COMPETITION IN GAS PIPELINE MARKETS:

INTERNATIONAL PRECEDENT FOR REGULATORY COVERAGE DECISIONS

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Prepared for:

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Introduction and Overview

The National Competition Council (NCC) is in the process of considering whether the Eastern Gas Pipeline (EGP) owned by subsidiaries of Duke Energy International (Duke) should be "covered" under the National Third Party Access Code for Natural Gas Pipeline Systems. The application for coverage of the EGP was filed by AGL Energy Sales and Marketing Limited, the current majority owner and operator of the EAPL pipeline. EAPL is the incumbent pipeline serving NSW. EAPL has indicated that it may apply to the NCC for revocation of coverage. Coverage under The Code would imply that the EGP's pricing and services would be governed by the regulatory regime specified in The Code, under specific rules promulgated and administered by the Australian Competition and Consumer Commission (ACCC). As an alternative to such regulation, Duke has filed an Undertaking to the ACCC under section 44ZZA of Part IIIA of the *Trade Practices Act*, which sets out for ACCC approval Duke's "voluntary" third party access arrangement under which it would operate if not covered by the Code.

The NCC's coverage decision under The Code requires it to determine, in part, whether coverage, and thus "access (or increased access) to Services provided by means of the Pipeline, would promote competition in at least one market (whether or not in Australia) other than the market for the Services provided by means of the Pipeline."

The NCC has asked us to review and report on international precedent and theoretical literature that might assist it in addressing this question. This draft reports on our initial review of the frameworks and analytic procedures that regulators use in the United States and Canada to make similar decisions. Included also are descriptions of some cases that have received detailed regulatory scrutiny. We have focused initially on North America because it has the richest history in considering pipeline competition in the context of proposals to relax or modify the degree of regulatory scrutiny. The situation in Europe is much less developed at the moment, in the sense that the European Union's *Gas Directive* is currently just in the process of being implemented by Member States. Consequently, few established guidelines are yet in place for determining the degree of regulatory scrutiny required for the implementation of the Directive.[1]

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[1] We have recently prepared a report for the European Commission on guidelines for the implementation of the European Gas Directive: "Methodologies for Establishing National and Cross-Border Systems of Pricing of Access to the Gas System in Europe," Report to the European Commission by *The Brattle Group* (Paul Carpenter, Carlos Lapuerta and Boaz Moselle), February 2000. (Report is available on the EC's website or at www.brattle.com).

This report has four main sections after this introduction. First, we summarise what we conclude from this review, including some further issues that the NCC may wish to consider in its EGP coverage decision that are to some extent issues of first impression, i.e., where overseas experience may not be a good guide.

In Section Three we review the US and Canadian experience in new pipeline project certification. The economic conditions required for new pipeline authorisation in North America are perhaps the closest analogy to the question of whether a new pipeline such as EGP should be covered, given its potential affect on competition in upstream or downstream markets.

In Section Four we review the US precedent concerning whether existing (incumbent) gas pipelines should be allowed to charge "market-based rates" (i.e., tariffs not constrained by regulatory price caps). This is analogous to considering whether coverage under the Code should be lifted on an existing pipeline, such as EAPL. Here, we first summarise U.S. policies on this issue and show how U.S. regulators decide on whether gas transmission and electric generation should be allowed to charge market-based prices We include experiences in the electric generation industry to show that when an active market develops or is developing, U.S. regulators tend to encourage market-based rates for sellers that do not possess market power.

The fifth section involves the issue of whether privately negotiated long-term contracts (such as might be negotiated by EGP) may be relied on as protection against market power abuses. We outline the theoretical arguments for how competition might be essential even after customers have signed long-term contracts. This is especially the case when large capital investments are at stake. We review the academic literature on this topic and discuss how it might be relevant to the analysis of EGP and EAPL applications.

Summary and Issues for Further Consideration

General Comments

1. There is no precisely comparable precedent, internationally, for the analysis that the NCC must perform in the case of EGP (and potentially EAPL) coverage. Most natural gas pipelines worldwide are covered by some form of regulatory or negotiated access arrangement that dictates terms and conditions of service, maximum prices, and information disclosure requirements. International precedent thus involves an implicit assumption about the continuing effectiveness of regulation under approved

access arrangements, at least as applied to the provision of firm transportation services.

2. Most organised international gas markets also start from a position of greater inter-pipeline competition either in origin or destination markets than exists currently in Australia, with a greater diversity in third-party holdings of pipeline capacity. Most supply basins in North America and Europe have more than one pipeline accessing them. Many destination markets have multiple pipelines serving them. Despite the greater "thickness" of these markets, pipelines in these jurisdictions are still considered to have natural monopoly characteristics and are regulated with respect to price and terms and conditions of service.

3. Regulatory "relaxation" is thus rarely, if ever, characterised as a waiving of open-access requirements. Instead, the debate is usually over the amount of pricing and service flexibility that may be granted to pipelines in the context of the existing access and regulatory arrangements. Thus, the effectiveness of the existing access arrangement becomes an important analytical issue.

4. Nonetheless, there is fair amount that can be learned from how various jurisdictions have analysed competition in pipeline markets in these cases. In reviewing this precedent, it is useful to distinguish between policy toward *new* pipelines versus *existing* pipelines. This is because the nature of competition between pipelines changes materially once the new pipeline investment is buried in the ground.

New Pipelines

5. North American regulators have become comfortable with using "let the market decide" tests for new pipeline authorisation. Such policies are not purely *laissez faire*, however. Much of the debate and resulting practice has to do with various tests to ensure that the nature of the competition to build new pipelines is fair and that the projects are not dependent on cross-subsidies from third-parties for their market success (i.e., that the project sponsors are "at risk."). An example of a cross-subsidy would be an uneconomic bypass of an existing pipeline, where existing administered prices are in excess of the stand-alone cost of serving the bypassing customers. The most popular tests relied on by regulators for demonstrating market support are in the form of long-term contracts from shippers committing to the new pipeline, or a demonstration that the pipeline sponsors are fully at risk financially for the project's consequences.

6. The prices and terms and conditions of service that result from such "pre-construction" competition become by default the regulated tariffs for the new pipelines.

7. While the showing of long-term contracts (by which shippers are assumed to be able to protect themselves from post-construction market power) is still an important part

of current policies, there is also considerable scrutiny of contracts with affiliated companies. Such contracts are generally not considered as proof of competitive market support, but may be acceptable if the project sponsors are fully "at risk."

8. These policies are rooted in concerns that there may be inefficient incentives to build excess or untimely capacity, in order to capture a future competitive advantage, under a purely *laissez faire* policy. Examples of such inefficiency have been witnessed in North America.

Existing Pipelines

9. The closest analogy to "revocation of coverage" in North America have been proposals by existing pipelines (and electric power companies) to charge "market-based rates." Such proposals have asked regulators to permit existing lines to charge unconstrained rates, subject to regulatory complaint procedures.

10. US regulators have developed procedures to evaluate the competitive implications of market-based rates. These procedures employ traditional economic methods used in competition law and merger cases, including product and geographic market definition, concentration measures, and investigation of the potential for anti-competitive behaviour in relevant markets.

11. The developed standards are relatively strict, mirroring US antitrust enforcement agency "guidelines." For example, origin and destination markets are considered concentrated at Herfindahl (HHI) index levels above 1800, or approximately five equally-sized firms. This threshold is very hard to beat even in the relatively "thick" US market. Consequently, market-based rates have typically not been granted for the basic services of existing pipelines. Instead, it has more commonly been applied to various services where entry is relatively easy and does not require significant sunk investment, such as marketing and ancillary services provided by market centres or "hubs." Market based or "negotiated" rates have also been contemplated where there is a "recourse" for the customer to take basic firm transportation service at the capped, regulated rate.

Theoretical Literature

12. There is a fairly large economic literature on the use of long-term contracts in industries characterised by a high degree of "asset-specific" sunk investment. This literature emphasises the role of long-term contracts in preventing opportunistic "hold-up" problems occasioned by sunk investment. This literature obviously supports a policy that relies on the ability of pipeline shippers to protect themselves by contracts in advance of new pipeline construction.

13. We also review some of the literature that developed in the early 1990's employing "experimental economics." These studies attempted to determine, based on

experimental simulations of pipeline markets, normative standards for determining how many players (pipelines or holders of pipeline capacity in a trading market) were necessary to ensure competitive outcomes. Our impression is that there are serious limitations to these studies that make them difficult to rely on in interpreting real-world gas markets. However, normative behaviour models of gas and electricity markets that attempt to simulate oligopolistic behaviour are growing in use in competition law and regulatory matters. For example, such models are now increasingly used in North America to analyse the competitive effects of mergers involving electricity and gas companies.

Competition From New Pipelines and Regulatory Certification Policy

In this section, we review the development andcurrent state of policies in North America for the authorisation of new gas pipelines. These policies illustrate the way competitive contracting and "at risk" conditions are taken into account by the regulatory authorities, and their use in establishing future prices and terms and conditions of service on new pipelines analogous to the EGP.

U.S. Policy for Authorisation and Pricing of New Pipeline Projects

Several different approaches have formed the basis of certification policies for new pipeline projects in the United States over the last twenty years. The historical approach employed drawn-out public hearings, in which interested parties presented evidence before an administrative law judge (ALJ) on the costs and benefits of the project under scrutiny. The ALJ would make a certification recommendation to the regulatory agency based on a weighing of this evidence.

Dissatisfaction with the ability of the regulators to make timely certification decisions led to more stream-lined approaches in the late 1980's. One approach involved the imposition of contract requirements to demonstrate sufficient market support before new capacity would be added. An alternative approach abandons the contract requirement, but requires a showing that project investors are willing to bear the full project risk and forego the opportunity to recover potential losses from regulated customers in the future. Below we describe the evolution of U.S. certification policy over time, showing how it has employed these concepts in different degrees.

U.S. certification policy for gas pipelines has traditionally been governed by Section 7(c) of the *Natural Gas Act*, although Section 7(c)'s rather broad language has permitted an evolution of different regulations and procedures over time. Section 7(c) requires that new projects obtain a certificate of "public convenience and necessity" from the Federal Energy Regulatory Commission (FERC). The certificate decision is typically initially made by an administrative law judge who must consider market demand, environmental effects, economic, operational and competitive benefitsof the proposed new project.

For many years, FERC held public hearings where supporters and opponents of new projects argued about these considerations in front of the administrative law judge. The FERC subsequently formalised its policy concerning the proposed demand and the economic benefits of new pipelines. The FERC imposed a rule that required all applications for new pipeline capacity to show contracts covering at least 25 percent of the proposed capacity. In addition, FERC stated that its concerns about the demand and economic benefits of a new pipeline would be allayed if an applicant showed 10-year firm contractual commitments for 100 percent of its capacity or if it showed that revenues under contracts would exceed costs. Alternatively, FERC would be satisfied if the project sponsor assumed the entire risk of losses from the project. If, however, a project could not obtain the requisite contracts, then it would have to persuade the ALJ that prospective future revenues would exceed costs.

The policies described above generally applied to new, "greenfield" pipeline projects. Expansions of existing pipelines presented further problems because of the potential to capture economies of scale in pricing. In 1995,[2] the FERC issued an Order determining the appropriate pricing for expansions of existing pipelines. Generally, when the cost impact of the new facilities would result in a (cost-based price) increase of less than five percent,[3] then the FERC favoured averaging new costs with existing costs to determine new prices. The resulting price is referred to as "rolled-in."[4] A pipeline could also "incrementally price" its expansion service based on its incremental costs if the resulting price would be higher than its existing applicable price. (Charging an incremental price means that a new pipeline would establish a price for the customers on its existing pipelines separately from a price for the customers on its new facilities.) Conversely, the FERC would *not* allow incremental pricing if the resulting price was lower than the existing price. The regulators have generally taken the view that existing customers should be able to share in the scale economy benefits created by the expansion of an existing system.

Recent Policy Changes on Authorisation and Pricing of Pipeline Projects

In September of 1999, FERC issued a new policy that eliminated the previous 25 percent minimum contracting rule. The new policy requires a project sponsor (and its new customers that might commit to the project by long-term contract) to take full responsibility for the risks of under-utilised new capacity and not shift the risks to third parties such as customers on competing pipelines. Although the FERC has not specified a standard method for risk-sharing, a proposed pipeline can negotiate with its customers regarding what would happen to their respective prices if the pipeline were under-utilised. Essentially, the applicant must now either bear the entire financial risk or share the risk with its customers by negotiating in advance an agreed price.

The FERC no longer requires an applicant to present contracts for any specific percentage of the new capacity, but any signed contracts or precedent agreements for the capacity would still constitute significant evidence of demand for the project. Applicants can continue to submit precedent agreements, demand projections, potential cost savings to consumers, or other evidence supporting the financial viability of the proposed project.

In addition to evidence of financial viability, the new policy also requires an applicant to demonstrate that public benefits from the project outweigh any adverse effects. Some

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[2] FERC Order PL94-4-000, May 31, 1995.

[3] Some system benefits would also need to accompany the price increase.

[4] Statement of Policy, 88 FERC 61,227, September 15, 1999, p. 15.

examples of potential benefits are: meeting unserved demand, eliminating bottlenecks, opening access to new supply sources, lower costs to consumers, providing new interconnects that improve pipeline network, providing competitive alternatives, increasing electric reliability, and advancing clean air objectives. Examples of potential negative impacts include: high environmental costs, potential excess capacity (which could affect existing pipelines and customers as well as new ones), and the potential for unnecessary exercise of eminent domain to obtain rights-of-way. To gain regulatory approval, applicants are encouraged to submit applications designed to avoid or minimise adverse effects on relevant interests including effects on existing customers of the applicant, existing pipelines serving the markets and their captive customers, and affected landowners and communities.

The elimination of the specific contract requirement also reduces the potential problems associated with lack of arm-length contracts for pipeline capacity. In the past, applicants might have used contracts with their affiliates to satisfy the contract threshold. In past years, the regulator gave equal weight to contracts between an applicant and its affiliates, and an applicant and unrelated third parties, and did not "look behind" the contracts to determine whether the customer commitments represented genuine growth in market. But using only contracts with affiliates to prove demand can cause problems when affiliates do not really need all of the contracted capacity. In such a case, project costs might be shifted to other customers after project construction. Under the new policy, if contracts were presented with an application, then the FERC would consider agreements with multiple non-affiliated customers to present a greater indication of market support than a project with only agreements with affiliated companies. Since the new FERC policy seeks to prevent existing customers from cross-subsidising the new projects, and to ensure that project sponsors bear all remaining financial risks, it really does not matter if the contracts are with affiliates.[5]

As a general rule, the FERC does not adopt a bright line standard of how to weigh the benefits against the costs of a particular project. Instead, it suggests that adverse impacts of a project on a particular interest could be offset by the public benefits from the project. The FERC will evaluate each case individually. Included in this evaluation could be the issue of whether the pipeline would promote competition in upstream and downstream markets.

Pricing of New Pipeline Services

FERC's general policy is that prices must be "just and reasonable" and must be made available in a non-discriminatory manner. Its new policy requires a new pipeline project to

[5] Statement of Policy, 88 FERC 61,227, September 15, 1999, p. 25.

price its services *incrementally* and not shift its financial risks to existing customers.[6] Thus, new pipeline projects and any new customers who agree will bear the risk of under-utilised new capacity. New customers who elect to share that risk can specify (in a contract) what will happen to their prices and volumes under specific circumstances. Similarly, the risks of construction cost over-runs also should be apportioned between the pipeline and its new customers in their service contracts. Basically, existing customers should not subsidise new entrants and should not bear the cost of unused capacity that results from a competing project that might be not financially viable after the fact.[7] The FERC takes the view that incremental pricing sends the correct price signals for new entry and provides incentives for efficient project sizing and timing.

Cost and Benefit Analysis

In evaluating pipeline projects, the FERC will consider the amount of public benefits compared to any adverse effects of a proposed project. Specifically, it will consider the interests of applicant's existing customers, competing pipelines and their captive customers, and the interests of landowners and surrounding communities. In the past, the FERC did not deny applications on the grounds of the possible economic impact of a proposed project on existing pipelines serving the same market or on the existing pipelines' customers. With the new policy, their interests will be taken explicitly into consideration.

Under FERC's new policy, the amount of evidence necessary to establish market support for a proposed pipeline project will depend on the potential adverse effects of the project on the relevant interests mentioned above. Thus, projects that would serve new demand might not need to show as many public benefits as those that supply markets served by existing pipelines.[8] Thus, if the applicant is willing to bear the entire risk of the project, and not cause potential harm to third parties, then the FERC's certification requirements are not very stringent.

If an applicant would cause adverse impacts on customers of another pipeline, then the applicant must show evidence of strong benefits to consumers, such as lower rates for the customers to be served. The FERC may also consider how the proposal would affect the cost

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[6] There are exceptions to this incremental pricing policy, such as in cases of inexpensive expansions that is made possible because of earlier costly construction, where a pipeline has vintages of capacity and if some customers have the right of first refusal to renew their expiring contracts. Customers could be allowed to renew their contracts at their original contract rate except when the incremental capacity is fully subscribed and there are competing bids for the existing customers' capacity. In that case, the existing customer could be required to match the highest competing bid up to a maximum price set at either an incremental rate or a rolled-in rate in which costs for expansions are accumulated to yield an average expansion price. Foster Report No. 2251, September 16, 1999, p. 3 or Statement of Policy, 88 FERC 61,227, September 15, 1999, p. 20.

[7] Statement of Policy, 88 FERC 61,227, September 15, 1999, p. 21.

[8] However, the FERC did not clarify what constitutes "a new, previouslyunserved market".

recovery of the existing pipeline, particularly the amount of unsubscribed capacity that would be created and who would bear the costs associated with this "stranding." In such cases, the FERC would require evidence of benefits to be more specific and detailed than the generalised benefits of increasing competitive alternatives. While the policy does not focus on protecting incumbent pipelines from the risk of losing market share to a new entrant, it simply takes that impact into consideration when evaluating the project for certification. Although the captive customers of existing pipelines can be asked to pay for theunsubscribed capacity under the current pricing scheme for gas pipelines, the FERC indicates that it would not permit all costs resulting from the loss of market share to be shifted to captive customers.

Analytic Steps

In evaluating new pipeline projects or expansion projects, the FERC follows two steps. First, it attempts to evaluate whether the project can proceed without subsidies from existing customers. This usually means that the project would be incrementally priced if it were an expansion of an existing pipeline. Second, the FERC determines whether the applicant has made efforts to eliminate or minimise 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. Accordingly, the FERC evaluates the efforts made by the applicant and assists the applicant in finding ways to mitigate the effects. Because this policy is relatively new, few guidelines or case precedent are available for the quantifying of these costs and benefits.

Canadian Policy for Authorisation and Pricing of New Pipeline Projects

New pipeline projects in Canada must obtain a certificate of "public convenience and necessity" from the National Energy Board ("NEB"). The NEB would assess and issue certificates based on each project's environmental impact, economic feasibility, potential commercial impact, socio-economic and land issues, engineering and safety matters, tariffs, and the form of regulation.[9] Public hearings are allowed for all certification applications, and the NEB considers the objections of any interested person that it considers relevant.

Typically, the NEB has required a showing of firm commitments on new pipelines before approving the projects. This process is used to ensure that new pipelines and their customers are responsible for the financial and economic viability of the new pipelines. Pipeline sponsors can negotiate prices with their customers but the settled prices would be based on the costs of providing the services and must be put on record with NEB. Regarding the risks of under-utilisation on existing pipelines caused by the new projects, the NEB has made

[9] All gas pipelines are categorized to be one of two groups of companies, Group 1 and Group 2. The size of the pipeline and the number of associated shippers generally determine the form of regulation or which group it belongs to; large pipelines belong to Group 1 and smaller pipelines belong to Group 2. The NEB requires ongoing financial monitoring for Group 1 pipelines and requires a lower level of regulatory monitoring for smaller pipelines, generally on a complaint basis.

existing pipelines and their captive customers responsible for any lost revenues associated with under-utilised facilities. This means that the captive customers would pay for at least a portion of the costs of under-utilised pipelines. In response to the changing dynamics in the North American gas market, the largest pipeline in Canada, TransCanada, recently requested NEB approval of greater pricing flexibility for its interruptible and short-term firm transmission services.[10]

Recently, for example, a new pipeline requested (and received) regulatory approval of a pricing scheme referred to as Authorised Overrun Service (AOS). Under AOS, the pipeline would allocate all of the spare capacity (which varies over time) to firm service shippers according to each shipper's contracted firm service volumes.[11] There would be no charge for moving gas under this service other than the fuel charge. The pipeline submitted that this service would put the control of the available capacity in the hands of the shippers. This service also would allow the pipeline to allocate all of the pipeline's fixed costs to firm service shippers and only market interruptible service when capacity is not used up in the AOS. Since the firm service shippers would be paying for all of the fixed costs of the pipeline through their demand charge payments, they essentially have the first right of refusal for all of the pipeline's capacity. The transportation rights for AOS would be tradable on a secondary market and thereby provide additional flexibility to the shippers.[12]

Here, we will focus on Canadian new pipeline authorisation procedures, and when they rely on market-based decisions as opposed to detailed regulatory scrutiny of new pipeline projects.

Economic Feasibility Assessment

Under the economic feasibility assessment, the NEB reviews the availability of gas, the existence of markets (actual or potential), the economic viability of the pipeline, the financial

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[10] Application to NEB for Amendments to the IT and STFT Toll Schedules contained in TransCanada's Gas Transportation Tariff, October 29, 1999. In its application, TransCanada requested for approval a minimum price for both the IT and STFT service that is equal to 0.65 times the 100 percent load factor daily equivalent of the FT toll for the relevant path or segment on theTransCanada system. This is a change from the current minimum price of 1.0 times the 100 percent load factor for STFT and 0.5 for IT. In addition, it is prepared to accept a cap on these prices of 1.25 time the FT toll during the November to March winter period, and 1.00 times the FT toll during the April to October summer period.TransCanada reasons that there is significant amount of excess capacity and moving the price below the total cost level provides benefits by allowing the pipeline to capture markets that would otherwise be entirely lost.

[11] Volumes are allocated to the firm service shippers according to each shipper's contracted firm service volume, up to a maximum of 10 percent of each shipper's contracted demand quantity.

[12] Reasons for Decision, Alliance Pipeline Project, National Energy Board, GH-3-97, November 1998, p. 81.

responsibility and financial structure of the project sponsors, and any public interest that may be affected by the application.

The NEB is required by Canadian law to evaluate the *availability of gas supply* to a proposed gas pipeline project. This requirement does not mean that the NEB must be assured that there will be adequate gas supplies to keep a pipeline project full at all times. Rather, the NEB must be satisfied that there is a reasonable expectation that adequate supplies of natural gas will be available so that the facilities can be justified over the economic life of the project. Although the NEB does not necessarily rely on shippers to contract long-term sources of supply at the outset of the proposed project, it does consider shipper commitments to long-term transportation contracts as strong evidence that an adequate supply will be available to the pipeline project. If the applicant makes a credible case that the overall supply will be sufficient, on a long-term basis, to sustain a reasonable utilisation rate on the proposed pipeline and on other pipelines that transport gas from the same region, then the NEB deems the gas supply adequacy standard to have been fulfilled.

The applicant needs to perform *a market analysis* to convince the NEB that customer demand will be sufficient to support the project. The applicant typically submits a market demand forecast that shows the market potential both in the near-term and in the longer-term (of 15 to 20 years) either by using analysis from regulatory agencies or from another unbiased third party. Several applicants have stated in their applications that they and their shippers would take the financial risks with respect to any unutilised capacity on their pipelines. However, under the current pricing design, costs associated with the displacement of capacity on an existing pipeline is typically *not* the responsibility of a new pipeline.[13]

For *economic viability or feasibility*, the NEB recognises that with a pipeline addition, the overall available capacity may exceed the ability or willingness of producers to supply gas at the prevailing market prices for some time immediately after the new pipeline is constructed. However, the NEB still considers a project economically feasible if the shippers support the project by signing long-term contracts for a significant portion of the new pipeline. On a case-by-case basis, the NEB may require an applicant to identify shippers that have made contractual commitments and to make the details of their commitments available to the public.

For *project financing* information, the applicant should provide a proposed capital structure for the project and demonstrate to the NEB its ability to secure financing. When shippers make long-term commitments by signing transportation contracts, the NEB assumes that the shippers have decided that these commitments constitute the best use of their available capital. The NEB regards these commitments as sufficient evidence of financial support for the project.

[13] The NEB rejected proposals that would have required a new pipeline to set aside a contingency fund to pay for under-utilisation of existing pipelines. Reason for Decision Alliance Pipeline Ltd. GH-3-97, November 1998, p. 36 and 39.

Commercial Impact Assessment

For the commercial impact assessment, the applicant needs to provide evidence to the NEB of the new project's potential impacts on third parties. The potential beneficial impacts could be the increased choice and competitive benefits to parties other than the shippers on the proposed pipeline. A potentially negative impact could be the stranding of capacity on existing pipelines that could create financial hardship for their shareholders and/or their customers. The NEB then examines how the proposed project would impact overall competition in the gas market and more specifically how it might impact the "netback" prices received by gas producers.[14] We summarise here Canadian evaluation procedures for market competition and impacts on existing pipelines.

NEB certification decisions apparently do not depend on quantification of competitive benefits from applicants. Instead, the NEB believes that if producers and (regulated) local distribution companies support a project, then they are demonstrating their desire for choice and competition. The NEB would conclude that a projectwell-supported by producers and local distribution companies must bring long-term value to the Canadian gas industry.

The rate structure for gas pipelines in Canada allows pipeline companies to recover from their customers those costs associated with lower utilisation of existing pipelines as a result of construction of new pipelines. The NEB believes that the potential for duplication of facilities is inherent in the nature of competition; if commercial negotiations do not completely eliminate potential duplication, then it will likely be due to the parties' judgement that they are willing to compete in certain areas. The NEB views that duplication that results in beneficial competition may be considered to be in the public interest. The NEB has not, so far, held applicants responsible for the potential of stranding competing pipeline's assets, although any party so harmed is free to bring such a case requesting relief.

Traffic, Tolls, and Tariff

As in the U.S., Canadian authorities require that all prices charged by natural gas pipelines be "just and reasonable" and that the associated services must be made available in a non-discriminatory manner. Under its guidelines, the NEB allows pipelines and their shippers or customers to negotiate prices. The NEB considers the negotiated settlement process as a means for pipeline companies and interested parties to resolve issues and agree on tolls and tariffs without resorting to a public hearing process.[15] However, the negotiated prices are not the same as market-based prices. They are, rather, prices based on the cost of

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[14] Canadian interest in producer "netbacks" stems from the importance of the Canadian gas producing industry to its economy.

[15] If an applicant has negotiated its transportation service packages with shippers, and that no shipper objects to the proposed tariff and tolling method, then the NEB would approve the tariff. If however, objections emerge, then the NEB would evaluate each case individually.

service. For all negotiated prices, the pipeline company must provide the NEB with a tabulation of the agreed revenue requirements, the resulting tolls, an explanation of how the tolls were derived, and a description of issues that might have arisen and their resolution.[16]

For capacity expansion projects, the costs of new expansions can be averaged in with existing costs such that prices are set based on the overall costs of the system. And for new pipelines, applicants must show enough demand and plan to recover all costs from its customers.

The NEB has not set specific rules prohibiting the use of contracts with affiliates to demonstrate market support for a project. However, it requires the applicant to offer to all shippers the same opportunity to participate, and enter into contracts under the same terms and conditions of service, as it does affiliates.[17]

Relaxation of Regulation of Existing Pipelines: The Case of "Market-based" Rates

To this point we have reviewed the issue of competition from new pipelines, and regulatory policies designed to ensure that such competition is efficient. Theconsequences of revocation of coverage of an existing pipeline presents a different set of issues, however. This is largely because the existing pipeline investment is sunk and not generally capable of being redeployed to another use or market, and existing customers may not be adequately protected by long-term contract from the abuse of market power should there be no regulatory constraint imposed.

These issues have been addressed to some extent in North America, in decisions by regulators to consider more flexible, "market-based" rates for pipeline and electric power companies that can establish that they face substantial competition from alternative providers of service.

Traditional Pricing Policy

In the US, the FERC traditionally has required pipeline companies to establish maximum tariff rates that reflect the costs of providing service. This policy is termed "cost-of-service" rate regulation. Before the deregulation of the natural gas industry in the late 1980s, endusers and customers purchased a bundled commodity and transportation product andpaid prices that included the cost of gas with the cost of transporting it fromthe production area to the distribution area.

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[16] Guidelines for Negotiated Settlements of Traffic, Tolls, and Tariffs, National Energy Board, August 23, 1994.

[17] Reasons for Decision, Vector Pipeline Limited Partnership, NEB, March 1999, para. 260.

Beginning in 1985 with a series of orders, FERC began to encourage voluntary open-access policies on pipelines and eventually required the separation of commodity sale from gas transmission services.[18] Subsequently, the FERC set new rules for classifying costs that were used in pricing gas transmission.[19] Although the exact method of calculating prices had changed, FERC preserved the cost-of-service concept and required pipeline companies to set prices to recover their costs. The price for gas transmission comprised two components: a reservation charge and a usage charge. The reservation charge would recover the fixed costs (*e.g.* depreciation, return on investment, fixed operations and maintenance costs, and taxes) while the usage charge would recover the variable costs (*e.g.* fuel for compressors and variable maintenance costs) of gas transmission.

FERC's 1996 Policy for Qualifying Gas Pipelines for Market-based Rates

In early 1995, the FERC began to review policy recommendations from natural gas distributors, producers and marketers for pricing methodologies that deviated from the traditional cost-of-service method. On January 31, 1996, the FERC issued an order that set the criteria for evaluating market-based rate proposals for pipeline transmission and related services.[20] *The primary criteria for allowing the market to determine the gas transmission price is that the pipeline company must demonstrate that it does not have market power or that it cannot exercise its market power.* The FERC defines market power as the ability for a firm (or group of firms) to profitably maintain prices above competitive levels for a significant period of time.[21] The criteria for showing that a company does *not* have market power were drawn from the U.S. Department of Justice and Federal Trade Commission's Horizontal Merger Guidelines, employed for market power analysis in antitrust and merger

[18] FERC Orders 436, ("Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol" issued in October 18, 1985) instituted open-access, non-discriminatory transportation to permit downstream gas users such as local distribution companies and industrial customers to buy gas directly from merchants in the production area and to ship that gas via the interstate pipelines. FERC Order 636 (issues on April 8, 1992) required pipelines to separate their sales and transportation services and provide open access transportation service that is comparable in quality for all gas supplies whether purchased form the pipeline or elsewhere.

[19] FERC established the straight-fixed-variable methodology where all of the fixed costs associated with gas transmission was to be recovered by the reservation charge component of the price.FERC's primary goal was to maximise the benefits of wellhead decontrol by increasing competition among gas merchants, including pipelines. (FERC Order 636, April 8, 1992, p. 128.)

[20] A market-based rate is the price determined by supply and demand or is the price to which a buyer and a seller mutually agree..

[21] Policy Statement on Incentive Regulation, FERC Docket No.PL92-1-000, October 30, 1992, p. 21.

cases.[22] The FERC would allow companies that could establish that they lacked significant market power to charge "market-based rates" for gas transmission and related services. The FERC does so by reviewing each request for market-based rates on a case-by-case basis.

FERC's General Principle

FERC's framework for evaluating requests for market-based rates is based on how a company answers the principal question of whether it can *profitably* withhold or restrict services, and thereby raise prices, for a significant period in the relevant market. For the FERC to conclude that a seller could *not* restrict service and increase price over an extended period, the FERC must conclude either that the company lacks market power (because customers have sufficiently good alternatives) or that the company would mitigate its market power.

FERC's Analytical Methods for Evaluating Market Power in Gas Transmission

In evaluating a request for market-based rates, the FERC follows three principal steps: define the relevant markets, measure the company's (hereafter referred to as "the applicant") market share and market concentration, and evaluate entry and other factors.

Define the relevant markets

To define the relevant markets, the applicant must identify the specific products or services, and other suppliers of those products or services that provide good alternatives to the company's customers and thereby limit the company's ability to exercise market power. To qualify as a good alternative, other suppliers' product and services must be alternatives that *are available soon enough, have prices that are low enough, and have quality high enough to permit customers to substitute the alternative for the applicant's services*.[23] In addition, the alternatives must be available in sufficient quantity to make the applicant's hypothetical price increase unprofitable.

The appropriate market definition has two components: *a product market* and *a geographic market*. Typically, if an applicant can show that it does not have market power in narrowly defined markets, it will not have market power when the definitions were broadened. The FERC thus prefers that applicants define markets narrowly for the purpose of assessing market power. By specifying the relevant product and geographic market, an

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[22] These were the guidelines used by Department of Justice and the Federal Trade Commission to assess whether companies that result from mergers of firms operating in similar product markets but in different geographic locations would have market power.

[23] Statement of Policy and Request for Comments, 74 FERC 61,076, January 31, 1996.

applicant shows what alternatives its customers have if they attempt to avoid a price increase imposed by the applicant.

A product market includes the applicant's service and other services that are good alternatives. The applicant must show how each alternative service in the product market is an adequate substitute for the applicant's service in terms of *availability, price* and *quality*. Specifically, the applicant must evaluate and demonstrate to the FERC how well each alternative serves as an substitute for applicant's service by *the time period in which it is available, the price at which it competes with applicant's service, and the quality of alternative.*

- Timeliness of Alternatives

The definition of the product market may vary depending on the*time period* considered, therefore, an applicant must define the relevant time period associated with each product market. The U.S. antitrust authorities have generally used one year as the time period in which to test whether a product can become a substitute. However, one year is not usually appropriate for long-term gas transmission because the use of pipeline transmission is seasonal such that the demand level in the winter (and in some locations summers) is generally much higher than the demand in the spring and fall. In addition, long term contracts that customers use to secure capacity on competitors' pipelines cause that capacity to be *un*available for the term for the contract. Thus, good alternative capacity typically should be available simultaneously with the applicant's product. For example, if the applicant relies on the existence of capacity that is *not* immediately available because of long-term contracts, then the applicant must show that those capacities will be available within the defined relevant time period.[24] Specifically, the applicant's customers should be given the option to reduce service demand levels when alternative capacity becomes available.[25]

- Price of Alternatives

Applicants for market-based rates must also demonstrate that the price for the available alternative is low enough to effectively restrain the applicant from increasing prices. The FERC has used a rule-of-thumb price increase threshold of 10 percent. In other words, if the FERC believes that the applicant can sustain a price increase of 10 percent or more without

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[24] A customer sometimes can be tied to certain pipeline capacity even after the expiration of contract through its right of first refusal rules. Market-based Rates for Natural Gas Companies, FERC Staff, February 8, 1995, p. 29,

[25] Statement of Policy and Request for Comments, FERC, January 31, 1996, p. 24.

losing significant market share, then it is in a position to exercise market power to the detriment of the public interest.[26]

- Quality of Alternatives

A good alternative must provide service of a quality at least as high as that of the applicant's service.[27] To identify good alternatives, the applicant must first describe its own service, then identify all the available third party services that are comparable to it.[28] Generally, under an open access regime, all firm transmission services on interstate pipelines are operationally comparable. However, if an applicant wants to use interruptible service as an alternative to its firm transmission service, then the applicants must demonstrate that an adequate amount of capacity is available during peak periods. Only then would the quality of the interruptible transmission service be comparable to that of the applicant's firm transmission service.

A geographic market includes the applicant and the collection of alternative sellers of the applicant's product or service. Geographic market definition is particularly important in network industries because the structure and capabilities of the network to provide service may depend heavily on where a particular customer is located, particularly if there are network delivery constraints. For example, gas pipelines may transport gas from and to multiple producing and consuming regions. The FERC requires applicants for market-based rates to specify both their origin and destination markets for firm transmission services.

The FERC requires two steps in defining geographic market definitions. First, the applicant needs to identify those alternative sellers who offer service *between the same origin and destination markets*. Second, the applicant would identify those competitors that provide service *either out of the origin market or into the destination market.* The FERC is concerned that the applicant might have market power in the origin market if producers have few good alternatives to transport their product out of the origin area. Likewise for destination markets, pipelines might be able to exercise market power if downstream customers have only a few good transportation alternatives that reach their destination region.

- Transmission between Markets

As the first step in identifying geographic markets, the applicant needs to identify sellers that offer available transmission service over the same path. The FERC staff recognises that

[26] Statement of Policy and Request for Comments, FERC, January 31, 1996, p. 26.

[27] Market-based Rates for Natural Gas Companies, FERC Staff, February 8, 1995, p. 31.

[28] FERC Staff believes that with open access for gas transmission, all interstate pipelines provide operationally comparable firm transportation or transmission service.

in practice, parallel path competition is only likely to occur for either secondary markets (including interruptible transmission service) on the same facility or for transmission between well-functioning market centres.[29]

- Transmission at Origin and Destination Markets

A producer at the production or origin market would typically have alternative destination markets to which it could send gas. Similarly, a downstream supplier at a destination market would typically have a choice of producing areas in which to buy gas. Pipelines that provide such alternative service may offer an additional check on the market power of a transmission provider. To define a particular region as an origin market, the applicant must identify all other pipelines that compete with it to move gas out of that area. To demonstrate that these other pipelines are good alternatives, the applicant must show that either its producer is physically connected to these alternative pipelines, or its producer *can* connect to alternative pipelines cheaply enough to receive the same amount of net profit.[30]

The destination market for gas is where a local distribution company or end user receives gas. To define a destination market, the applicant must demonstrate that either its customers are physically connected to alternative gas transportation facilities that move gas into the area or that they can connect to the alternatives cheaply. For either approach, the applicant must demonstrate that the customer/shipper would pay no more with the alternative than with the use of the applicant's transmission service to deliver gas into the area. Applicants can also use liquefied petroleum gas (LPG) and liquefied natural gas (LNG) as alternatives if they can show that sufficient quantities of these fuels are available, and that their delivered price (including transportation costs) is not greater than the delivered gas price on the applicant's pipeline plus 10 percent.

Measure the applicant's market share and market concentration

Market power is defined as the ability of a pipeline to profitably maintain prices above competitive levels for a significant period of time.[31] While FERC has not adopted a mechanistic approach to assess market power, it has used a set of general criteria to evaluate the competitiveness of gas transmission services. An applicant might be able to exercise market power if its customers have only few good alternatives to the pipeline's service either over a specific path, or separately in the origin and destination markets.

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[29] Market-based Rates for Natural Gas Companies, FERC Staff, February 8, 1995, p. 35.

[30] FERC calls this net profit "netback", which is the delivered price of gas less the transportation costs paid by the producer.

[31] Market-based Rates for Natural Gas Companies, FERC Staff, February 8, 1995, p. 24.

A seller of pipeline service has two ways of exercising market power, either by acting alone or by acting together with other sellers, e.g. collusion.

- Acting Alone

Having a large market share is generally a necessary condition for the exercise of market power. Thus, the FERC requires an applicant for market-based rates to calculate its market share in all relevant origin and destination areas. A seller that has a small market share is unlikely to be able to exercise market power. A seller that has a large market share also might not be able to exercise market power if new entry into the market is easy. However, entry into the gas pipeline industry is generally *not* easy considering the cost of construction and the time for environmental analysis.

- Acting with Other Sellers

A second way in which a seller can exercise market power is to act together with other sellers to raise prices. To evaluate whether a seller can act together with others to exercise market power, the FERC typically examines the market's concentration. The FERC has traditionally measured market concentration by the Herfindahl-Hirschman Index (HHI). The HHI is defined as the sum of the squares of each competitor's market share. For example, if a market has only one seller, the HHI would be 100% squared, or (100.0)^2 = 10000. If a market has two sellers, one with 20 percent market share and the other with 80 percent market share, then the HHI would be (20)^2 + (80)^2 = 6,800.

The FERC has *not* adopted a rigid threshold below which an applicant would automatically qualify for market-based rates, or above which an applicant would be excluded from market-based rates. Instead, the FERC uses an HHI of 1800 as an indicator of the level of scrutiny to be given to the applicant. If the HHI is above 1800, the FERC will closely scrutinise the applicant because the index shows that the market is concentrated and that the applicant may have significant market power. An HHI below 1800 would call for less scrutiny of the applicant's potential to exercise significant market power.[32] Generally, a high HHI indicates that sellers may be able to exercise market power and a low HHI indicates that customers have sufficiently diverse sources of supply in the market such that no one firm or group of firms acting together could profitably raise market price.

The FERC requires applicants for market-based rates to submit calculations of HHIs for the relevant markets. HHIs must be computed for each origin market and each destination market. If an applicant wishes to use broader market definitions than each distinct origin and destination market, then the applicant must calculate HHIs for those markets accordingly. To

[32] See Statement of Policy and Request for Comments, FERC, January 31, 1996, p. 36. Also, see Market-based Rates for Natural Gas Companies, FERC Staff, February 8, 1995, p. 41. The FERC staff believes that a relatively strict initial screen that imposes an HHI threshold of 1800 is appropriate. This number indicates that there are four to five good alternatives to the applicant's service in each market.

calculate market shares and HHIs, the FERC requires applicants to include only the amount of sales or capacity associated with good alternatives in the market definition.

Evaluate Entry and Other Competitive Factors

The FERC also considers other competitive factors in evaluating market power. Even if the applicant's market share were large in a concentrated market, there still might be special conditions from which the FERC might conclude that the applicant could not exercise market power. One example would be ease of entry. If entry into the market were so easy that sellers can profit by quickly taking customers away from the applicant, then the applicant may not have market power. Another example is buyer power. If the applicant can demonstrate that its buyers have the power to negotiate reasonable prices even in a concentrated market because of the buyer's size, or knowledge and sophistication in purchasing, then again, the applicant may not have market power.

Market Power Mitigation

For applicants found to have market power, they can facilitate changes to mitigate the effects of market power and still be granted market-based rates. For example, an applicant might suggest that the FERC permit market-based rates for a pipeline segment, such as for a new lateral. The applicant can propose to refrain voluntarily from allocating costs attributable to the lateral to its other cost-based services. The applicant might also voluntarily allow other entities to interconnect with its facilities to protect against withholding capacity by under-sizing or over-pricing the new lateral.

In Appendix 2 to this report, we include a description of the analysis performed in relation to an application for market-based rates files by the Koch Pipeline Company.

FERC's Policy and Experience on Market-based Prices for Electric Generation

The electricity market in the U.S. has been moving quickly toward increased competition, with regional independent power pools developing and power marketers playing a significant role. Power marketers are brokers for power transactions. They act as agents that bring together buyers and sellers of electricity, and they do not take title to and resell the power themselves. Since most power marketers do not own or control generation or transmission facilities that could give them market power in their respective markets, they are permitted to charge market-based rates.

Commencing in the latter half of 1990s FERC has been certifying companies that own electric generation assets to sell power at market prices. FERC has a slightly different set of guidelines for applying for market-based rates for wholesale electricity compared to those for gas pipelines. FERC requires wholesale generation companies that apply for market-based rates to demonstrate that the company does not have market dominance in the relevant markets. A market share of more than 20 percent defines market dominance. Even though the 20 percent market share is not a bright line that exactly delineates between companies with and without market dominance, FERC uses this 20 percent as a guideline in reviewing companies' applications for market-based rates.

FERC's Requirements for Granting Market-based Rates to Electric Generators

In electric generators' application for market-based rates, the FERC requires applicants to answer two questions. The first question is whether an applicant has the ability to exercise market power by withholding its capacity and increasing its electricity prices. Under this guideline, the applicant must demonstrate that it does *not* have dominant control over generation assets, dominant control over transmission assets, or control over barriers to entry.

The second question is whether the applicant can unduly discriminate in price or in terms and conditions. This question is a particular concern when the generation owner has affiliates with whom it trades in the market. The general concern with affiliate transactions is that a public utility with captive customers may sell power to an unregulated affiliate at a price below the utility's cost. The result is that captive customers would cross-subsidise the shareholders of the unregulated affiliate. Cross subsidisation can also arise if an unregulated company sells power to a utility with captive customers at an above-market price. This causes the captive customers to cross-subsidise the shareholders of the unregulated affiliate. FERC evaluates applicants based on these issues.

Even though FERC uses a 20 percent market share as a guideline for market dominance, FERC can still allow a company to charge market-based rates if mitigation plans are sufficient to eliminate its market power.[33] In fact, the FERC did so in a case we describe below.

FERC's Analytical Method for Evaluating Market Power in Electric Generation

The FERC's analysis of whether a market-based rate applicant has any concentration-induced generation market power includes three steps: (1) define the relevant markets; (2) measure the market shares and concentration measures; and (3) evaluate other relevant factors.

Similar to the gas transmission guidelines, FERC considers two types of relevant markets: a product market and a geographic market. The *product market* includes electricity *products or services* that are sufficiently good substitutes for one another such that competition between them will place an upper constraint on the prices that the applicant can charge. The *geographic market* includes all supply *locations* that are sufficiently good substitutes for one another such that competition between them will also place an upper constraint on the price that the applicant can charge for the product under consideration.

[33] Louisville Gas and Electric Company, 62 FERC ¶ 61,016 (1993).

Definition of Product Market for Electric Generation

The FERC traditionally has defined relevant generation products on the basis of short-term versus long-term transactions and firm versus non-firm energy services. Three products are typically identified as relevant products: (1) non-firm energy, (2) short-term capacity, and (3) long-term capacity. In practice, FERC has noted that the potential exercise of market power in long-term capacity markets is largely a function of entry conditions in the relevant market. In several market-based rate proceedings, utilities and power marketing companies have used - and the FERC has accepted - "installed capacity" and "uncommitted capacity" analyses to support their market-based rate requests.[34] These products were meant to measure short-term non-firm energy and short-term capacity.

Definition of Geographic Market for Electric Generation

Historically, the FERC has defined geographic markets using a "hub-and-spoke" approach that defines the relevant geographic market based not on the cost of transmission but simply by the number of control area "wheels" assumed possible. These "wheels" are the so-called first-tier and second-tier interconnections. Control areas are traditionally the geographic areas that cover customers served by a utility. The first-tier interconnections comprise utilities that directly interconnect with the applicant through physical transmission interconnections. The second-tier interconnections comprise utilities that directly interconnect with the first-tier utilities. The geographic market for any one utility consists of all suppliers in that utility's control area plus all those in first-tier interconnects.

Southern Company's Application for Market-based Rates[35]

In 1995, Southern Energy Marketing, Inc (or Southern Energy) filed an application with FERC to sell power at market-based rates. Southern Energy has an affiliate utility that owns electric generation and transmission assets and at that time, Southern Energy planned to become a power marketer. If an affiliate of a transmission-owning public utility requests for market-based rates, the FERC requires the applicant to demonstrate that it does not have, or has mitigated any, transmission market power. To do so, the transmission-owning entity must file with the FERC an open-access transmission tariff for the provision of comparable services. Southern filed its open-access tariff and had gained FERC's acceptance.

Southern Energy's market share - based on installed generation capacity - exceeded the 20 percent threshold established by the FERC and reached as high as 26%.[36] However,

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[34] *Entergy*, 58 FERC ¶ 61,234 (1992) and *Louisville Gas and Electric Company*, 62 FERC ¶ 61,016 (1993).

[35] Order Accepting Market-based rates (as modified) for Southern, Issued September 29, 1995, The request was filed as Docket No. ER95-976-000 (72 FERC ¶61,324) on April 28, 1995.

Southern Energy argued that the FERC had not adopted its 20 percent market share rule as an absolute bright line test, and Southern Energy recommended that measures of uncommitted capacity would be more relevant than installed capacity for market power analysis. Uncommitted capacity measures the capacity available for sales of more than a year's duration, which is of greater concern than current market share if market power is defined as the ability to sustain sales above market prices. Southern Energy's market shares in the relevant markets based on uncommitted capacity are well below 20 percent.

The FERC agreed that the 20 percent is not a bright line test and that Southern Energy's market share based on installed capacity exceeded only *slightly* above 20 percent. The FERC agreed to consider uncommitted capacity of which Southern Energy's share is well below 20 percent. Thus, the FERC decided that Southern Energy met its generation market power requirements.

Another signification consideration in Southern Energy's case was its potential for affiliate abuse. Affiliate abuse in this context is the lack of arms-length transaction between a power marketer and its regulated affiliates. The FERC required that Southern Energy's affiliated operating companies not sell goods or services to Southern Energy, the power marketer, at a price below the operating companies' cost. This would prevent any cross-subsidisation from captive customers to shareholders of the unregulated affiliate.

FERC approved Southern Energy's market-base rate application on the grounds that Southern had demonstrated it does not have market dominance in electric generation and electric transmission, and creates no barriers for entry.

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[36] Southern asserted that the 20 percent figure was Public Service Company of Indiana's proposal for its hearing and did not represent an independent determination by the FERC as to the maximum permissible market share. Southern Energy also noted that the Department of Justice Merger Guidelines use a 35 percent market share as a threshold for determining whether a party is a "leading firm" for purposes of market dominance.

Economic Literature on Role of Long-term Contracts as Protection Against Post-investment Market Abuse and Research on Competition in Network Markets

Long-term Contracts and Post-Investment Market Power Abuses

Traditional microeconomic theory is based on perfect information about prices and opportunities. However, real markets are burdened with asset dependency, sunk costs, and moral hazard. Contracts are often used to minimise the inefficiencies and opportunistic behaviours caused by these burdens. But when negotiating contracts, parties that have lower levels of bargaining power or market power than their counterparts may need help from regulators especially when contracts are imperfect and market conditions can change after contracts have been signed.

Transactions Cost and the Role of Contracts

In a world where there is imperfect information and where investors make investment decisions sequentially, opportunistic buyers or sellers may exploit their stronger bargaining power by delaying payment, asking for price or quantity renegotiation, or breaching the agreement altogether.[37] Contracts can minimise these opportunistic behaviours by establishing rules and criteria for the duration of the arrangements. Theoretically, complete contracts can stipulate all responsibilities and rights of every contract party and specify every conceivable contingency that could arise in the future, including a breach of contract. However, even if a court of law oversees contract enforcement, complete contracts are too costly to write because it is too difficult to foresee all plausible contingencies, to evaluate and calculate measures of performance in every such contingency and to guarantee that information is made available to every party.

Conversely, incomplete contracts may be viable tools for guiding complex transactions. These contracts would account for the most probable contingencies and incorporate some flexibility, such as price escalation or review clauses. These contracts are also easier to write and to enforce than complete contracts. However, the drawback of an incomplete contract is its broad language that can leave open the opportunity for exploitative behaviours.[38] In other words, there is a tradeoff between the *ex ante* costs of crafting more complete contracts and

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[37] Besanko, Dranove and Shanley., *The Economics of Strategy*, New York: John Wiley & Sons, 1996, p. 103.

[38] Specifically, tactics contractors might exploit in attempting to affect the distribution of the gains from trade include taking advantage of ambiguous terms in the contract, suing for frivolous deviations or falsely claiming dissatisfaction, withholding relevant information, failing to cooperate in the other party's performance, and failing to mitigate damages in the case of breach. Crocker & Masten, "Pretia Ex Machina? Prices and Process in Long-Term Contracts," 34 *Journal of Law & Economics* (4/91), p. 72.

the *ex post* costs of potentially harmful effects and inefficiencies from less comprehensive contracts.[39]

Relationship-specific Assets and the Threat of Hold-up

One type of transaction cost is the cost associated with *relationship-specific assets*. These assets are investments made in support of a particular transaction, which have a higher value in their intended use than in their second best use.[40] These relationship-specific assets cannot be redeployed to a different use without sacrificing their productivity or incurring significant costs. Owners of these assets might have made specific investments in physical equipment, choice of plant site, and development of human capital.

An investor of relationship-specific asset usually becomes dependent on a particular contract (or transaction) that is not costless to adjust. The dependency stems from the investor's irreversible investment or *sunk costs* that weakens his *ex post* bargaining position.[41] Even if competing alternatives exist before investments were made, the post-investment environment may leave the investor with few alternatives. The lack of alternatives then establishes a new price that would leave the investor worse off than before, but a price that he would be willing to pay just so that he does not have to bear the costs of switching or sinking more fixed costs.

The exploitation of a stronger bargaining position after a contract counterparty has made his relationship-specific investments is a *hold-up*. This hold-up problem can raise the costs of exchange even before the transaction because the possibility of a hold-up creates distrust between contract counterparties.[42] In fact, parties that invest in relationship-specific assets may even invest in extraneous facilities or resources just to increase their next best alternative in case its counterparty acts opportunistically.[43]

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[39] Crocker & Reynolds, "The Efficiency of Incomplete Contracts: An Empirical Analysis of Air Force Engine Procurement," 24 *Rand Journal of Economics* (Spring '93), p. 126.

[40] Crocker & Masten, April 1991, p. 69.

[41] Spulber, *Regulation and Markets*, Cambridge: MIT, 1989. The concept of sunk costs is paramount to regulatory economics. Future decisions cannot be based on these costs, since future actions cannot recover these expenditures. The party that has not made irreversible investments has an incentive to call for renegotiation of contractual agreements made earlier. The other party anticipates this threat, and has an incentive to invest in reliance suboptimally.

[42] Crocker and Reynolds, 1993.

[43] Besenko, Dranove and Shanley, 1996, p. 127.

Most-Favoured-Nation Clause as a Protection Against Ex Post Opportunism

Since basic contracts cannot adequately mitigate all opportunistic behaviour, different forms of contracts have developed with self-enforcing capabilities. For example, most-favoured-nation clauses (MFNs), take-or-pay provisions,[44] price-adjustment targets or mechanisms, fixed-price incentives and price caps are commonly used to limit abusive behaviour.[45] Here, we focus on one of these options: the most-favoured-nation clause.

MFN clauses require a buyer or seller to treat all trading partners equally in pricing decisions even when facilitating price adjustments.[46] The concept came from international trade practices where countries promise to give goods from a particular country the most favourable treatment that is given to any other trading partner. Crocker & Lyon (1994) showed that MFNs can facilitate efficient price adjustment in long-term relationships and Hubbard & Weiner (1991) noted that MFN clauses could mitigate the *ex post* opportunistic behaviours. They mentioned that the party fearful of being at a disadvantage in contract negotiations could protect themselves by specifying that future bargained prices or other outcomes will apply to them as well.[47]

In Appendix 1 to this report, we summarise the principal articles cited above, as well as some of the experimental research that was done in the early 1990's simulating the behaviour of gas pipeline markets, in which holders of capacity ("cotenants") were permitted to freely trade that capacity. Such market models were considered as a substitute for traditional regulation. These studies also attempted to develop normative standards for determining how many players (pipelines or holders of pipeline capacity in a trading market) were necessary to ensure competitive outcomes. Our impression is that there are serious limitations to these studies that make them difficult to rely on in interpreting real-world gas markets. However, normative behaviour models of gas and electricity markets that attempt to simulate oligopolistic behaviour are growing in use in competition law and regulatory matters. For example, such models are now increasingly used in North America to analyse the competitive effects of mergers involving electricity and gas companies.

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[44] Take-or-pay provisions prevent reverse abuse by customers by requiring them to pay for a contractually specified minimum quantity of output, even if the delivery is not taken. See Masten & Crocker, "Efficient Adaptation in Long-Term Contracts: Take-or-Pay Provisions for Natural Gas," 75 *American Economic Review* (12/85), p. 1083.

[45] For a detailed range of contractual options see Crocker & Reynolds, *supra* note 3, p. 130.

[46] Crocker & Lyon, "What Do 'Facilitating Practices' Facilitate? An Empirical Investigation of Most-Favored-Nation Clauses in Natural Gas Contracts," 37 *The Journal of Law & Economics* (10/94), p. 297.

[47] Hubbard & Weiner, "Efficient Contracting and Market Power: Evidence from the U.S. Natural Gas Industry," 34 *The Journal of Law & Economics*, April, 1991, p. 28.

APPENDIX 1: Summaries of Selected Academic Literature

1. Crocker & Masten, "Pretia Ex Machina? Prices and Process in Long-Term Contracts," ***Journal of Law and Economics,*** **1991.**

The motives for writing contracts often reflect desire to protect against the hazards of one party taking advantage of the changes in market conditions arising after the initial agreement, and engaging the other party in costly disputes, renegotiations, or even breaching the contract. However, contracts are imperfect tools for controlling opportunistic behaviours. First, not all contingencies can be efficiently stipulated in advance. Second, contract law and governing authorities are rarely capable of enforcing contractual intentions in fully efficient manner. Third, rigid contracts do not allow for flexible adjustments to changing market conditions. Finally, contractors maintain the capability to use various tactics—such as delaying, withholding information, or suing for trivial deviations from contract terms—to induce outcomes contrary to those originally desired. As such, contracts are used less for controlling opportunism than for establishing procedures and threats from which parties can redetermine or renegotiate terms in the future.

2. Crocker & Lyon, "What Do 'Facilitating Practices' Facilitate? An Empirical Investigation of Most-Favoured-Nation Clauses in Natural Gas Contracts," ***JLE,*** **1994.**

Long-term contracts often include most-favored-nation clauses (MFNs), which are non-discrimination guarantees that obligate a buyer or seller to treat all trading partners symmetrically in pricing decisions. Such guarantees may stipulate that the contract price be equal to the lowest price charged in a particular region, which ensures that the buyer benefits from any price reductions that sellers might concede to other customers. Since a buyer will guarantee the lowest prevailing price, he will not be afraid to invest in relationship-specific assets. The authors hypothesised that if MFNs are used to facilitate collusion, then beyond some threshold number of buyers, their adoption should be negatively related to the number of buyers. If MFNs are used to increase efficiency, their use should be positively related to number of buyers. They conducted econometric analyses of the natural gas industry and found that MFN non-discriminatory guarantees are more likely to be used to craft efficient contracts to facilitate price flexibility than to collude.

3. Crocker & Masten, "Mitigating Contractual Hazards: Unilateral Options and Contract Length," ***RAND Journal of Economics,*** **1988.**

The optimal contract length reflects a trade-off between the costs of negotiating the terms of a trade and the hazards of being bound to an inflexible agreement for an extended period. The presence of regulation can create distortions in contract terms for the supply of natural gas. For example, regulatory interference is likely to raise the potential liabilities of contractual exchange and thereby lead to shorter-than-optimal contracts. In other words, the expectation of regulatory change, whether toward more or less regulation, leads to shorter contracts, as companies desire agreements that will not tie them to a particular set of rules in the face of changing regulatory landscape.

4. **Hubbard & Weiner, "Efficient Contracting and Market Power: Evidence from the U.S. Natural Gas Industry," *JLE*, 1991.**

In the natural gas industry, contract prices tend to go through frequent and costly renegotiations. The relationship between a producer and a pipeline is characterised by both having relationship-specific assets. Once the initial gas well development costs are sunk, a pipeline faces the temptation to appropriate some of the economic rents from production unless the producer has an alternative means of sale. The pipeline itself is a form of specific capital. Since it is best operated near full capacity, a long-term contract guaranteeing supplies is in the pipeline's interest as well as the producer's. The authors used the gas industry to consider the relative effects of transaction-specific and market-power considerations on outcomes of contract negotiations. They hypothesised that long-term contracting is a means to approximate pricing efficiency and that MFN clause can mitigate the *ex post* opportunistic behaviours (e.g. by the pipeline to renegotiate for lower prices). On the flip side, however, the seller can use MFN clauses to raise contract prices to the level of the highest price paid by the pipeline on any new contracts in the field. The empirical analysis shows that buyers (the pipelines) have some monopsony power to influence initial contract price. Transaction-specific and firm-specific variables such as buyers' and sellers' market shares are also important in setting the initial price. However, MFN clauses mitigate buyers' advantage to some degree, by providing the sellers (well owners) to take advantage of the highest price in the market area.

5. **Besanko, Dranove, and Shanley, <u>The Economics of Strategy</u>, Chapter 3, 1996.**

Contracts are necessary because all but the simplest transactions will expose a party to the risk of opportunistic behavior by its trading partner. However, complete contracts are rigorous, and incomplete contracting arises due to (1) bounded rationality, (2) difficulties in specifying or measuring performance, and (3) asymmetric information. Opportunistic behavior is particularly rampant when a transaction involves relationship-specific assets. When this happens, a party cannot costlessly switch trading partners, as it has invested in (or relied on) physical or human capital tailored to the original transaction. This situation gives rise to a quasi-rent (*ex post* economic rent) from which the counterpart can benefit by forcing contract renegotiation. This is also referred to as the "holdup" problem associated with relationship-specific investments. Hold-up problems raise the costs of exchange by producing distrust, causes lost opportunities or insufficient investment in relationship-specific assets, and engenders costly negotiation or legal action.

6. **Crocker & Reynolds, "The Efficiency of Incomplete Contracts: An Empirical Analysis of Air Force Engine Procurement," *RAND Journal of Economics*, 1993.**

While complete contracts can mitigate *ex post* opportunism associated with insufficiently exhaustive arrangements, this happens at the *ex ante* expense of designing such complex agreements. The degree of contractual completeness, therefore, depends on parties minimizing the sum of these costs. Market conditions, such as technological uncertainty or the potential for hold-up problems in a single source environment, can exacerbate the potential for *ex post* inefficiencies and opportunistic abuse. Contracts can fall anywhere into a range set by firm-fixed price (fully rigid) and fixed-price incentives (allowing for *ex post* negotiations regarding price, profit, and cost). Any policy attempting to impose homogeneity in contract design either across contractors or over time would be misguided.

7. **Maasten & Crocker, "Efficient Adaptation in Long-Term Contracts: Take-or-Pay Provisions for Natural Gas," *The American Economic Review*, 1985.**

A principal limitation of long-term contracting is its inflexibility in the face of fluctuations in the supply and demand. "Take-or-pay" provisions are flexibility-enhancing clauses that require purchasers to pay for a contractually specified minimum quantity of output, even if delivery is not taken. The purchasers have the advantage of being able to adapt to a changed market environment and have an opportunity to breach from the contract if the benefit of doing so exceeds the cost of the breach.

8. **Rassenti, Stephen, Stanley Reynolds, and Vernon Smith, "Cotenancy and Competition in an Experimental Auction Market for Natural Gas Pipeline Networks," *Economic Theory*, 1994.**

The authors conducted a laboratory simulation of "smart" computer-assisted auction mechanism for the allocation of resources within a network of commodity flows. The primary purpose of the series of the experiments is to investigate and measure the effect of pipeline cotenancy on auction outcomes. By "cotenancy", the authors mean any sharing of pipeline capacity rights among more than one agent. Cotenancy will arise whenever two or more firms undertake a joint investment venture to construct a new pipeline. It may also arise when a pipeline user acquires certification rights from the original owner. They investigated cotenancy, including the rules governing cotenancy agreements because this appears to be a promising vehicle by which the government might institute a competitive self-regulating property right system to replace rate-of-return regulation of a monopoly owned capital facility. Their objective was to explore the possibility of using the competitively ruled cotenancy agreement in place of direct regulation for natural monopoly producer situations. They used a computerised dispatch system that combined the information advantages of decentralized ownership with the coordination advantages of central control. The design of the model can be thought of as a uniform-price double auction, where gas producers and gas transporters make offers indicating their willingness to supply and move gas and buyers make bids indicating their willingness to pay for delivered gas. The results of the experiments show that a centralised dispatch centre can elicit high levels of performance in a marketplace with a relatively small number of participants.

APPENDIX 2: Koch's Request for Market-based Rates for Gas Transmission as an Example of Current Practice in the U.S.

In June of 1995,[48] Koch had filed its proposal for market-based rates and associated market power analysis at the FERC. Koch's application was the first gas transmission market-base rate application at FERC.[49] This application and the ensuing FERC decision showed that the issue of market-based rates continues to be quite contentious in the U.S. and that in practice, it is complicated and difficult to conduct a comprehensive market power analysis for gas transmission that would satisfy FERC's criteria for market-based rates.

A FERC Administrative Law Judge (ALJ) was assigned to decide the Koch application and on August 25, 1997, the ALJ issued his initial decision and found that Koch lacked market power as defined in the FERC policy and thus warranted market-based rates. However, following his decision, market participants and FERC Staff intervened and argued against the ALJ's decision. After considering the arguments of the intervening parties, on October 2, 1998, the FERC issued a new order that reversed theALJ's initial decision and decided that Koch had *not* shown that it lacks market power. The FERC based its decision on the following reasons:

Koch did not properly define its product and geographic markets

For product market definition, Koch defined its product as both its firm and interruptible transportation services (which it regarded as equivalent). For geographic market definition, Koch defined its geographic market as the area covered by its entire system. This area included 9,000 miles of pipeline located in five southern states of the United States.[50]

- Product Market

Koch did not demonstrate that the quality of its interruptible transportation service was comparable to that of its firm transportation service as required by the FERC. To do so, Koch would have had to present evidence ofunsubscribed capacity that exists on its system either

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[48] Koch filed its request at the FERC after the FERC issued a request for comments on methods of ratemaking that could be alternatives to traditional cost-of-serviceratemaking in February of 1995.

[49] Prior to Koch's application, many companies have requested for market-based rates for gas storage or for a specific segment of a pipeline infrastructure.

[50] Koch claimed that the path, origin and destination markets described in the FERC policy statement were not applicable in its case because Koch is not a long-line pipeline, but a feeder pipeline in a production area. It stated that its system functions as a grid with receipt and delivery points throughout. See Order Reversing Initial Decision, Docket No.RP95-362-000, 61 FERC 61,013, October 2, 1998, p. 8.

during peak periods or all year round.[51] The FERC disapproved Koch's product definition but continued to evaluate its case since Koch used the total installed capacity (as opposed to try to quantify available firm and interruptible capacities) in its market power analysis as show later.

- Geographic Market

Koch did not identify sellers or a collection of sellers from whom customers could purchase service. Effectively, Koch claimed that a customer in one part of its system could use an alternative in any other part of its system. But Koch also stated that price differentials exist between specific points on its system. Thus the FERC believed that customers' access could be limited by these price differentials. In addition, Koch's system is divided into divisions that have different prices, availability and costs.

Koch did not identify the appropriate alternatives within the product and geographic markets

Koch concentrated its analysis on pipelines located near its receipt and delivery points[52] and identified 1,588 of these points that formed the relevant markets. Koch considered that the pipelines located within a five-mile radius of these receipt and delivery points provided good alternatives whether or not Koch's customers were connected to those pipelines. Koch did not include the cost that customers would have to pay to connect to the unconnected pipelines and also did not determine whether connections would be economical. Koch in its application simply assumed that it *would* be economical to connect all of the unconnected pipelines and counted them as good alternatives.

Koch estimated the capacity available on the other pipelines by calculating their installed capacity. It claimed that it could not determine the amount of unsubscribed or available capacity because either there were too many unknown factors or the information was not publicly available. However, the FERC places the burden of proof on Koch and emphasised that only unused or available firm and interruptible transportation capacity on other pipelines constituted good alternatives to Koch's transportation services.

Koch argued that it could not sustain a price increase of more than 10 percent because it had to give discounts on its transmission prices. Koch also argued that any price increase in response to the weather was transitory and that the significant period for sustaining a price increase is one year. The FERC rejected these arguments by showing that Koch had

[51] Recall that FERC's policy provided that applicants wishing to show that interruptible transportation services are good alternatives to the applicant's firm services should demonstrate that an adequate amount of capacity is unsubscribed during peak periods so that the quality of the interruptible transportation service is comparable to that of the applicant's firm transportation service.

[52] Koch refers to these receipt and delivery points as station location numbers (SLNs).

maintained its prices above its cost-based tariff on several paths for several months in the winter. Since demand for gas is seasonal on many pipelines, with the demand at the winter peak often many times greater than during the summer months, a pipeline will be more likely to be able to exercise market power in peak winter periods than during the off-peak period. Thus, FERC found that Koch did not prove that it could not raise prices above 10 percent.

Lastly Koch did not show that its alternatives had comparable quality of service since it did not identify any of the owners of the unconnected pipelines and did not demonstrate that interruptible transmission is comparable to firm transmission service.

Koch did not evaluate market share and market concentration measures appropriately

Koch analysed its market share and market concentration based on the assumption that the unconnected pipelines were good alternatives, and Koch ascribed market shares to those pipelines based on their individual installed capacities. Koch did not show that capacity was available on those pipelines, that it was economical to connect to those pipelines, or that comparable service on those pipelines was available at prices comparable to Koch's.

To determine market concentration, Koch did not present in its application the HHIs for each of the 1,588 receipt and delivery points.[53] Instead, Koch calculated average HHIs over various markets such as capacity allocation areas, shippers other than pipelines and local distribution companies, pipelines, and large volume receipt and delivery points.[54] Some of these narrow markets had HHIs greater than FERC's threshold of 1800. When aggregated over Koch's entire system, the resulting HHI was less than 1800. However, the FERC requires HHIs to be calculated for each path and each origin and destination markets, and Koch did not do this.

Based on these reasons, the FERC rejected Koch's application for market-based rates.

[53] Koch claimed that the HHI calculations for each delivery and receipt point was incongruous with the actual operation of its network.

[54] The calculated HHI for individual capacity allocation areas and shippers were over 1800 for half or more. The calculated HHIs for pipelines (both individually and aggregated), for groups of large industrials, for large power plants and for large receipt points were less than 1800. See Order Reversing Initial Decision, Docket No. RP95-362-000, 61 FERC 61,013, October 2, 1998, p. 8.