report also indicated that the inadequacy of intrastate capacity is particularly serious as it makes it more difficult for the gas transmission system to deal with disturbances and sudden surges in load.

The California Energy Commission has studied the problem of possible shortfalls in intrastate pipeline capacity. Specifically, it identified the major problem as planning for summer peak demands in view of the growing demand by gas-fired generators. In a 2001 report, the Commission recommended new design criteria and reliability standards for the state's natural gas system largely because of the significant growth in gas consumption by electric generators. The report argued that the then current design criteria were no longer relevant because of the erosion of fuel switching capability by gas-fired facilities. It advocated an integrated planning function for the state's gas pipeline and storage facilities to identify needed additions in response to future demand.

The report concluded that the high gas prices in California in 2000 and early 2001 were partially the result of inadequate capacity to receive gas at the California border.

Finally, the report identified the challenge facing decision-makers in choosing between serving electric generators during the summer months and storing sufficient gas for winter use.

In December 2003, the California Energy Commission issued its Integrated Energy Policy Report ("IEPR") in which it recommended that California must reduce or moderate demand for natural gas and promote infrastructure enhancements, such as additional interstate pipeline capacity, increased use of in-state storage, and access to LNG facilities on the West Coast.

5 ILLINOIS

5.1 OVERVIEW OF THE ENERGY MARKET

The energy market in Illinois (“State”) is extensively interconnected with that of the surrounding states. With respect to the electricity market in particular, whereas most of the transmission and distribution facility owners are members of the Midwest Independent System Operator (“MISO”), Commonwealth Edison, the electric transmission and distribution utility serving 70% of the state’s population, is a member of the PJM Interconnection. The electric LDCs are unbundled and have divested their generation facilities. Both the gas and electricity markets are competitive down to the residential customer level although the distribution LDCs continue to provide retail service. In addition to natural gas-fired facilities, there are significant coal-fired and nuclear generation resources. There are also coal mining operations within the State and in some of the adjacent states. Illinois has its own coal mining industry. According to U.S. Energy Information Administration (“EIA”) data, Illinois produced 31.8 million short tons of coal in 2003, of which 7.1 million tons, or 22.3%, was used by generators within the state. This local production represented 14% of the total coal used for electricity generation in Illinois in 2003.

5.2 OVERVIEW OF THE GAS MARKET

There are several interstate pipelines providing natural gas service within the state including ANR Pipeline Company (“ANR”), Panhandle Eastern Pipeline Company (“Panhandle Eastern”), Trunkline Gas Company, Midwestern Gas Transmission, Natural Gas Pipeline of America (“NGPLA”), Northern Border Pipeline and the Alliance Pipeline. These pipelines provide customers in the State with access to supplies from most of the major North American supply basins. In addition, there is significant storage capability both within the Sate and in adjacent states.

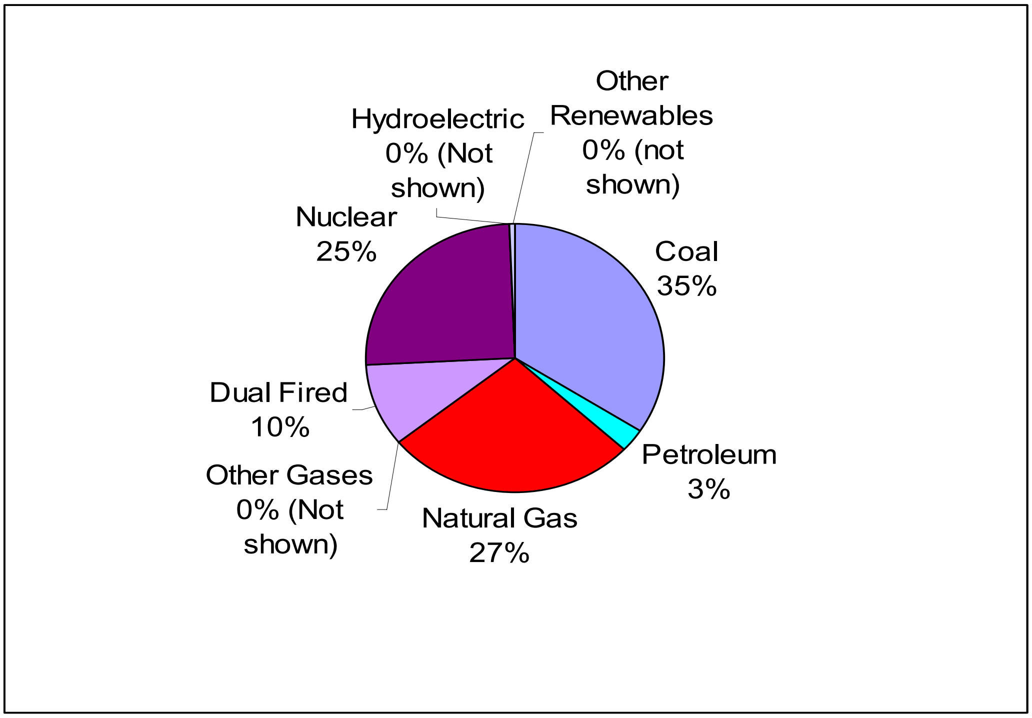
5.3 STATE OF GAS GENERATION

According to state profile data available from the U.S. EIA as set out in the tables below, natural gas fired generating capacity in Illinois grew by over 310% between 1997 and 2002, an average rate of over 62% per year. However, in the 2002 to 2003 period the rate of growth slowed to 3.4%. Similarly, while natural gas’s share of the power generated in the state grew from 3.2% in 1997 to 4.8% in 2002, this dropped to 2.1% in 2003. This reflects the fact that many of the natural gas-fired generating facilities in the state are dispatchable.

5.3.1 Table 3. Illinois Electric Power Generating Capability by Energy Source 1993, 1997, 2002 and 2003 – Total Electric Industry

Energy Source	1993 MW	1997 MW	2002 MW	2003 MW	Share 1993 %	Share 1997 %	Share 2002 %	Share 2003 %
Coal	15,391	15,732	15,654	15,561	46.1	45.6	35.0	34.3
Petroleum	2,638	2,320	1,295	1,246	7.9	6.7	2.9	2.7
Natural Gas	2,151	2,877	11,881	12,289	6.4	8.3	26.6	27.1
Other Gases	55	45	40	40	0.2	0.1	0.1	0.1
Dual Fired	509	727	4,356	4,594	1.5	2.1	9.7	10.1
Nuclear	12,609	12,609	11,312	11,465	37.7	36.6	25.3	25.2
Hydroelectric	30	34	21	33	0.1	0.1	0.0	0.1
Other Renewables	32	135	154	213	0.1	0.4	0.3	0.5
Total	**33,415**	**34,478**	**44,712**	**45,411**	**100.0**	**100.0**	**100.0**	**100.0**

5.3.2 FIGURE 3. ILLINOIS ELECTRIC POWER GENERATING CAPABILITY BY ENERGY SOURCE (2003)



5.3.3 TABLE 4. ELECTRICITY GENERATION IN ILLINOIS BY PRIMARY ENERGY SOURCE 1993, 1997, 2002 AND 2003

Energy Source	1993 GWh	1997 GWh	2002 GWh	2003 GWh	Share 1993 %	Share 1997 %	Share 2002 %	Share 2003 %
Coal	61,490	78,121	86,685	87,981	42.9	57.8	46.1	46.5
Petroleum	734	528	223	1,121	0.5	0.4	0.1	0.6
Natural Gas	2,127	4,283	9,079	3,902	1.5	3.2	4.8	2.1
Other Gases	347	361	233	204	0.2	0.3	0.1	0.1
Nuclear	78,373	51,069	90,860	94,733	54.6	37.8	48.3	50.1
Hydroelectric	130	97	129	139	0.1	0.1	0.1	0.1
Other Renewables	251	682	845	974	0.2	0.5	0.4	0.5
Other	0	0	1	1	0.0	0.0	0.0	0.0
Total	**143,452**	**135,141**	**188,055**	**189,055**	**100.0**	**100.0**	**100.0**	**100.0**

The data from the U.S. Department of Energy's ("DOE") EIA indicates that natural gas fired generating capability increased dramatically during the 1997 to 2002 period but that this rate of increase slowed significantly in 2003. Similarly, while natural gas's share of the electricity generated on an annual basis more than doubled from 1983 to 1997 and increased again by 112% from 1993 to 1997, it decreased by 57% between 2002 and 2003. During all of these time periods, the predominant sources were nuclear and coal fired generation. This again reflects the dispatchable nature of many of the gas-fired plants.

5.4 SERVICES

Large volume customers may be served either directly off of the interstate pipelines or off of the distribution systems of the LDCs. Many of these pipelines have tariffs which are supportive of gas fired generation. For instance the tariff for Kinder Morgan's NGPLA offers a Firm Transportation Service which allows for late nominations and a Nominated Firm Storage Service which has a number of flexible characteristics including no-notice capabilities when combined with one of its transportation services.

ANR

ANR's tariff allows for multiple intra-day nominations and it has a firm transportation service, FTS-3, which it has tailored to the electricity generation market. Among the features of this rate is the ability to have a maximum hourly quantity that is equal to 25% of the maximum daily quantity.

Panhandle Eastern

Panhandle Eastern also has rates with flexible delivery characteristics including its Hourly Firm Transportation Service which is designed to accommodate shippers with the need for accelerated flow rates on relatively short notice over a limited number of hours within the gas day. Under this rate schedule a shipper can elect to receive its entire maximum daily quantity over a specified hourly period within the gas day. The service is nominated and scheduled on a daily basis with the pipeline's Gas Control Department having to be notified three hours before the time of start-up for delivery of gas. Although somewhat less flexible, Panhandle Eastern's Enhanced Firm Transportation Service allows shippers to take up to one-sixteenth of the uniform hourly quantities scheduled for delivery without incurring a scheduling penalty.

Trunkline Gas Company, an affiliate of Panhandle Eastern, also offers a transportation service which is designed to meet the needs of the generation market. Its Quick Notice Transportation Service allows transportation customers to adjust their nominations once each hour on a prospective basis to be effective on any hour of the gas day as long as the nomination change is submitted before 4:00 p.m.

Midwestern Gas

Midwestern Gas Transmission's Firm Transportation Service does not offer the same flexibility as those described above because of the requirement that deliveries during the day be on a uniform basis; however, its tariff provides that the pipeline will try and accommodate customers who wish to deliver or receive non-uniform quantities during the day. All of its rates are negotiable within the ranges set out in its FERC-approved tariff.

Peoples Energy

The Peoples Gas Light and Coke Company and the North Shore Gas Company are subsidiaries of Peoples Energy. Together they serve more than one million customers in Chicago and other northern Illinois communities. Their tariffs are very similar in nature. Each of these companies offers a Contract Service for Electric Generation. In each instance the characteristics of the service, the charges for the service and the terms and conditions are negotiated between the customer and the utility and then set out in a contract which is filed, on a confidential basis, with the Illinois Commerce Commission ("ICC") for informational purposes. Each of the utilities also offers a Standby Service that provides a lower rate for gas used for non-heating services as opposed to that used for heating.

Central Illinois Light Company

Central Illinois Light Company, a subsidiary of Ameren which serves just over 200,000 customers in central and east central Illinois, has a Rate 800-Contact Service which is designed to deal with potential bypasses of its system. Under this rate the nature of the service, the charges and the terms and conditions are negotiated and set out in a contract that is filed on a confidential basis with the ICC for informational purposes. The maximum term of the contract is five years and it must be accompanied by affidavits stating the customer's intent to bypass the utility and connect to an interstate pipeline if this service is not provided.

Northern Illinois Gas Company

The Northern Illinois Gas Company, or Nicor, is the largest gas distribution utility in the State and serves more than two million customers. Nicor has two rates designed specifically to serve the needs of generating customers. Rate 11 includes the provision of gas supply while Rate 81 is a transportation rate. Rate 81 does include a largely optional storage banking service, under which the customer is subject to a minimum equivalent to one times their maximum daily quantity and an optional Firm Backup Service. These rates are only available to generation customers which were taking service prior to April 11, 1996. It would appear that generation customers taking service after that date must use Nicor's Large Volume Transportation Service, Rate 77.

5.5 STORAGE

Customers in Illinois have access to storage from several sources including many of the inter-state pipelines and some of the larger LDCs.

ANR

ANR's storage operation is located primarily in the nearby state of Michigan and has a maximum capacity of 56 billion cubic feet ("Bcf"). The service is provided pursuant to a FERC-approved tariff and the rates are negotiated within a posted range where the minimum rate is $0. The service parameters set out in the customer's service agreement are also negotiated. ANR also provides parking and loan services by way of its Joliet Hub Service.

Panhandle Eastern

Panhandle Eastern provides storage service including a firm Flexible Storage service which allows for customized firm injection and withdrawal rights. Its affiliate, Trunkline Gas Company also offers storage along with parking and loan service.

Northern Illinois Gas Company

Nicor has 165 Bcf of storage within the State which it uses both to meet the needs of its distribution customers and to provide storage and hub services to customers of interstate pipelines. It can meet half of its peak day through the use of these facilities. Nicor uses these facilities, which are connected to seven interstate pipelines, to provide a range of services including firm and interruptible storage and parking and loans. The rates for the storage services provided to distribution customers are regulated by the ICC while the services to the customers of interstate pipelines are subject to negotiable rates that form part of a FERC-approved tariff. The minimum rate approved for these services is $0.00.

Other Utilities

Midwestern Gas offers parking and loans service with rates that are negotiable within a FERC-approved range and unregulated subsidiaries of Peoples Energy also offer hub services.

5.6 JURISDICTIONAL POLICY

The electric LDCs in Illinois, which were at one time fully integrated, have divested themselves of their generating assets. In some instances the assets were sold to unaffiliated companies and in others they were transferred to affiliates. The state LDCs are subject to a price freeze until the end of 2006. They are currently involved in hearings before the ICC involving approval of their procurement practices for 2007. The utilities are proposing that an auction process be established which would provide the utilities' customers with a fixed price

The facilities required to directly connect a new customer are generally recovered from that customer; however, for the utilities regulated by the ICC, the costs for facilities upstream of the connection point are usually rolled-in. Such expansions are generally not required because electric demand peaks in the summer and the distribution systems which are sized to meet the peak natural gas requirements, which occur in the winter months, are capable of accommodating the requirements of the electricity generators. The interstate pipelines are subject to FERC's ruling with respect to the tolling treatment applicable to new facilities.

Although not as large as in some states, the coal mining industry is a significant industry in the State. Legislation has been introduced which will allow utilities to buy pipeline quality coal gas without being subject to a prudence review.

According to the ICC's 2004 annual report, the rules for the transfer of power between a cogeneration facility and a utility, as established by statute, require that the utility must pay a cost that is commensurate with its avoided cost of power. The ICC states that its intent when dealing with contractual arrangements between cogeneration facilities and utilities is to promote economic cogeneration while avoiding uneconomic bypass of the utility's system.

6 MICHIGAN

6.1 OVERVIEW OF THE ENERGY MARKET

Since the late 1990s, Michigan has been carrying out restructuring activities in the electric, natural gas and telecommunications industries. In natural gas, twelve utilities provide gas service to approximately three million customers who consume over 900 billion cubic feet (25.5 billion cubic metres) of natural gas per year. Customer Choice programs were approved for the four largest gas companies, Aquila Networks-MGU, Consumers Energy Company, Michigan Consolidated Gas Company, and SEMCO Energy Gas Company. The Michigan Public Services Commission ("MPSC" or "Commission") also approved a phase-in of customer choice programs for customers of Detroit Edison and Consumers Energy.

In electricity, the MPSC regulates nine privately owned electric utilities (investor-owned) and 10 rural electric cooperatives (coops). Municipally owned electric (munis) or water utilities are not subject to MPSC regulation. The electric industry has been restructured so that the generation and supply of electricity is now open to competitive suppliers. The electric transmission and distribution businesses remain under a regulated monopoly utility structure. Michigan's *Customer Choice and Electricity Reliability Act* (2000 PA 141) took effect in June, 2000. The Act directed MPSC to issue orders that gave all customers of Michigan's investor-owned utilities the ability to choose an alternative electric supplier ("AES"), starting in January 2002. Customers of Michigan's member-owned cooperative electric distribution companies that have a maximum demand of 200 kilowatts or more also became eligible to participate. Other co-op customers will become eligible after January 1, 2006. The rules are different for municipal electric utilities that are not regulated by the MPSC. Generally speaking, it is up to each municipal utility's local governing board to make decisions about electric choice for their customers.

6.2 OVERVIEW OF THE GAS MARKET

Michigan, the twelfth largest natural gas producing state in the U.S., produces about 20% of the total gas consumed in Michigan and imports the rest from other sources including Canada. Natural gas utilities in Michigan currently purchase their gas supplies from various sellers at the source of the interstate pipelines, and pay the pipelines solely to transport their gas. Major interstate pipelines include ANR Pipeline Company (an El Paso Company) , CMS Trunkline Gas Company , Northern Natural Gas Company , Great Lakes Gas Transmission Company , and Vector Pipeline Company which commenced service in 2000. There are two Non-Interstate Pipelines that connect to Canada: Bluewater Pipeline Company and Michigan Consolidated Gas Company.

6.3 STATE OF GAS GENERATION

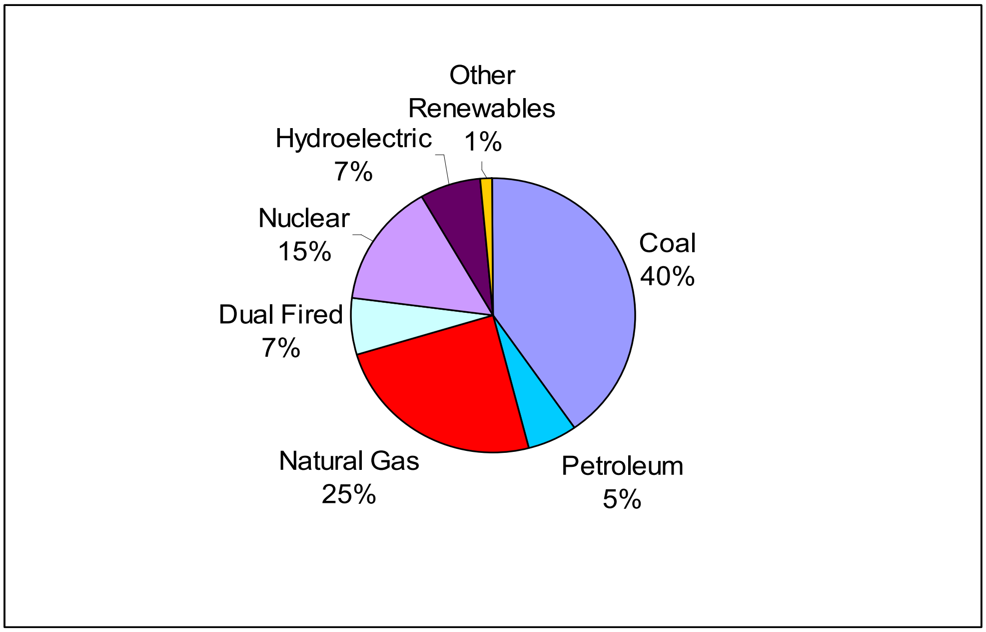
Natural gas-fired generation in Michigan accounted for 9.4%, 12.5%, and 13.4% of electricity produced in the State in 1993, 1997, and 2002 respectively, indicating a growth rate of 5.2% for the period 1993-2002.

6.3.1 TABLE 5. ELECTRIC POWER INDUSTRY GENERATING CAPABILITY BY PRIMARY ENERGY SOURCE, 1993, 1997, AND 2002 (MEGAWATTS)

Energy Source	1993	1997	2002	Annual Growth Rate 1993-2002 (%)	Share % 1993	Share % 1997	Share % 2002
Coal	12,572	12,432	11,981	−.5	49.9	50.0	40.8
Petroleum	1,507	2,369	1,610	.7	6.0	9.5	5.5
Natural Gas	2,054	2,186	7,289	15.1	8.2	8.8	24.8
Other Gases	282	11	0	NM	1.1	. 0	.0
Dual Fired	2,215	1,359	2,000	−1.1	8.8	5.5	6.8
Nuclear	3,967	3,922	3,938	−.1	15.8	15.8	13.4
Hydroelectric	2,226	2,154	2,129	−.5	8.8	8.7	7.3
Other Renewables	346	426	388	1.3	1.4	1.7	1.3
Total	**25,169**	**24,859**	**29,335**	**1.7**	**100.0**	**100.0**	**100.0**

Source: Energy Information Administration/State Electricity Profiles 2002

6.3.2 Figure 4. Electric Power Industry Generating Capability by Primary Energy 2002



6.3.3 Table 6. Electric Power Industry Generation of Electricity by Primary Energy Source, 1993, 1997, and 2002

Energy Source	Megawatt hours			Percentage Share		
	1993	1997	2002	1993	1997	2002
Coal	63,959,081	67,444,850	66,699,509	60.1	63.0	56.6
Petroleum	761	757,653	1,103,485	0.7	0.7	0.9
Natural Gas	10	13,388,311	15,853,418	9.4	12.5	13.4
Other Gases	3	959	10,108	0.0	0.0	0.0
Nuclear	28	21,913,808	31,087,454	26.8	20.5	26.4
Hydroelectric	988	778,080	633,692	0.9	0.7	0.5
Other Renewables	2	2,668,976	2,501,404	1.9	2.5	2.1
Other	37	18,122	18	0.0	0.0	0.0
Total	**106,368,552**	**106,970,760**	**117,889,087**	**100.0**	**100.0**	**100.0**

Source: Energy Information Administration/State Electricity Profiles 2002

Gas-fired Generators could be firm or non-firm customers and obtain transportation services from regulated utilities, and purchase gas supplies from unregulated marketers. Special contracts for transportation and storage are typically negotiated. The price of electricity generated by gas-fired generators is market-based.

6.4 SERVICES

The different pipelines and storage companies offer a variety of services, not specifically designed for gas-fired generators but which the latter may find attractive, including *peaking*, *no notice*, *balancing* and *over run* services and *intra-day* nominations and others. Some companies also indicate that they have services that are specifically designed for power generators.

ANR Pipeline Company

ANR's FTS-3 (firm transport) and ITS-3 (Interruptible transport) services are specifically tailored to meet the needs of the power generation market. These services provide shippers with greater flexibility such as daily entitlements delivered at hourly flow levels, shorter notice periods for start-up and shutdown, and greater daily and monthly tolerances. In addition to the general nomination and scheduling procedures described in the General Terms and Conditions, a Shipper may elect the right to start-up and shut-down service upon providing ANR with two (2) Hour(s) telephone notification or, subject to operational conditions, a shorter period of notice. ANR also has a premium no-notice service ("NNS") that allows a shipper to meet unforecasted and, therefore, unnominated changes in demand requirements. NNS acts as an "umbrella" for other services covering storage and related transportation contracts between storage and the shipper's city gate. Customers can designate a sequencing to balance storage inventory with their no-notice activity.

Panhandle Eastern Pipe Line Company, LP

Besides standard FT and IT services, services that are designed to meet the specific needs of power generators include:

- Hourly Firm Transportation -- Customized flow patterns to meet the needs of electric generators;
- Quick Notice Transportation -- Flexible nomination/scheduling procedures for shippers who need to react quickly to flow rate changes;
- Enhanced Firm Transportation -- Provides non-rateable flow in the gas day;
- Gas Parking Service -- Parking and lending to minimize imbalances and penalties;
- Flexible Storage Service -- Allows for customized firm injection and withdrawal rights subject to Panhandle Energy's approval;
- No Notice Service -- Combines transportation and storage services to simplify nominations and imbalance management;
- Flexible Field Zone Firm Transport -- Tailored to enhance gas supply attachment offshore;
- Intraday Gas Parking Service -- Provides intraday swing for shippers using standard IT or FT services;
- Delivery Variance Service -- Provides incremental tolerance for daily scheduling variances.

6.5 STORAGE

Michigan's available underground natural gas storage is significant. With about 623 Bcf of working gas capacity, Michigan has more storage than any other state. This storage provides for more efficient use of transmission pipelines that bring supply to Michigan utilities, and helps stabilize prices. Michigan's gas usage is highly seasonal, and the storage capability allows gas purchases to be made throughout the year. This lowers prices for consumers, since gas can be purchased in summer months when prices are lower, then put in underground storage and used in winter months. Storage is provided by distribution utilities and gas storage companies under rates and services approved by the MPSC. Interstate transmission pipeline and storage companies also provide storage services in Michigan under FERC's regulatory oversight.

6.6 JURISDICTIONAL POLICY

6.6.1 COST RECOVERY OF INVESTMENT ON INTRASTATE TRANSMISSION/STORAGE

The MPSC is responsible for the approval of applications to construct **intrastate** transmission facilities. Applicants are required to file an estimate of the total cost of the project, the anticipated revenue, operating expenses and earnings for a five-year period. Any contracts for service must be included in the filing; however, the Commission has not established any minimum purchase commitment.

The cost of investment in new gas infrastructure could be rolled-in or incremental. Individual circumstances determine the approved allocation method.

Tariffs for intrastate gas transmission/storage can be cost-of-service based or market-based. Initial rates for a new intrastate pipeline are filed with the Commission. No change in rates can be made until such change is approved by the Commission.

6.6.2 COST RECOVERY OF INVESTMENT ON INTERSTATE TRANSMISSION/STORAGE

As noted earlier, FERC's typical allocation of the cost of investment in new gas infrastructure (transportation and storage) is based on incremental pricing. However, there are instances when it allows costs to be rolled-in.

6.6.3 SERVICES FOR GAS-FIRED GENERATORS MANDATED BY MPSC

Special services for gas-fired generators are not mandated by the MPSC, i.e., it doesn't require pipelines and storage operators to provide any special services to gas-fired generators. The MPSC however approves procedures related to gas curtailment with respect to gas-fired generators. Electric utilities are provided with Priority One service to the extent necessary to avoid the implementation of Emergency Electrical Procedures. This is dependent upon actions to minimize the use of gas including: 1) bringing on line any non-gas reserve capacity; 2) switching gas fired dual-fuel generating plants to an alternate fuel; 3) attempting to procure incremental purchased power; and 4) curtailing all non-firm off-system electric sales. If the emergency is severe in nature such that Priority One service must be curtailed, then sufficient gas service must be provided to allow the electric utility to maintain its system integrity as it implements its short-term and long-term Emergency Electrical Procedures. Gas curtailment procedures are amended from time to time. No changes have been made in the last five-years.

6.7 RECENT DEVELOPMENTS

In 1999, the Michigan Public Service Commission published a report entitled "Gas-Fired Generation in Michigan: Assessment of Gas Infrastructure and Generation Costs". Key items addressed in this report were the future supply and prices of gas, the ability of the gas pipeline system to deliver gas to gas-fired generators, the impact of gas-fired generation on Michigan's distribution and storage infrastructure, and the expected cost of electricity from gas generators. In this initial assessment, the Commission Staff found that:

- Michigan's gas pipeline capacity was at the time inadequate for serving significant gas-fired generation in Michigan, but proposed projects would provide the necessary pipeline capacity;
- Gas supplies would be sufficient to provide fuel for gas-fired generation and to serve traditional natural gas markets for the foreseeable future, at reasonable prices;
- Michigan's abundant natural gas storage should provide fuel price benefits for gas-fired generators similar to the price benefits already received by Michigan's gas space heating customers;
- Michigan's gas storage combined with its winter peaking season for gas use suggested that Michigan was a good location for gas-fired electricity generation, given summer peaking electricity demand; and
- Natural gas prices should remain favorable for the foreseeable future. However, Commission Staff believed the likelihood of higher than expected prices was greater than for lower prices.

Under the U.S. Department of Energy's reference wellhead natural gas prices, busbar baseload generation using natural gas was approximately 3.4-3.5 cents per kilowatt-hour in 1999, and would increase to about 4.1-4.2 cents by 2005.

In 2005, in Case No. U-14231 the MPSC initiated a review of the adequacy of Michigan's electric generating capacity and other related infrastructure. MPSC Staff was directed to convene a Capacity Need Forum that includes representatives of the power generation community and other interested parties, to accumulate, assess and evaluate data on the construction of new generation capacity for meeting Michigan's future needs. The Commission also directed these parties to recommend policies that will facilitate the development of new base-load generation facilities in Michigan. Staff filed a status report on July 1, 2005 and a final report is expected on January 1, 2006. The investigation will analyze all power supply cost recovery filings for five year load growth forecasts, system requirements and other data on the need for resource additions. It will include analysis of available energy efficiency and demand response resources, transmission and distribution system upgrades, and options for new generating capacity including traditional utility central-station generators as well as renewable resources. The report will address: the anticipated short, intermediate and long-term demand for power; the ability to meet projected demands from existing resources; and potential resource options that are available, if additional resources are needed.

7 NEW YORK

7.1 OVERVIEW OF THE ENERGY MARKET

In 1999, New York State moved from a traditional regulated structure of its electricity sector to one that permitted and welcomed competition at the wholesale level. The New York Public Service Commission ("PSC") approved utility plans that give electric customers access to new energy suppliers known as energy service companies, or "ESCOs." The plans require the utilities to offer retail choice to customers who want to shop for electricity and related services. The delivery of electricity to homes and businesses, however, would remain the responsibility of the local utility and continue to be regulated.

On March 14, 1996, the PSC approved plans to allow residential, small business, commercial, and industrial customers the option to buy their own natural gas supply from sources other than the traditional utility companies.

Currently, New York has a workable, competitive wholesale market. In addition, New York's retail market for the largest use customer classes has attracted most of the electric and gas load. By the end of 2004, 6.2% of customers[6], accounting for 33% of state-wide load, had "migrated" to competitive markets. Most migrating customers were from non-residential classes – 48.1% of large non-residential customers and 13% of small and medium-size non-residential customers, accounting for, respectively, 66.8% and 36.2% of the load in their classes. Migrating residential consumers account for 5.1% of all residential consumers and 7.2% of residential load.

7.2 OVERVIEW OF THE GAS MARKET

The pipeline companies serving New York State, interstate and intrastate, are: Algonquin Gas Transmission, Columbia Gas Transmission, Dominion Transmission, Empire State Pipeline Co., Iroquois Gas Transmission System, National Fuel Gas Supply Co., North Country Pipeline, Tennessee Gas Pipeline Co., Texas Eastern Pipeline Co., Transcontinental Gas Pipe Line Corp., and TransCanada Pipelines Limited.

New York's gas industry is also served by thirteen gas distribution companies (commonly referred to as LDCs); and local gas production and storage facilities. New York has a diversified supply mix, receiving gas from U.S. production in the Southwest, the Gulf Coast and Appalachia as well as New York; Canadian supplies from both western and eastern basins; and small amounts of imported LNG from various foreign sources (delivered via exchange/displacement from New England). LNG provides nearly 10 percent of New York's peak day requirements, and only about one percent of New York's total annual gas supply.

[6] State Energy Planning Board - 2004 Annual Report and Activities Update (Data does not include customers of Long Island Power Authority, small regulated utilities, and municipalities and other entities supplied power through long-term contracts with the New York Power Authority.)

7.3 STATE OF GAS GENERATION

According to the most recent U.S. EIA data (2001, released Nov. 2004), Natural gas as a percentage of total consumption by end-use sector in New York indicates the following: residential, 45%; commercial, 47%; industrial, 18%; power generation, 24% [based on net energy].[7]

The fastest growing gas consumption sector nationally and in the northeast has been gas for electric generation. In 2001, the New York Independent System Operator ("NYISO" or "New York ISO") recommended that between 5,000 and 7,000 megawatts (MW) of in-state generation was needed by 2008 to maintain reliability. More than 3,000 MW have been installed since then.

Tables 7 and 8 show New York's generating capacity mix as of January 1, 2005, as well as fuel mix based on actual energy provided during 2004 as reported by the New York ISO. The picture is less clear as gas consumption by power generators is classified as "gas only" and "gas & oil". Other reports, for example a 2004 study by the National Regulatory Research Institute ("NRRI") found that in 2004 natural gas made up over 25 percent of electricity generation in New York and that about 90 percent of New York City's generation used natural gas either as a primary or secondary fuel. According to the Northeast Gas Association, gas represents 26% of the electric generation mix.[8]

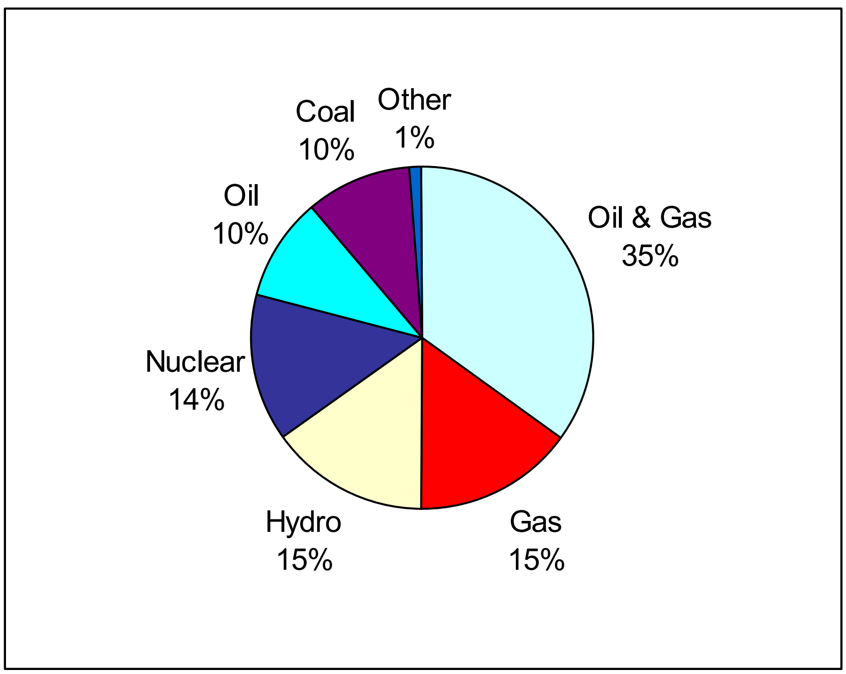
[7] New York State Energy Research and Development Authority (2004), Patterns and Trends: New York State Energy Profiles: 1989-2003
[8] Northeast Gas Association (May 2005), Northeast Natural Gas Update

7.3.1 Table 7. New York's Generating Capacity Mix (2005)

Energy Source	Share (%)
Oil & Gas	35
Gas	15
Hydro	15
Nuclear	14
Oil	10
Coal	10
Other	1
Total	**100**

Source: New York ISO 2005 Power Trends Report, April 2005

7.3.2 New York's Generating Capacity Mix (2005)



7.3.3 TABLE 8. ELECTRIC POWER INDUSTRY GENERATING CAPABILITY BY PRIMARY ENERGY SOURCE, 1993, 1997, AND 2002 (MEGAWATTS)

	1993	1997	2002	Annual Growth Rate 1993-2002 (%)	Share % 1993	Share % 1997	Share % 2002
Coal	4,275	4,252	4,144	−0.3	12.0	12.0	11.5
Petroleum.	5,156	4,749	3,550	−4.1	14.5	13.3	9.8
Natural Gas	5,222	3,548	3,253	−5.1	14.7	10.0	9.0
Other Gases	20	23	0	NM	0.1	0.1	0.0
Dual Fired	8,195	12,133	14,251	6.3	23.0	34.1	39.5
Nuclear	4,831	4,961	5,047	0.5	13.6	13.9	14.0
Hydroelectric	7,545	5,494	5,406	−3.6	21.2	15.4	15.0
Other Renewables	353	417	390	1.1	1.0	1.2	1.1
Total	**35,597**	**35,576**	**36,041**	**0.1**	**100.0**	**100.0**	**100.0**

Source: Energy Information Administration/State Electricity Profiles 2002

Natural gas is mostly used as a winter peaking fuel for electric generation in the state. The vast majority of new generating units being constructed and proposed are gas-fired with limited dual-fuel capability. In addition to significant gas price increase and volatility in the recent years, there have been several instances where generators were unable to receive gas and concerns over the reliability implications of the increasing use of gas-fired electricity generation are on the rise.

7.4 SERVICES

Iroquois Gas Transmission System, L.P

Through its subsidiary, Iroquois Pipeline offers Firm (RTS) and Interruptible (ITS) transportation services as well as balancing products through its Park and Loan Service. Firm capacity is made available through an Open Season. Interruptible transportation capacity is made available on a day-to-day basis as operating conditions permit. ITS capacity is always made available after firm (RTS) capacity, but before PAL transactions. If ITS capacity has to be allocated, it is allocated based on the highest percentage of the maximum commodity rate for the service being provided. When market conditions dictate, Iroquois considers a discounted rate on interruptible capacity to remain competitive.

Iroquois also offers a balancing service (Park and Loan service) on a first-come, first-served daily basis according to nominations it receives. The PAL service enables a shipper to borrow gas from or leave gas on the Iroquois system as operating conditions permit. Rates for this service are market-based and are structured to be competitive.

Since its inception in January 1996, the PAL service has been used in a variety of ways, which include:

- balancing to manage nominated vs. confirmed mismatches;
- balancing to manage intra-day swings in temperature and related demand requirements;
- balancing to manage instances where secondary receipt/delivery points are constrained;
- balancing to manage take-away restrictions at meters as a source of peaking supply.

Iroquois also offers an Extended Receipt / Extended Delivery Service which is available only to firm transportation capacity holders. Specifically, this service enables a Zone 1 only or Zone 2 only firm shipper to utilize a zone outside the shipper's primary contract path on a secondary basis. A shipper only pays when it uses the extended service and recourse or negotiated rates are available to the shipper. Although a shipper utilizing this service receives a lower priority to firm and secondary firm service, the shipper would receive a higher priority than it would under an interruptible service contract.

Empire State Pipeline-Intrastate (subsidiary of National Fuel & Gas Co)

Empire offers flexible nomination cycles including Timely Nomination Cycle, the Evening Nomination Cycle, the Intra-day 1 Nomination Cycle, and the Intra-day 2 Nomination Cycle.

The New York State Electric & Gas Corporation

NYSEG has a basic electric generation transportation service. This service is available to any new or existing dual-fuel electric generating facility with generating capacity of at least 50 Megawatts (MW) that has executed a Transportation Service Agreement with the Company for a term of not less than five (5) years.

The specific charges for service under this service classification include a contribution to overall system costs of $0.01 per therm; plus an amount of $.0ll per therm to cover marginal system costs that reflect the long-run incremental costs of building transmission and high capacity distribution pipelines; plus a Spark Spread Adjustment (“SSA”), which is initially set at zero (0), but which is then calculated on a quarterly basis to reflect five percent of the market “spark spread” between the cost of gas and the cost of electricity, per therm.

Customers of this service are required to transport and pay for a minimum annual quantity of no less than fifty percent (50%) of the generator’s maximum annual quantity.

7.5 STORAGE

According to the NY State Department of Environmental Conservation, total gas storage capacity in New York is 207 Bcf, with a working capacity of 97.8 Bcf and a maximum deliverability of about 1,927 MMcf/day[9]. A recent storage field addition to New York was provided via the Stagecoach project, with 13 Bcf of storage capacity.

Planned storage projects include Wyckoff Storage (approved by FERC on October 1, 2003), Seneca Lake II, and Tennessee's planned "Northeast ConneXion" in Pennsylvania, as well as other projects geared to serving the entire Northeast market.

LNG is another important part of the Northeast storage portfolio. Total LNG storage capacity in New York is about 3.4 Bcf.

7.6 JURISDICTIONAL POLICY

7.6.1 COST RECOVERY OF INVESTMENT ON INTRASTATE TRANSMISSION/STORAGE

The cost of investment on new gas infrastructure could be rolled-in or incremental. Individual circumstances determine the approved allocation method.

7.6.2 COST RECOVERY OF INVESTMENT ON INTERSTATE TRANSMISSION/STORAGE

Again, FERC's general rule on incremental/rolled-in pricing applies.

With respect to investment in gas infrastructure in New York, the FERC presided and rendered a decision in relation to the December 23, 2002 application by Wyckoff Gas Storage Company ("Wyckoff") seeking approval for a certificate authorizing the construction and operation of a natural gas storage facility in Steuben County, New York, to provide storage services under market-based rates. In its decision issued on October 6, 2003, the FERC granted the request and noted the significance of the project in terms of the growing demand for gas for electricity generation as follows:

> The Commission finds that the Wyckoff Storage Project will serve the public interest by providing firm and interruptible high-deliverability, single and multi-cycle natural gas storage service in interstate commerce, without significant landowner or environmental impacts. Moreover, this high deliverability storage service will further the development of the natural gas infrastructure necessary to support use of natural gas in connection with the growing electric generation market.

7.7 RECENT DEVELOPMENTS

Charles River Associates

The New York ISO along with the New York State Energy Research and Development Authority ("NYSERDA") funded a study, conducted by Charles River Associates in 2002, to examine the impact of increased demand for natural gas by electric generators on the state's electric power and gas pipeline infrastructures. The study applied an integrated model of the electricity and

[9] NYS DEC, *New York State Oil, Gas and Mineral Resources, 2003*

natural gas infrastructures for the Northeast and made several key findings and conclusions. The first finding was that it continues to be critical for generators to have the ability to burn oil even when gas supplies are adequate; oil storage should also be preserved to assure future reliability of the electrical system when gas cannot be delivered. The report projected that the expected additions to gas pipeline capacity should be adequate to meet the demands for gas by electric generators, provided the existing ability to burn oil is maintained. Second, the study concluded that the gas available for electric generation declines dramatically when cold weather reaches design winter conditions (that is, 10-15 percent colder-than-normal winter temperatures). Third, the incremental gas usage from new combined cycle facilities may not be as great as expected when taking into account the retirement or decreased use of less energy efficient, existing gas-fired units. Fourth, gas pipeline capacity, local fuel storage, and dual-fuel facilities are substitutable in achieving adequate electric-system reliability. Finally, electric generators lack economic incentives to procure firm gas transportation. As discussed above, as long as electric generators are able to purchase low-cost interruptible service during high profit-margin periods, namely, periods of a high spark spread, which typically are during the summer months when pipeline capacity is abundant, they will be content to continue to do so.

The report proposed that the incentives of gas pipelines and electric generators be "better aligned" to improve electric system reliability and efficiency.

NRRI

In April 2004 the NRRI released a report focusing on increased dependence on gas-fired generation in the Northeast.[10] Among its observations were the following:

- "Regional electric power operators face a potential dilemma in achieving the goals of low wholesale electricity prices and high reliability. The decisions of gas-fired generators to purchase non-firm gas transportation service and to not invest in dual-fuel capability are largely driven by economics. In some regions generators face intense competition and, thus, have a strong incentive to control their costs. More reliable electric service from gas-fired power plants would likely increase the generation costs of such facilities."
- "As underscored in this report, the potential problem posed by gas-fired generators is largely the responsibility of the regional electric system operator/planner, who must assess the presence of these generators on the system's reliability, particularly with regard to operational security."

New York ISO: 2003

In 2003, the market monitoring unit of the New York ISO reported the possibility of shortfalls in gas-delivery to gas-fired generators causing the loss of electric load and identified two options that it may want to consider to deal with the situation in future: (1) the requirement that generators procure firm service for some or all of their gas requirements and (2) the implementation of more stringent rules to ensure adequate dual-fuel capability on gas-fired units. The report predicted that natural gas prices in the state would be driven up if generators attempted to procure firm transportation service.

The New York ISO has expressed concern about interruptible service to electric generators jeopardizing the reliability of the state's electric power system. In addition, as in New England,

[10] NRRI, Increased Dependence on Natural Gas for Electric Generation: Meeting the Challenge, April 2004

the ISO has questioned whether adequate gas pipeline capacity exists to satisfy the demands of both electric generators and traditional gas utility requirements with firm supply during the winter months. Finally, the NYISO has expressed concern over the absence of dual-fuel capability for most new power facilities.

New York ISO: 2005 Power Trend

In its assessment of the near term reliability, the ISO stressed the importance of additional pipeline infrastructure in the future to deliver sufficient amounts of gas for electric generation. The NYISO said that to some extent, the problem has been ameliorated by the ability of existing gas-fired plants to run on dual-fuel. However, it stressed the importance of determining the extent of the dual-fuel supplies actually being kept at the plants and the capability of timely replenishment. It suggested that a market mechanism may need to be developed to ensure that an adequate amount of New York's gas-fired generation is dual-fired.

In its report on fuel diversity, the NYISO stated that the earlier assumptions about natural gas as a choice for new generation are increasingly changing as North America's sources of additional gas are proving finite. Plentiful additional supplies of gas are available from elsewhere in the world in the form of LNG, but increased dependence on LNG raises concerns about infrastructure, cartelization, energy security and the relationship between gas and oil prices. It added that to a great extent, natural gas will become subject to the same concerns as the country's growing dependence on imported oil.

The NYISO thus advises that the nation in general and the Northeast in particular, must fashion an effective fuel diversity strategy for dealing with the increasing use and dwindling domestic reserves of natural gas. Such a policy will have to include increased use of renewables, improved incentives for efficiency, and utilization of other domestic fuels.

8 GREAT BRITAIN

8.1 OVERVIEW OF THE ENERGY MARKET

Both the electricity and gas markets in Great Britain reflect the results of the privatization and market liberalization carried out over the past several years. The assets of the previous government owned natural gas and electricity monopolies have been privatized and now operate as an independent commercial enterprise. Originally the privatized entities operated as separate companies but on October 21, 2002, Lattice Group plc, the holding company for Transco which was the owner and operator of the natural gas transmission system in England and Wales, and National Grid Group plc, which owned and operated the electricity transmission and distribution system in the same area, merged under the name National Grid Transco plc ("National Grid"). This has facilitated some high level co-ordination between the two markets. Both transmission systems still function as regulated, natural monopolies, and each is operated on a day-to-day basis by subsidiaries of National Grid. Both the electricity and gas transmission systems have been fully unbundled with no involvement by their owners in either the supply or sale of the commodity involved beyond the normal balancing transactions required to ensure the reliable operation of the two markets.

For nine years the National Transmission System ("NTS") for natural gas in Britain operated under Transco's Network Code but the sale of four distribution networks by National Grid Transco in 2005 required a change in the contractual structure of the industry and the creation of the Uniform Network Code ("UNC") and short-form Codes for each transmission operator. The UNC is overseen by the Joint Office of Gas Transporters.

Similarly, from March 2001 to March 2005, National Grid operated the unbundled electricity system in England and Wales under the New Electricity Trading Arrangements ("NETA"). In April of 2005, the market was expanded to all of Great Britain and National Grid assumed the day-to-day operation of the electricity transmission networks owned by Scottish Power and Scottish and Southern Energy under the new British Electricity Trading and Transmission Arrangements or BETTA.

8.2 STATE OF GAS GENERATION

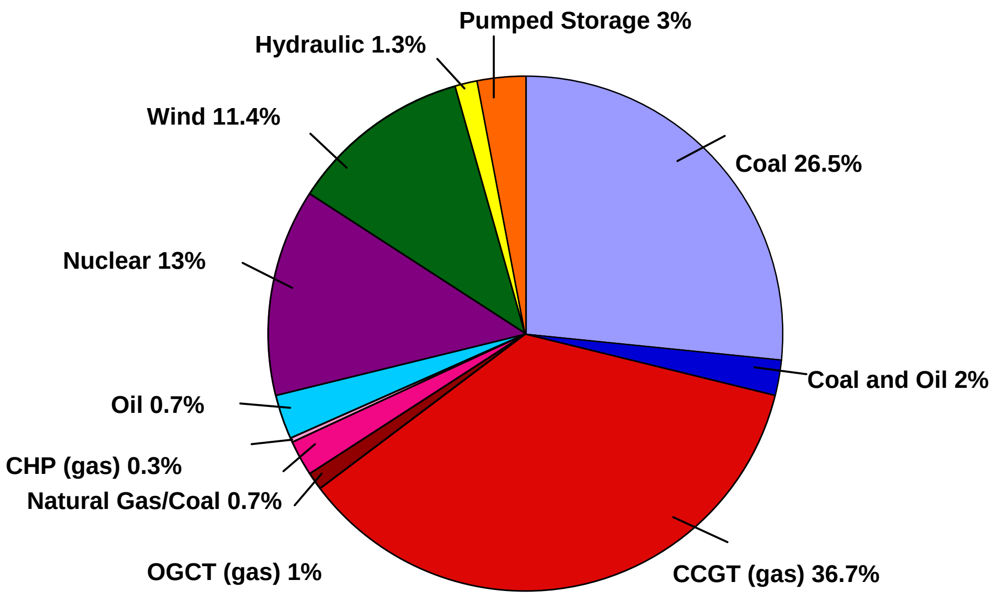
Once largely dependent upon coal as a generation fuel source, the market in Great Britain has become far more diverse with an increasing emphasis on natural gas and renewable sources, particularly wind. The "Great Britain Seven Year Statement" published by National Grid in May of 2005, provides the following information on the country's current mix of generation:

8.2.1 TABLE 9. BRITISH GENERATION BY FUEL SOURCE (2005)

Source	**Output Capacity (MW)**	**Proportion of British Supply (%)**
Coal	24,431.0	26.47
Coal / Oil	1,940.0	2.10
Coal Sub-Total	**26,371.0**	**28.57**
Combined Cycle Natural Gas Turbine (“CCGT”)	32,959.9	35.71
Gas & Open Cycle Natural Gas Turbine (“OCGT”)	967.0	1.05
Natural Gas / Oil	660.0	0.72
Natural Gas / Coal	1,984.0	2.15
Combined Heating and Power (“CHP”)	287.0	0.31
Gas Sub-Total	**36,857.9**	**39.84**
Oil	2,520.0	2.73
Nuclear	11,985.0	12.99
Wind	10,549.9	11.43
Hydraulic	1,239.5	1.34
Pumped Storage	2,744.0	2.97
Other	27.0	0.03
Grand Total	**92,294.3**	**100.00**

Source: National Grid, Great Britain Seven Year Statement, May 2005

8.2.2 Figure 6. British Generation by Fuel Source (2005)



It should be noted that the OCGT units listed in the above table were largely part of complexes with larger units powered by another fuel source and therefore are likely not operated on a frequent basis. Similarly, several of the facilities that burn natural gas can also switch to other fuels in the event of a shortage of natural gas during peak periods. The above sources are also augmented with interties with both the European mainland and Ireland. In addition, where necessary, National Grid indicates that some of the plants that have currently been mothballed can be reactivated.

While much of the thrust in recent years has been toward the use of natural gas as the fuel source for new generation and National Grid is predicting that there will be a significant increase in the level of gas fired CCGT generation over the next few years. However, natural gas prices have risen over the last few years and there are indications that production from the fields in the North and Irish Sea, which facilitated earlier increases in natural gas-fired generation, has peaked and may even be in decline. Offsetting this is the fact that additional supplies can be imported through pipelines from Norway and Belgium and potential increases in the importation of LNG. There is an existing LNG import terminal in the southeast of England and others have been proposed. Grain LNG, a subsidiary of National Grid Transco, recently announced that its new importation terminal on the Isle of Grain , which it says has the capability to import and process 3.3 million tonnes per year, representing about four per cent of the U.K.'s current annual gas demand, is now operational.

8.3 SERVICES

Large volume customers in Great Britain can either take service directly off of the NTS or from the distribution systems of the LDCs. Transco and various LDCs all have rates which anticipate their use by larger volume customers. Parties wishing to ship gas on the NTS must first obtain a licence from the energy regulator the Office of Gas and Electricity Markets ("Ofgem"). Transmission operators are expected to do business with any shipper that has obtained a licence from Ofgem as long as it meets the necessary financial requirements. According to the UNC, customers wishing to obtain transportation capacity do so through a series of capacity auctions which it describes as follows:

- Long Term Capacity: Auctions are held annually and make capacity available in quarterly segments for periods of up to fifteen years beginning two years after the auction.
- Medium Term Capacity: Annual auctions which make capacity available in monthly segments for periods of up to two years starting shortly after the auction is completed. Monthly capacity is also made available by way of monthly auctions for unsold capacity for the following month.
- Daily Capacity: Shippers are able to bid for additional firm and interruptible capacity which is deemed to be available on a daily basis.

Capacity can also be obtained from other shippers through an auction process that is facilitated under the UNC.

8.3.1 NOMINATION PROCESS

Shippers initially nominate for delivery points that are metered on a daily basis by 1:00 p.m. the day before the gas is to flow. Transco estimates the demand at the other delivery points by 2:00 p.m. and shippers nominate with their suppliers for the entry points by 4:00 p.m. However, with Transco's permission, shippers can renominate up until 3:59 a.m. the following day. Shippers also have access to the daily capacity market and on-the-day commodity market to make up for any differences between their nominations and their requirements.

8.3.2 COSTS FOR NATURAL GAS TRANSMISSION FACILITIES

The portion of the costs incurred by Transco related to the connection of a new customer, and which that customer must pay, is dependent upon the location of the underlying facilities. Transco defines facilities required to permit the connection of specific new customers, to permit an increase in the requirements of existing customers or to allow the conversion of interruptible requirements to firm as "specific reinforcements". The recovery of the costs of these specific reinforcements is dependent upon their location with respect to the "system charging point" which is defined as the closest economically feasible point on the National Transmission System which is deemed to have enough capacity for the new load disregarding existing loads. Customers must pay the costs, including overheads, of specific reinforcements downstream of the connection charging point but are not charged directly for the costs upstream of that point. The costs for connecting entry or storage facilities to the NTS are not charged directly to the customer but are taken into account in the auction price for any related capacity.

8.4 STORAGE

There are three types of storage facilities in place in Britain; LNG, salt cavern and depleted reservoirs with the later having by far the largest capacity. Under Directive 2003/55/EC from the European Parliament, which governs the operations of natural gas transmission and distribution pipelines and storage systems, operators of those facilities must make them available to third party users on a non-discriminatory basis unless granted an exemption by a competent authority, which in the case of Great Britain is Ofgem. The exemption must also be accepted by the European Authority. The criteria for receiving an exemption are as follows:

- the investment must enhance competition in gas supply and enhance security of supply;
- the level of risk attached to the investment is such that the investment would not take place unless an exemption was granted;
- the infrastructure must be owned by a natural or legal person which is separate at least in terms of its legal form from the system operators in whose systems that infrastructure will be built;
- charges are levied on users of that infrastructure;
- the exemption is not detrimental to competition or the effective functioning of the internal gas market, or the efficient functioning of the regulated system to which the infrastructure is connected.

According to an Ofgem decision dated July 5, 2005, several of the smaller storage facilities have applied for and been granted exemptions from the provisions of the Directive although Centrica Storage Limited’s Rough facility, the largest in the country, and Scottish and Southern Energy’s Hornsea facility, which is also one of the largest, are still required to provide third party access. Several other facilities currently under development have not yet applied.

Transco LNG Storage, a ‘ring-fenced’ Transco subsidiary, operates four LNG facilities. Although it is exempt from the Directive, under the terms of its licence and the Uniform Network Code, each year it offers up for auction storage capacity and/or tanker filling slots at its facilities. Use of the facilities is however subject to certain constraints in order to allow Transco to maintain service to certain load centres near the terminal points of its facilities.

8.5 JURISDICTIONAL POLICY

The distribution and sale of natural gas and electricity in Great Britain is regulated by Ofgem. Ofgem describes its role as protecting and advancing the interests of consumers by promoting competition where possible, and through regulation only where necessary. Ofgem operates under the direction and governance of the Gas and Electricity Markets Authority, which makes all major decisions and sets policy priorities for Ofgem. Ofgem has acted proactively to promote competitive markets, including those for power, and has not hesitated to take corrective action where it thought parties were acting in a manner that would hinder those markets.

One of the impediments that gas-fired generation face in Great Britain is Government policies that have supported and provided financial incentives for renewable sources of power. These, aided by the rising natural gas prices, have resulted in a significant increase in the development of wind. The Department of Trade and Industry of the British Government, has set its

Renewables Obligation target for licensed electricity at 10.4% for 2010/2011 and at 15.4% for 2015/2016.

8.6 RECENT DEVELOPMENTS

While there is no direct co-ordination between the natural gas and electricity markets, National Grid, under the auspices of Ofgem and pursuant to its licence conditions, annually publishes a series of reports which in fact go a long way towards accomplishing the same goal.

National Grid's forecast of conditions for the natural gas industry are set out in Transco's "*Ten Year Statement*" which provides a ten-year forecast of transportation system usage and likely system developments that can be used by companies who are contemplating connecting to its system or entering into transportation arrangements, including potential and existing generators, to identify and evaluate opportunities. The Statement forms the basis of Transco's industry wide consultation process. It contains essential information on actual volumes, the process for planning the development of the system, including demand and supply forecasts, system reinforcement projects and associated investment.

The companion document for the electricity industry is the "*Great Britain Seven Year Statement"* which was published for the first time this year by National Grid Company plc. Similar documents had been prepared in previous years by National Grid and the two Scottish transmission licensees, SP Transmission Ltd and Scottish Hydro-Electric Transmission Ltd. National Grid states that the document is designed to assist existing and prospective new users of the Great Britain transmission system in assessing opportunities available to them for making new or additional use of the Great Britain transmission system in the competitive electricity market. This document provides a wide range of information relating to the transmission system in Great Britain including information on demand, generation, plant margins, the characteristics of the existing and planned Great Britain Transmission System, its expected performance and capability and other related information.

Bringing the two markets together is another document, which is prepared by National Grid and is classified as a consultation. This document looks at potential supply and demand scenarios for the following winter for both the natural gas and electricity markets and examines the implications of the conditions in one market on the operation of the other.

9 APPENDIX

9.1 APPENDIX A. SCHEDULES AND SERVICES PROVIDED BY MAJOR UTILITIES IN ALBERTA, CALIFORNIA, ILLINOIS, MICHIGAN AND NEW YORK

UTILITY	SCHEDULES/SERVICES
Alberta	
Nova Gas Transmission Ltd	Facilities Connection Service
EnCana Gas Storage	A multi-time nomination schedule with intra-day nominations and the possibility of multiple storage cycles
ATCO Midstream Carbon Storage	Multi-cycling and intra-day nominations
California	
El Paso Natural Gas	Firm transportation service (FT-1 and FT-2) Interruptible transportation service (IT-1) Interruptible parking and lending service (PAL)
Mojave Pipeline Company	Interruptible authorized loan service (ALS-1) Parking service (APS-1)
SoCalGas	Electric generation rate GT-F5 GN-10 gas rate is a 3-tier gas rate that includes both transportation and the cost of natural gas
PG&E	Schedule G-EG for electric generators -A “Timely Nomination” An “Evening Nomination” An “Intraday 1 Nomination” An “Intraday 2 Nomination”
SoCalGas Storage	Basic Storage or BSS

	Long Term Storage or LTS Transaction Based Storage or TBS
Illinois	
ANR	Firm transportation service FTS-3
Panhandle Eastern	Hourly Firm Transportation Service Enhanced Firm Transportation Service Quick Notice Transportation Service
Midwestern Gas	Firm Transportation Service
Peoples Energy	Contract Service for Electric Generation Standby Service
Northern Illinois Gas Company	Rate 11 includes the provision of gas supply Rate 81 is a transportation rate Large Volume Transportation Service Rate 77
Panhandle Eastern	Flexible Storage service Parking and Loan Service
Michigan	
ANR	FTS-3 (firm transport) ITS-3 (Interruptible transport) Premium no-notice service
Panhandle Eastern Pipe Line Company, LP	Standard FT and IT services Hourly Firm Transportation Quick Notice Transportation Enhanced Firm Transportation Gas Parking Service Flexible Storage Service No Notice Service Flexible Field Zone Firm Transport

	Intraday Gas Parking Service Delivery Variance Service
New York	
Iroquois Gas Transmission System, L.P	Firm (RTS) and Interruptible (ITS) transportation Park and Loan Service
Empire State Pipeline-Intrastate	Timely Nomination Cycle Evening Nomination Cycle Intra-day 1 Nomination Cycle Intra-day 2 Nomination Cycle
The New York State Electric & Gas Corporation	Basic electric generation transportation service

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