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Tenneco Atlantic Pipeline Company, Tennessee Gas Pipeline Company (ERA Docket No. 77-010-LNG.), December 18, 1978.

Importation of Liquefied Natural Gas from Algeria.

[Opinion and Order]

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Glossary of Abbreviations

ALJ	Administrative Law Judge
Applicants	TAPCO and TGP
Bcf	Billion cubic feet
BLS	Bureau of labor Statistics
Btu	British thermal unit
the Commission	Federal Power Commission or Federal Energy Regulatory Commission
the Contract	the Supply Contract between Tenneco LNG and Sonatrach for the purchase of LNG
DEIS	Draft Environmental Impact Statement
DOE	Department of Energy
Gas Ships	Gas Ships, Inc.
ERA	Economic Regulatory Administration
FEIS	Final Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
FUA	the Power Plant and Industrial Fuel Use Act of 1978
I.D. or Initial Decision	the Initial Decision of Administrative Law Judge Litt
LNG	Liquefied natural Gas
Lorneterm	Lorneterm LNG Ltd.
Mcf	Thousand cubic feet
MMBtu	Million British thermal units
NEB	Canadian National Energy Board
NEPA	National Environmental Policy Act of 1969
NGA	Natural Gas Act
NGPA	Natural Gas Policy Act of 1978
OPEC	Organization of Petroleum Exporting Countries
PGAC	Purchase Gas Adjustment Clause
SNG	Synthetic natural gas
Sonatrach	Societe Nationale pour la Recherche, la Production, le

Transport, la Transformation et la Commercialisation des Hydrocarbures (Algerian National Oil & Gas Company)

Staff — Staff of the Federal Power Commission or Federal Energy Regulatory Commission

SVI — Shipping Ventures Inc.

TAPCO — Tenneco Atlantic Pipeline Company

TCF — Trillion cubic feet

Tenneco — Tenneco, Inc.

Tenneco LNG — Tenneco LNG Inc.

TGP — Tennessee Gas Pipeline Company

TransCanada — TransCanada Pipelines (New Brunswick) Limited

WPI-AC — U.S. Bureau of Labor Statistics, Wholesale Price Index--All Commodities

A. Project Description

Tenneco Atlantic Pipeline Company (TAPCO), a wholly owned subsidiary of Tenneco, Inc. (Tenneco), seeks authority under Section 3 of the Natural Gas Act to import at the U.S.A.-Canadian border approximately 1.0 billion cubic feet per day (Bcf/d) of regasified Algerian liquefied natural gas (LNG). TAPCO proposes to import the LNG for a period of 20 years commencing in late 1981, with full quantities scheduled for delivery in 1983.

Tenneco LNG Inc. (Tenneco LNG), a TAPCO affiliate, proposes to purchase LNG from Societe Nationale Pour la Recherche, la Production, le Transport, la Transformation, et la Commercialisation des Hydrocarbures (Sonatrach), the Algerian national oil and gas company. The base purchase price stated in the LNG Sales Contract dated October 4, 1976, between Tenneco LNG and Sonatrach is $1.30 per million British thermal units (MMBtu) as of July 1, 1975, subject to semiannual escalation based on the New York Harbor prices of No. 2 and No. 6 fuel oils.

The LNG would be transported in eight cryogenic marine tankers, each with a design capacity of 125,000 to 133,000 cubic meters of LNG. Four of the ships would be provided by Sonatrach and four would be provided by Tenneco LNG. The applicants propose to construct the four Tenneco vessels at the Newport News Shipyards, a wholly-owned subsidiary of Tenneco, Inc. Each of the four Tenneco vessels would be owned through general partnerships, with Tenneco holding 50 percent of each ship through four Tenneco subsidiaries, Shipping Ventures Inc., I-IV. The remaining 50 percent equity in each ship would be held by persons or entities not affiliated with Tenneco. Each SVI would then bareboat charter the four vessels to another Tenneco subsidiary, Gas Ships, Inc. (Gas Ships). Gas Ships in turn will enter into four Energy Transportation Agreements with another Tenneco subsidiary, Tenneco LNG.

The LNG would be transported to an import terminal and regasification plant at a site located on the Bay of Fundy near St. John, New Brunswick, Canada. The terminal and regasification facility would be owned and operated by Lorneterm LNG Ltd. (Lorneterm), another Tenneco subsidiary. A 750-acre area has been selected for the construction of the terminal and attendant facilities. The terminal itself would consist of tanker berths, 2,400,000 barrels of LNG storage capacity, a vaporization system and support facilities. Spare equipment would allow the plant to operate 365 days a year at a design capacity of 1,300 MMcf/day. The regasified LNG would be transported 66 miles to the U.S.A.-Canadian border in a 36-inch pipeline to be constructed and operated by TransCanada Pipelines (New Brunswick) Limited (TransCanada).

Under TAPCO's proposal the regasified LNG would enter the United States at the U.S.A.-Canadian border near Calais, Maine. TAPCO proposes to construct and operate 508 miles of 36-inch and 30-inch pipeline within the United States for delivery and sale of the regasified LNG to the Tennessee Gas Pipeline Co. (TGP), a subsidiary of Tenneco. The gas would be delivered to TGP at three points in the United States, near Albany, New York, Concord, New Hampshire, and Milford, Pennsylvania, where it would be distributed directly and by displacement throughout TGP's 22-state service area.

TAPCO estimates a delivered cost of $3.97 in 1983 dollars1/ per MMBtu at the Canadian border. Charges to be incurred in transporting the gas from the Canadian border to the U.S.A. delivery points are anticipated to be 47 cents per MMBtu (or 54 cents per Mcf) in 1983.

Sonatrach will invest approximately $2.3 billion (in 1975 dollars) in processing, liquefaction and other land based facilities in Algeria. Sonatrach expects its four ships to be delivered between 1981 and 1983, at a cost of about $600 million in 1976 dollars. TAPCO's four vessels are estimated to cost a total of $803 million at time of delivery and would be built in Tenneco's Newport News Shipbuilding, Inc., shipyards. TAPCO estimates the total construction cost of the LNG receiving terminal (to be in operation in 1981) at $636 million in 1981 dollars. TransCanada's pipeline is estimated to cost about $69 million in 1981. The total cost of the U.S.A. segment of the TAPCO pipeline is estimated at $732 million upon completion in 1981.

B. Procedural History

1. Prior Proceedings

On December 20, 1976, TAPCO filed an application with the Federal Power Commission (FPC) (FPC Docket No. CP 77-101) pursuant to Section 3 of the Natural Gas Act (NGA) for authority to import natural gas into the U.S.A. from Canada.

TAPCO filed two additional applications (FPC Docket Nos. CP 77-100 and

CP 77-102) on December 20, 1976, for authorization to construct, operate and maintain natural gas transmission facilities at the border between the U.S.A. and Canada and through the states of Maine, New Hampshire, Massachusetts, New York and Pennsylvania. Concurrently, on December 20, 1976, the TGP applied to the FPC (FPC Docket No. CP 77-103) for authorization to modify its existing pipeline facility to enable it to receive the TAPCO natural gas.

By notices issued January 6, 1977, these applications were consolidated by the FPC under Docket No. CP 77-100, et al., for hearing and disposition because they involved common questions of law or fact. On February 12, 1977, the Commission issued an order directing applicants to perfect applications and granting petitions to intervene. Several deficiencies, some of which were later rectified by supplements to the applications, were enumerated in the order.

Subsequently, on March 22, 1977, TAPCO submitted a supplement to its application. This filing consisted of studies by TransCanada concerning its proposed pipeline from the LNG terminal to the point of interconnection with the proposed TAPCO facilities at the Canadian-U.S.A. border. The supplement included engineering cost data and a construction schedule for the proposed 66-mile pipeline.

A second supplement to the application was filed by TAPCO on April 1, 1977, and contained data as to the design, layout, capital costs and service charges for the proposed regasification terminal near St. John, New Brunswick, Canada. Prepared testimony by Sonatrach covering its investment in the proposed Algerian liquefaction facilities was submitted as part of this supplement. Additional data was also provided concerning Algerian natural gas reserves and availability, and the Sonatrach sales contract.

In November 1977, the Canadian National Energy Board (NEB) issued its Decision2/ on aspects of this project within its jurisdiction. Included in the NEB Decision is a provision which allows for up to 5 percent of the annual LNG imported under this contract to be made available to New Brunswick, Canada, consumers.3/

TAPCO and TGP again supplemented their applications on July 1, 1977, by modifying the location of the proposed TAPCO pipeline. TAPCO was advised by the Public Service Company of New Hampshire that the company owned or controlled an electrical transmission tower and accompanying right-of-way that traversed the Merrimack River that could be used as an alternate route. Although the alternate route is marginally longer, the applicants are of the opinion that fewer environmental constraints would have to be overcome by using the alternative route.

On May 5, 1977, the FPC issued an order providing for a hearing, prescribing procedures and granting additional petitions to intervene. The Commission found that significant questions raised by these applications required a formal public hearing. Among the issues deemed relevant by the Commission for consideration were (1) the reliability of the foreign supply; (2) the dependence of certain distributors on foreign LNG to serve residential and commercial markets; (3) environmental impact of any proposed action; (4) the proper method of pricing of the LNG supply, shipping costs, and overall economic feasibility of the project; (5) end-use allocation of the LNG supply; (6) availability of alternate fuels for the markets to be served by the project; (7) engineering feasibility of the project; and (8) overall safety.

In an effort to reduce the need for successive trips by the Algerian representatives, the Commission ordered joint limited evidentiary hearings to commence on July 15, 1977. The hearings were to include both the TAPCO and the Distrigas application.4/ The subject for the hearing was to be Algerian gas reserves and contractual arrangements.

The Commission issued a schedule for the proceedings which called for full hearings to commence on July 14, 1977 and culminate in an initial decision on November 2, 1977. The hearings were to be concluded on September 03, 1977, but were reopened to permit the filing of late evidence and were concluded on October 17, 1977.

On October 1, 1977, the Department of Energy (DOE) was activated pursuant to Executive Order No. 12009, dated September 13, 1977 (42 F,R. 46267) and the function to approve natural gas importation was vested in the Secretary of Energy pursuant to Sections 301 and 402(f) of the DOE Organization Act (Pub L 95-91) (the Act). The Secretary delegated to the Federal Energy Regulatory Commission (FERC, or the Commission) the authority to continue the review of certain pending cases and issue initial decisions of the Administrative Law Judge (ALJ). (DOE Delegation Order No. 0204-1, paragraph 11, October 1, 1977). By a DOE Final Rule issued October 1, 1977, entitled "Transfer of Proceedings to the Secretary of Energy and the Federal Energy Regulatory Commission," this case was to proceed at FERC until the issuance of an initial decision by the presiding ALJ, whereupon the record was to be transferred to the Secretary for decision.

Administrative Law Judge Nahum Litt issued his Initial Decision on Importation and Sale of Algerian Liquefied Natural Gas (Initial Decision or I.D.) on November 2, 1977, in which, subject to conditions, he approved the various applications, as amended, of TAPCO and TGP. Briefs on exceptions were filed by November 25, 1977, and briefs opposing exceptions were filed by December 7, 1977. On December 12, 1977 the record in this case was forwarded to DOE in compliance with the Final Rule. Pursuant to paragraph 6 of DOE Delegation Order No. 0204-4, issued October 1, 1977,5/ the Secretary delegated the authority to issue a final order in this proceeding to the Administrator of the Economic Regulatory Administration (ERA).

The Administrator of ERA heard oral argument on a wide range of issues germane to the case in New York City on July 18, 1978.6/ Written comments on oral argument were received up to August 8, 1978.7/

2. Initial Decision

The presiding ALJ approved the applicants' proposal subject to certain tariff conditions as discussed below.

The ALJ addressed TGP's need for the gas and concluded that the evidence presented by the applicants clearly indicates that TGP will undergo a serious short-fall in meeting the FPC priority of service categories 1 and 2 full system entitlement requirements8/ of its customers over the next 20 years. He reasoned that TGP's 20-year supply analysis showing the need for the gas are the best estimates available, and must be accepted as appropriate for the task. (I.D., p. 72.)

TGP's estimates of its priority 1 and 2 requirements are derived from its perspective as a pipeline supplier and its analysis of its total contractual obligations to deliver gas to all of its customers. As such, they do not contain evidence of TGP's individual gas utility customers' need for TGP's gas with or without the supplemental LNG supply, and the ALJ made no findings on the utility customers' needs.

The ALJ's findings with regard to the existence of a need for the gas further contain the hypothesis that

> . . . even if Tennessee [TGP] significantly understated its prospects and a temporary surplus should occur as a result of the influx of gas supplies on the Tennessee [TGP] system substantially in excess of those now projected to be available, such surplus could not be expected to `e permanent and could undoubtedly be disposed of in the market. [Footnote omitted] Absent a virtual explosion of domestic gas supplies (hardly a reasonable expectation), almost every eastern pipeline could easily take any surplus if Tennessee [TGP] should have the good fortune to attach it to its system.9/

The ALJ's decision and the record are silent on the national need for the LNG.

The ALJ approved, without modification, the LNG purchase contract between Sonatrach and Tenneco LNG which establishes the FMB price of LNG. FERC Staff had raised objections concerning the proposed tariff provision which allows automatic flow-through of the FOB price escalation that uses the posted

New York Harbor prices of No. 2 and No. 6 fuels as escalators. The FERC Staff suggested that each such increase in the FOB price be subject to a full rate review under Section 4 of the NGA.

Judge Litt also concluded that unchallenged evidence of record supports the conclusion that Algeria has adequate natural gas reserves and delivery facilities with which to meet the supply obligations of the TAPCO contract.

Although an LNG shipping agreement between Sonatrach and Tenneco LNG had not been consummated prior to the initial decision, Judge Litt did review a contract between El Paso Eastern and Sonatrach which he assumed could serve as the probable model for any Tenneco-Sonatrach agreement. On this premise, the ALJ approved a basic framework for any future Tenneco freight rate agreement by citing the standards set forth in the ALJ's initial decision in the Pac Indonesia case.10/ The ALJ concluded that "no question has been raised by any of the parties respecting the reasonableness of the transportation charges for the Algerian shipping under the standard announced in the Pac Indonesia Order."

Judge Litt took strong exception to all aspects of the proposal involving the construction and operation of the ships to be supplied by Tenneco LNG. The Judge noted that, since Tenneco subsidiaries were involved in all of the agreements, there was an absence of arms-length bargaining. He concluded that Tenneco's requested rate of return on its ships was excessive in relation to the low level of risk to be assumed, and ordered that TAPCO submit a revised transportation contract that would either reflect a lower rate of return on equity or place Tenneco's equity in the U.S.A. vessels at risk.

The proposal to locate the LNG regasification terminal in New Brunswick, Canada (Tiner Point), and the associated environmental issues related to the U.S.A. segment of the pipeline received considerable attention in the Initial Decision. Judge Litt approved the Tiner Point location by concluding that neither Staff nor other concerned parties were able to locate a more suitable location. Judge Litt also adopted the pipeline route as proposed by the applicants, after reviewing proposed alternative alignments in the pipeline route and without imposing any additional environmental constraints.

In its application, TAPCO proposes to flow through all of its costs to TGP via a cost-of-service tariff. The ALJ rejected TAPCO's request and instead imposed a straight volumetric initial rate with a minimum bill provision. He stated that the TAPCO proposal would expose consumers to an unusual level of risk in light of the high return sought by the applicants.

Judge Litt further rejected TGP's requested revision of its Purchase Gas

Adjustment Clause (PGAC) which would permit automatic flow through to its customers of all costs incurred from the introduction of the TAPCO supply. Instead, he required TGP to make annual rate filings under Section 4 of the NGA that reflect only the costs incurred in introducing the TAPCO supply. He also reduced TAPCO's requested annual rate of return from 18 percent to 15 percent, and its annual depreciation rate from 5.5 percent to 5 percent.

Sonatrach had insisted that it needed a decision on the applications by the end of 1977 or early 1978 in order to schedule the orderly and timely financing of its Valorisation Hydrocarbon Development Program (VALHYD). Sonatrach stated that significant delays in approval would not be in Algeria's best interest, and should this happen, Algeria would attempt to sell its energy elsewhere. Responding to Sonatrach's urgings, the FPC, by order issued May 5, 1977, required that the hearing process be completed by November 1977 and an order issued by the end of 1977.

Judge Litt adhered to the stringent timetable set for him by the FPC and certified the record as sufficient for decision. In Judge Litt's words:

> This case represents the barest minimum showing that could possibly be made to justify certification [of the record] under normal regulatory processes and it is by no means hyperbole to state that but for the overriding energy crisis and the Sonatrach position, there are enough questions still extant to suggest the need for further more leisurely evaluation of the applications. . . . (I.D., p. 6.)

3. Briefs on Exceptions and Briefs Opposing Exceptions

Several of the parties to the proceeding filed briefs on exceptions and briefs opposing exceptions11/ to the Initial Decision. The issue of alternate siting for the LNG terminal received considerable attention. The FERC Staff advocated selection of a U.S.A. site for the proposed terminal, and favored either Prudence Island, Rhode Island, or Sears Island, Maine, on the grounds that these sites were proximate to population centers and nearby natural gas customers. Furthermore, the Staff argued that the analysis of alternate sites based upon the site selection method described in the Final Environmental Impact Statement (FEIS) met the requirements of the NGA and the National Environmental Policy Act of 1969 (NEPA).

Several parties objected to the Staff's position on the site selection process and supported Judge Litt's approval of the New Brunswick site. For example, the State of Rhode Island specifically noted that even if the Prudence Island site were available for development it would remain unavailable for TAPCO's use in developing an LNG facility because the State intended to acquire the property for recreational development. Central Maine Power argued that Sears Island, Maine, was the only available site suitable for a nuclear power plant and should not be used for an LNG facility.

In addition, some parties raised additional comments, asserting that the FEIS was inadequate because it failed to consider a number of factors such as effect on wetlands, effect on wildlife, danger to nearby population centers and failure to meet other NEPA requirements.

The proposed route for the TAPCO pipeline was also criticized. The Natural Resources Council of Maine objected that the Canadian site would result in a major portion of the pipeline being routed through Maine and took exception to the initial decision's rejection of proposed alternative LNG sites on the eastern portion of the North Shore of Long Island, New York. Objections were also raised concerning the lack of consideration for proposed alternate routes that would have diverted the pipeline from environmentally sensitive areas.

The ALJ approved the tariff provision which allows the price of the LNG to be rolled-in to TGP's base gas rate. Several parties, including the applicants, reiterated arguments opposing any concept of incremental pricing, stating that project financing would be unobtainable and that incremental pricing would be difficult to administer. Those parties supporting incremental pricing urged that such a mechanism would promote the development of domestic gas supplies and conservation in gas consumption.

Only FPC Staff addressed the FOB escalator provisions approved by Judge Litt. In its brief the Staff reiterated the position it had taken during the evidentiary hearings that the FOB escalator did not comply with the NGA and that the price indices used would be sensitive to political judgments of foreign nations.

4. Discussion of Oral Argument

Oral argument was held in New York City on July 18, 1978, Administrator Bardin presiding.12/ Issues for argument included the probable effect on U.S. international interests and balance of payments; the mechanisms by which the cost of the gas would be determined; the need for and supply of natural gas in the relevant market areas; and the adequacy of the record. The oral argument in New York was supplemented by written statements and comments filed with ERA by participants and other interested parties.13/

The applicants submitted extensive background and supplemental materials which asserted that (1) siting the terminal facilities in Canada posed no problems; (2) alternative sites in the United States were adequately studied and none was found significantly superior by the FPC to warrant rejection of the Canadian site; (3) the balance of payments and general economic activity of the U.S. would be affected favorably by approval of the project; (4) the Sonatrach sales contract provisions were reasonable and necessary to assure financing of Algerian facilities and feasibility of the project in general; (5) a cost-of-service tariff for the shipping portion of the project and rolled-in pricing of the regasified LNG were essential to obtaining financing for the project; and (6) the LNG was needed to serve high-priority customers on the TGP system.

One of the issues on which ERA requested oral argument was,

> . . . how much of the LNG could be marketed if it were sold to each purchasing distribution utility on individual, separate contracts? 14/

Applicants stated that,

> In light of the above question, Tennessee [TGP] recently surveyed its 20 largest customers, who purchased 90 percent of Tennessee's [TGP's] sales volumes, to determine the volume, if any, of the regasified LNG from this project they would be willing to purchase if offered on a separate 100 percent take-or-pay for contract basis. Only three of the customers indicated that they would be willing to purchase any gas on such a basis and the total volume for the three was approximately 150,000 Mcf per day. Obviously, such a small volume would render this project infeasible.15/

At oral argument, applicants referred to this survey and repeated the statement that "the total amount they [the customers] would be willing to buy . . . obviously would make this project infeasible." (Transcript, I, pp. 28-29.)

In response to the Administrator's request for further information on the survey, including its methodology and the answers received (Transcript, I, pp. 29-31), applicants provided the following statement subsequent to oral argument:

> The only way in which the TAPCO gas could be resold on an incremental basis and, at the same time, satisfy lender requirements as to financiability would be for Tennessee [TGP] to enter into separate, individual contracts under which credit-worthy customers would agree to purchase TAPCO gas at its full cost on a 100 percent take-or-pay-for basis. In order to form a basis of credit support upon which lenders could agree to advance funds, such contracts would of necessity have to be entered into now, prior to the time the facilities are constructed and gas begins to flow and would have to contain minimum bill provisions similar to that contained in TAPCO's proposed tariff. Moreover, lenders would require that the respective state commissions approve such contracts for their utilities in advance of the loans.

In order to determine the feasibility of such a marketing program, Tennessee [TGP] . . . conducted a survey . . . to determine the volume, if any, of TAPCO gas each customer would contract presently to purchase at a cost of as high as $6.00 per Mcf in 1985 (such price allowing for delays in the project) under certain conditions and assumptions necessary to effect financing even on this basis.

Included among such conditions was a contractual obligation to-take-or-pay-for 100 percent of the daily volume of TAPCO gas contracted for. . . .

Moreover, the assumption was that no assurance could be provided that the contract volumes would not be curtailable. . . .

In addition, it was assumed that the contract would include a minimum bill obligation, as provided for in TAPCO's proposed tariff, which would make the customer liable for his proportionate share of project operations and maintenance expenses, debt service obligations and equity investment in the project in the event the project should abort at any time during the term of the contract.

. . . None of the customers indicated a willingness to enter into contracts presently to purchase TAPCO gas. [footnote omitted] Each gave as a primary reason for its refusal the uncertainty surrounding projections as to the competitiveness of the TAPCO gas at $6.00 per Mcf vis a vis competing fuels in the mid-1980's which precludes it from committing now to purchase this gas under separate contracts involving a daily take-or-pay-for obligation. . . .

In addition, numerous other reasons were given by various customers surveyed. For instance, Tennessee's [TGP's] wholesale customers surveyed indicated that all other things equal, they could lot enter into purchase contracts absent prior explicit and irrevocable assurance from FERC that they would not in turn be required to resell the gas incrementally. Retail distribution customers likewise voiced the need for prior assurance that they would not be required by their state commissions to resell the gas incrementally.

A number of customers cited the curtailability of the contracted volumes as a factor contributing to their unwillingness to presently contract; and small customers on East Tennessee Natural Gas Company's system pointed to the low load factor nature of their system operations as a further reason why they are unable to contract. . . . (Applicants' "Supplemental Comments," August 18, 1978, pp. 19-21.)

Concerning the discrepancy between applicants' earlier statements that three customers had indicated a willingness to purchase TAPCO gas, and the subsequent statement that none of the customers indicated such a willingness, applicants explained:

> . . . it appears that each of these three customers had understood the original offering as not requiring a present commitment to purchase, but rather an offer to purchase in the mid-1980's when LNG became available. Subsequently, each has expressed an unwillingness to make a present commitment to purchase for the reasons indicated above. (Supplemental Comments, p. 21).

Applicants also attempted to clarify other discrepancies in connection with TGP's telephone survey:

> In contacting its customers, Tennessee [TGP] did not suggest any volume restriction. However, as indicated at the oral argument, Northern Indiana Public Service Company, a customer of Midwestern, apparently understood Midwestern's communication to them as a proposed offering of a pro-rata portion of the LNG volume. We do not believe that customers contacted by Tennessee [TGP] directly understood there to be any such restriction on the proposal. In any case, it is a moot question since all customers, except the three named [Orange and Rockland Utilities, Inc., Northern Illinois Gas Company, and Northern Indiana Public Service Company, the latter two being customers of Midwestern, which in turn is a customer of TGP] were unwilling to commit to purchase any volumes under separate contracts. (Applicants' Supplemental Comments, Appendix B, p. 2.)

In addition to this somewhat confusing description of the market survey presented by applicants, several customers submitted information directly to ERA.

Columbia Gas Transmission Corporation (Columbia), one of TGP's customers which was surveyed, stated to ERA that, although it supports the TAPCO project as proposed by applicants, it "could not agree to commit itself to purchase any LNG under the assumptions posited at the present time." (Letter from Columbia to Administrator Bardin, August 2, 1978, responding to questions raised at oral argument, p. 2.) Columbia stated that it could not afford to risk purchasing LNG under separate contract on a 100 percent take-or-pay basis without some assurance that it would be able to resell all the gas. A second reason given by Columbia for its unwillingness to enter into a separate contract was "the uncertainty surrounding whether the LNG would constitute firm, noncurtailable service by Tennessee [TGP]." (Ibid.)

During oral argument, the Administrator had asked why Columbia was unwilling to enter into a separate contract with TGP when its affiliate, Columbia LNG, had recently filed an application to import LNG from Iran and to sell the LNG to Columbia. Columbia responded, subsequent to oral argument:

> First, it should be noted that Columbia Transmission proposes to sell the regasified Iranian LNG to its customers on a rolled-in basis, and does not propose to enter into separate contracts with its customers for the sale of this LNG. Under this proposal, Columbia Transmission sees little problem with the marketability of such LNG. Second, Columbia Transmission will be receiving all of the gas to be imported by Columbia LNG. Therefore, there should be no circumstance whereby such LNG would be allocated to others during the life of this project. (Letter, p. 3.)

Northern Illinois Gas Company (NI-Gas) also stated that it was unwilling to make a present commitment to purchase any TAPCO gas in the future, and would consider purchasing such gas, when and if it became available, only in the context of an analysis of its needs, regulatory restrictions on gas markets, and alternative supply sources at the time. (Letter to ERA, August 8, 1978.)

Pennsylvania Gas and Water Company (PGW) expressed the view that little if any of the TAPCO LNG could be marketed if it were sold to each distribution utility on a separate contract basis "at the projected 1985 price of $6 per Mcf." According to PGW, "with the uncertainty of the sales in the market for each distribution company, it is most likely that the total LNG from the TAPCO Project would be substantially undersubscribed which would undoubtedly jeopardize the entire project." (Presentation on Issues, July 27, 1978, p. 2.) PGW did assert that TAPCO LNG was critical to PGW's ability

> . . . not only to meet demand, but to provide reasonable pates--the alternatives being to not only force the customer to use electricity at much higher rates but also the conversion cost of equipment which would average at least $2,000 for the residential customer.
>
> Specifically, the TAPCO Project will provide 51% of our Tennessee [TGP] total supply in the 1985-86 period. Absent this supply we would only receive 69% of Priority 1 requirements in the 1985-86 winter period . . . This domino effect on supply imbalance will cause decreased sales to Priority 2 customers with higher rates for the remaining customers to enable the Company to recoup its total costs. (Presentation on Issues, p. 4.)

PGW, accordingly, urged approval of the project with rolled-in pricing.

While not disputing the need for the LNG in TGP's system, the Brooklyn Union Gas Company (Brooklyn Union) affirmed its position that it would not be willing to purchase any of this LNG. It did, however, urge that TAPCO LNG be priced incrementally at the wholesale level, with sales to each purchasing distribution utility on the basis of separate contracts. Brooklyn Union rejected the

> . . . burner-tip oriented pricing scheme proposed by the FERC staff (Tr. I, 88-93). Pricing at the retail level, which is the responsibility of individual distributors subject to the requirements of local law and the rules of local regulatory commissions, should not be confused with the wholesale pricing issue in this case. (Information Response and Comments of the Brooklyn Union Gas Company, August 17, 1978, p. 1.)

Incremental pricing, according to Brooklyn Union, would channel the benefits of the LNG project to those distribution company customers of TGP which wanted and needed the LNG, and would assure that the costs of the project were borne by those who would benefit from it. If it is true, however, that incremental pricing would be fatal to the project by rendering it unfinanceable

> . .. some mechanism must be developed to reconcile rolled-in pricing with the public interest, so that distributors who need and want TAPCO LNG will not be deprived of this supply, while distributors who do not need or want the supply will not be burdened with the costs of the project.
>
> Such a mechanism would be a modified or conditional rolled-in pricing system, under which any Tennessee [TGP] customer who could establish that it did not need the supply, . . . and who relinquished its right . . . to any share of the supply, would be entitled to continue to receive Tennessee [TGP] gas under a rate schedule that excluded the gas costs and associated storage costs , . . of the TAPCO project. (Information Response, p. 2.)

Brooklyn Union asserted that since TAPCO LNG would be purchased at a specific price at existing delivery points on TGP's system, there would be no difficulty in determining the volume and cost of the LNG and developing "TAPCO-inclusive and TAPCO-exclusive rates for Tennessee [TGP] gas." (Ibid.) The TAPCO-exclusive rate schedule would exclude the gas and storage costs of the TAPCO supply, but not the cost of TGP facilities to be constructed for the transportation of the supply, since such facilities presumably would be used at some time for the benefit of the entire system.

Brooklyn Union's argument for modified rolled-in pricing was related to its situation as compared to that of other TGP customers:

> Due to curtailments, TAPCO LNG will not inure to the benefit

> of all Tennessee [TGP] customers, but will enable some customers to serve priority 3 and 4 markets (Tr. III, 71), while the priority 1 residential consumers of other Tennessee [TGP] customers, who have no priority 3 or 4 markets, would be forced, under rolled-in pricing, to underwrite the costs of this project from which they will derive little or no gas, at present or in the future. . . . (Information Response, p. 3.)

According to Brooklyn Union, the reason that it did not need TAPCO LNG is that it was forced to acquire high cost supplemental supplies such as LNG and SNG

> . . . on a self-help basis, long before the TAPCO project was even formulated.
>
> When confronted with curtailments by Tennessee [TGP] and its other pipeline suppliers, Brooklyn Union, unlike other Tennessee [TGP] customers, did not have large industrial customers to curtail and could not, without unacceptable risk to life and property, operate its grid distribution system on a selective shut-down basis. . . . It was required to contract (with Distrigas Corporation) for the delivery of LNG starting in 1974 and to construct an SNG plant that went into service in 1975. . . , (Information Response, pp. 3-4.)

The company stated that its LNG and SNG

> . . . have been obtained at their incremental cost. These costs have not been rolled into the rates charged other Tennessee [TGP] customers, but are borne in their entirety by Brooklyn Union consumers. . . . (Information Response, p. 4.)

Accordingly, Brooklyn Union was

> . . . willing to relinquish to those Tennessee [TGP] customers who claim to need TAPCO LNG, this Company's share of that supply. However, Brooklyn Union should no more be burdened with the costs of TAPCO LNG, than other Tennessee [TGP] customers are burdened with the costs of Brooklyn Union's LNE. (Ibid.; also see Transcript of Oral Argument, II, p. 42.)

Applicants' response to Brooklyn Union's position was that TGP operates an integrated system in which transmission and supply costs are shared on a rolled-in basis.

> Every action taken by Tennessee [TGP] cannot benefit every customer on the Tennessee [TGP] system equally, but the pluses and minuses even out over time on an integrated system.

> Moreover, Brooklyn Union's claim that it would be willing to renounce any claim to this supply forever must be taken with a grain of salt, for as counsel for PSCNY realistically observed (ERA Tr. 1/120), under any circumstance `. . . you can't cut off residential [sic] in a city like New York.'
>
> Brooklyn Union cannot have its cake and eat it too. It can't renounce this supply, but retain the option to buy some other lower priced supply from Tennessee [TGP] in the future to meet its contract demand. Moreover, it can't renounce supplies purchased by its pipeline suppliers to meet existing contract demand, while at the same time retaining a right to buy more than its pro-rata share of existing low-cost gas supplies. (Supplemental Comments, pp. 8-9.)

The Council on Wage and Price Stability submitted a "Statement in Lieu of Oral Argument" (July 18, 1978) which addressed, among others, various pricing and marketing issues.

> The Council continues to believe that the issue of incremental v. rolled-in pricing of LNG is an extremely important one, pervading and overshadowing all others insofar as inflationary consequences are concerned. (Statement, p. 2.)
>
> The Administrative Law Judge in this case held that incremental pricing was not in the public interest, even on the theoretical level. However, we are inclined to the view that his principal grounds for rejecting it were primarily practical. [footnote omitted] Even so, we believe that the practical problems associated with incremental pricing have been unnecessarily blown out of proportion: . . . (Statement, p. 16.)

The Council rejected applicants' position that imposition of incremental pricing would render the project unfinanceable:

> The Council believes that unless costs have been significantly underestimated, the LNG in this project should be saleable at a price equal to its incremental cost to high priority or low priority customers, or both. (Statement p. 17.)
>
> Another argument against incremental pricing at the wholesale level is that State regulatory commissions would not likely allow incremental pricing at the retail level. [footnote omitted] We believe that many of the benefits of incremental pricing that accrue at the national level would also accrue at the State level. For example, the benefits of greater efficiency and conservation and the equitable distribution of `regulatory gain' that are induced by incremental pricing

> are desirable objectives at the State level. . . . Thus, there is every reason to believe that State regulatory commissions would recognize the benefits of incremental pricing. (Ibid.)
>
> Incremental pricing is also criticized for remaining entirely theoretical in as much as no specific and detailed implementation scheme has been offered . , . . It seems to us that the burden of designing a prototype rate scheme which embodies incremental pricing must reside with Tennessee [TGP] (for the wholesale sector) and the distribution companies (for the retail sector). The design of such an illustrative but realistic scheme would require a considerable amount of detailed information, possessed only by those companies, on customer profile, supply and demand, costs, and more importantly, on policy assumptions appropriate to pipeline and locale regarding the treatment of income levels and gas uses. It may be pointed out in this connection that the extremely complex incremental pricing provisions of the natural gas compromise are also left to `e implemented by gas pipelines, distribution companies, the Federal Energy Regulatory Commission (FERC) and State regulatory commissions.
>
> In conclusion, in the Council's view, incremental pricing at the wholesale level is in the public interest and would, in and of itself, have no adverse impact on the marketability of the LNG imported under this project. Of course, rolled-in pricing would . . . impart greater certainty to the project's economic viability, but it has other consequences which, as pointed out, are not in the public interest. (Statement, p. 19.)

Another perspective was provided by the Process Gas Consumers Group (PGC), whose stated purpose is to promote the development of governmental policies assuring an adequate supply of gas for industrial uses which cannot technically or economically be converted to alternate fuels. The individual members of PGC which participated in the TAPCO oral argument, and which submitted "Rebuttal and Supplemental Comments" dated August 18, 1978, are Cone Mills Corporation, Libbey-Owens-Ford Company, General Motors Corporation, and Nabisco, Inc.

Although PGC expressed agreement with applicants on the issue of rolled-in pricing, PGC disagreed with applicants' position on risks to be borne in the event of project failure:

> . . . PGC objects to financing methods and tariff provisions which would require its members to bear the costs of any LNG import project prior to or subsequent to the time that its facilities are used and useful. This is particularly the case in situations in which the

> continuing depletion of existing supplies means that there is an increasing probability that, when the LNG comes on line, it will be needed to serve the highest priority customers and will not be available even for industrial process uses. . . . (Rebuttal, p. 4.)

PGC objected to applicants' asserted need for "project financing," and argued that such a mode of financing might be avoided if applicants were willing to use less debt and commit more equity. Applicants' response to this criticism was that,

> Since the outset of this project, Tenneco has been seeking to interest other equity investors to undertake significant aspects of the project. One thing has been made clear: no party has expressed any interest in investing in this project, except on a project financing basis. . . .
>
> In the final analysis, TAPCO's minimum bill simply involves the credit strength of the consumer necessary to support the financing of the project. It redounds to the benefit of the consumer by enabling financing at the lowest reasonable cost for a project which will provide millions of consumers with needed gas supplies . . . (Supplemental Comments, pp. 14-15.)

Socioeconomic and environmental issues were prominent features of the oral argument. The National Resources Council of Maine, for example, combined objections to lack of adequate consideration of alternatives with objections to rolled-in pricing:

> One of our particular concerns has been the obvious economic waste, as well as the environmental costs, involved with the construction of a five hundred mile pipeline from New Brunswick to New York, when the record discloses a preferable location for the terminal and regasification facility in closer proximity to the distribution points for the gas. The . . . [Statement in lieu of Oral Argument of the Council on Wage and Price Stability] makes it abundantly clear that the adoption of incremental pricing would help to avoid or minimize project costs, including such costs that would not be readily controlled under a rolled-in pricing system. (Comments Supplementing and Responding to Statements Made at Oral Argument, pp. 3-4).

The Department of Energy of the State of New Jersey stated that the TAPCO project would encourage the use of LNG for base-load purposes, and that,

> As a matter of policy, the State of New Jersey believes that LNE activity should be closely regulated and limited strictly to peak-shaving and very low priority base-load use.

> . . . we oppose the Tenneco proposal out of concern for the safety of our citizens and as contrary to sound energy policy. (Transcript, II, p. 15.)

New Jersey also argued against increasing American reliance on foreign energy sources.

> At a time when Western European nations have shown success in cutting their dependence on foreign fuels, the United States has increased its vulnerability, with inflation and major balance of payments problems as a result. Energy independence is the cornerstone to the long-term viability of our economy. Any action which impedes progress towards achieving that goal should be flatly rejected. The Tenneco proposal is such an action and in our view . . . should not receive . , . approval. (Transcript, II, p. 16.)

The Job Development Authority and the Department of Commerce of the State of New York, in a joint statement, discussed the development of

> . . . an off-shore energy island complex as one possible answer to the city's and state's economic energy ills. Known as ICOM, Island Complex offshore New Jersey, the state is investigating the feasibility of constructing a 32,000 acre island twenty-three miles south of the Verrazano-Narrows . . . . The ICOM would be the home of heavy industry necessary for, but ecologically unsuitable to a major metropolitan area. (Transcript, III, p. 47.)

As part of ICOM, New York envisioned an LNG terminal that could

> . . . goes a long way towards resolving many of the potential harms associated with building a natural gas pipeline from New Brunswick . , . to the New York metropolitan area.
>
> For one, we believe ICOM is the cheapest and most efficient means of delivering LNG from any supplier to the northeast market. . . . (Transcript, III, pp. 48-49.)
>
> In terms of safety the ICOM concept goes a long way towards satisfying the legitimate concerns of many people that LNG tankers and terminals should not be permitted in or near densely-populated areas . . . . (Transcript, III, p. 49.)

In addition, the length of pipeline required to connect an LNG terminal on ICOM to the New York market would be only twenty-five miles, most of it buried beneath the sea bed.

> Therefore, it is clear to us that before any permit be issued to construct and operate an LNG import terminal, pipeline from Canada to the New York metropolitan area, further studies should be undertaken to establish whether projects, such as ICOM, are the better alternative to meeting our energy requirements in the northeast. (Transcript III, p. 50.)

FERC staff reiterated its position that Prudence Island, Rhode Island, was the most desirable site for the TAPCO project, and that cost savings and other factors associated with the U.S. site militated against approval of the Canadian site. Reduced pipeline distance, reduced construction impact, more protected harbor with less severe weather and sea conditions, proximity of Prudence Island to ship-building and industrial areas, and availability of a skilled labor force were mentioned by FERC staff as among the considerations which led it to favor the U.S.A. site. FERC staff expressed the view that even at the risk of causing the project to be abandoned, the Prudence Island site should be chosen in preference to the New Brunswick location. (Transcript, I, pp. 80-81.)

Prudence Island found further support from an official of the United Brotherhood of Carpenters and Joiners of America, Local #176, Mr. Rodney P. Bowley:

> Why should the American gas consumer, a hundred and fifty thousand who reside in Rhode Island, be expected to absorb an additional 300 million dollars in charges, especially when the citizens of Canada will derive all of the benefits of the jobs and the property taxes created by this project? (Transcript, III, p. 62.)

Mr. Bowley argued that the Rhode Island building tradesmen should be able to benefit from location of the terminal and associated facilities in his state. "The construction jobs in this project belong to Americans." (Transcript, III, p. 63.)

> My remarks are probably not in the proper form, nor presented in the manner in which you are accustomed. I am here because I believe in what I said, because I believe the man who puts the tool box on his shoulder is just as important to this government as the governor of Rhode Island or the president of one of the giants of American industry, and that he deserves all of the guarantees under the Constitution regardless of his financial assets. (Transcript, III, p. 66.)

The Canadian site, on the other hand, was defended by applicants and by the Honorable Richard Hatfield, Premier of the Province of New Brunswick. The Premier expressed support for the proposed TAPCO terminal site and gas pipeline route to the U.S.A. border. Many energy companies, he asserted, had thoroughly investigated the Lorneville Peninsula and adjacent deepwater port and found the site to be ideal for very large ships and for uses such as gas terminalling.

> Experts which include the world's leading authorities in their fields, together with our most knowledgeable local mariners and pilots have endorsed this as an excellent site for these purposes.
>
> In all cases the companies were fully satisfied with the location and site conditions, and indeed had selected the site after considering all other possible sites in Eastern Canada and the United States. (Transcript of Oral Argument, II, pp. 20-21.)

The Premier pointed out that the Province of New Brunswick had carried out a detailed environmental impact study with the joint sponsorship of the Canadian Federal government; that the City Council of Saint John, New Brunswick, after public hearings, had zoned the area for use by heavy industry, including oil and gas terminalling and processing; and that the National Energy Board and the Ministry of Transport of Canada had granted authorization for the proposed LNG import terminal. A power plant owned by the New Brunswick Electric Power Commission is adjacent to the proposed LNG terminal site, and the Premier indicated that the use of warm water effluent from the plant would conserve energy needed for vaporizing LNG and benefit the environment by reducing the temperature of water discharged to the sea.

The Premier also indicated that unemployment in New Brunswick was high and development opportunities limited.

> The short term effect of an average of 700 construction jobs for 4 and one-half years on the province would be most beneficial, while the full time direct jobs and associated spin off employment is a promising long term benefit.
>
> This project has the full support of the Province of New Brunswick. The safeguards necessary and required to protect our environment will be met, the companies know and accept this. That they will be good corporate citizens, I have no doubt.
>
> There is overwhelming support from all sectors of our community for the project . . . . (Transcript, II, p. 23.)

One issue which applicants raised at oral argument concerns the estimated price of LNG from the TAPCO project compared to DOE projections of the cost of coal gas, Alaskan gas, and other new domestic natural gas. Applicants indicated that the cost of TAPCO LNG, at the burner tip, would be \$5.59 per Mcf in 1986 dollars, and asserted that this compared favorably to recent DOE estimates of burner tip costs, in 1985 dollars, for various sources of supplemental gas.16/

C. ERA'S Responsibilities on Review of Natural Gas Import Applications

Under Sections 301 and 402(f) of the DOE Organization Act (DOE Act), the Secretary of Energy has the authority to authorize the import or export of natural gas pursuant to Section 3 of the NGA and to permit the building and operation of border facilities pursuant to Executive Order No. 10485. The Secretary delegated this responsibility to the Administrator of the ERA on October 1, 1977,17/ and it was under this delegation that ERA considered the TAPCO application and held oral argument. More recently, the Secretary has issued two delegation orders which redefine the areas of jurisdiction between ERA and FERC in deciding applications to import natural gas.18/

The new delegations recognize the diversity of functions between the Secretary and the FERC and provide a mechanism whereby the Secretary, through ERA, maintains control under Section 3 of the NGA over natural gas imports to the extent that they concern energy policies on an international, national and inter-regional scale.19/ Those functions involving supervision of other aspects of specific imports, and particularly the ongoing supervision of any interstate pipeline companies involved, rest within the FERC's jurisdiction.

Under the delegations, ERA and FERC must determine whether an import is not inconsistent with the public interest based on certain considerations inherent in Section 3 of the NGA. In applying ERA's delegation, the Administrator is required to determine certain issues, and if he decides favorably on the application, FERC must then decide any remaining issues.

The issues that ERA must determine are as follows: (1) the security of supply; (2) the effect on U.S.A. balance of payments; (3) the price proposed to be charged at the point of importation; (4) national need for the natural gas to be imported; and (5) consistency with duly promulgated and published regulations or statements of policy of DOE which are specifically applicable to imports of natural gas.

In addition the Administrator has the discretion to consider other factors within the scope of Section 3 of the NGA which he finds in a particular case to be appropriate for his determination. These include regional needs for imported natural gas and the eligibility and respective shares of purchasers and participants. ERA may also review the proposed place of entry and the construction and operation of the terminal facilities, but only on the basis of their impact on security of the gas supply and the import's effect on U.S.A. balance of payments.20/

In considering those aspects of an application that are within ERA's jurisdiction, the Administrator may also attach any terms and conditions which are considered necessary to make the import not inconsistent with the public interest. For example, in appropriate cases, ERA could condition approval of a proposed import with the requirement that the importer sell some or all of the gas directly to state-regulated gas distribution utilities or that the importer sell certain amounts of the natural gas to specified buyers, regions of the country or critical industries. So, too, the Administrator could impose the condition that the importer and his foreign supplier change the terms of the import contract with respect to initial price, the duration of the arrangement or price escalation clauses. The Administrator further could impose the condition that the costs of the import be incrementally priced to the customers.21/

The delegation order makes the FERC responsible for exercising all other functions concerning proposed imports under Section 3 of the NGA which either have not been delegated to ERA or have not been previously exercised by the Administrator. In addition, all functions under Sections 4, 5 and 7 of the NGA as they relate to import applications are exercised by the FERC. Thus, the FERC has the responsibility to approve the siting, construction and operation of particular facilities and the place of entry for an import.

Furthermore, if an importer proposes to sell natural gas in interstate commerce for resale, or to have imported gas transported by interstate pipeline companies, the FERC will review the resale prices and the transportation prices and arrangements under the just and reasonable standard of Sections 4 and 5 of the NGA and the public convenience and necessity standard of Section 7 of the NGA.

If the Administrator determines, on the basis of the considerations within his delegated jurisdiction, that a proposed import is not inconsistent with the public interest, then the FERC will pass upon the remaining considerations and will issue whatever orders, authorizations and certificates are necessary or appropriate to implement the respective determinations made by the Administrator and the FERC. If the FERC issues an order authorizing an import, it must include in its order any terms or conditions previously attached by the Administrator. If the Administrator determines that a proposed import is not consistent with the public interest, his order will be immediately subject to application for rehearing and judicial review under Section 19 of the NGA.

In determining whether the application at issue in this proceeding is not inconsistent with the public interest under Section 3 of the NGA, ERA is applying, for the first time, the terms of the new delegation.22/ In this case, ERA will consider the following aspects of the proposed TAPCO import:

(1) Security of supply,

(2) National need for the gas, including national interstate market need,

(3) Regional needs for the gas, including eastern interstate market needs,

(4) Eligibility of purchasers and participants,

(5) Proposed import price,

(6) Effect of the import on U.S.A. balance of payments, and

(7) Effect of construction and operation of the receiving terminal in Canada on U.S.A. balance of payments.

D. General Considerations

The Natural Gas Act requires a decision whether the proposed natural gas import "is not inconsistent with the public interest." The DOE Organization Act assigned responsibility for that decision to the Secretary of Energy (or his delegates), thereby signifying a mandate to assess each proposed gas import project, taken as a whole, against the objectives of national energy policy.

Gas imports should be viewed in the context of the importance of gas supplies to the U.S.A. energy economy and of the costs of enhancing the domestic gaseous fuel base. In Opinion No. One, we stated:

> Development of new gaseous fuel supplies offers great benefits. Gas is the cleanest-burning fossil fuel. The country has a ready-made infrastructure for delivering gaseous fuel to the consumer. But there are substantial costs involved if we are to add to our rapidly dwindling gas supplies. As conventional, low-cost natural gas resources dwindle, we need a number of unconventional, even exotic, substitutes to replace the conventional. Gasification can turn our abundant domestic coal supply into a clean-burning fuel, but the process is costly. Natural gas from the north slope of Alaska can be transported to the lower 48 states, but the transportation system to deliver it will be the most costly privately-financed construction project in history. In time, we may be able to exploit the large quantities of methane gas locked within difficult-to-penetrate rocks or underground waters, but at significant costs.23/

Indeed, natural gas (basically, methane gas) supplies some 25 percent of our national fuel needs.

In the case of proposed LNG import projects, however, national policy dictates the most cautious--even skeptical--assessment of each gas import project on its overall merits, since LNG generally represents a marginal natural gas supply for the U.S.A. at the present time. This does not mean a blanket rejection of all LNG imports. To the contrary, ERA has permitted such import projects in the past and may well approve others. Yet, mindful that while Federal policy allows some new imports, it does not promote them, we will be particularly reluctant to exercise the full panoply of Federal statutory power on behalf of an LNG import project.

In Opinion No. One, speaking of LNG, as well as other natural gas imports, ERA stated that:

> At the outset, the DOE must carefully weigh implications for national security and the overall domestic energy economy. It must consider such questions as: Is the source of supply physically and internationally secure? How vulnerable are the physical arrangements to interruption by accident or by design, in peace or in war? Are the proposed long-term prices and financial terms in line with the equivalent energy costs of alternative supplies to our economy? Do the proposed pricing arrangements allow responsible scrutiny and choice by state governments and local distribution companies? Is the proposed escalation clause, if any, objective in its reflection of potential increases in the cost of energy? . . .

When an import case involves secure supplies offered at costs below or equivalent to other new energy supplies, with each state-regulated gas distribution utility afforded the right to determine for itself whether its service area requires the volumes offered at their true cost, the DOE may decide the case in light of conventional factors, including markets, allocations, facilities, siting and environmental quality. On the other hand, in a case involving insecure sources or prices that exceed the cost of equivalent energy supplies, the DOE may give more careful scrutiny to whether the project is in effect being inappropriately subsidized by being rolled in with low cost domestic gas, at the expense of future domestic gaseous fuel projects.24/

All fuel imports tend to have some adverse impact, at least in terms of the nation's balance of payments. But, when natural gas is imported in the form of LNG, with its attendant complex technology and long shipping distances, there is a further impact from the necessary vast capital commitments for facilities abroad and tankers on the high seas. There is also a corresponding commitment to import for a long period of time--typically, at least of a quarter century. Hence, a determination of consistency with the public interest requires a balancing to see whether there are beneficial aspects of an LNG proposal which outweight the adverse impacts.

In Opinion Number Two, ERA elaborated a preferred order of gas supplies. We stated that our supply of natural gas should first come from conventional sources in the contiguous U.S.A. (including the continental shelf), which are within the reach of current drilling technology and located near the established pipeline infrastructures.

> National energy policy recognizes the primacy of these proximate supplies of conventional gas, as enterprise develops them and claims access to U.S.A. markets. Other potential supplies are marginal or at least intramarginal with respect to U.S.A. markets, principally by reasons of remoteness (as reflected in the transportation costs) or uncertain technology. Intramarginal supplies include gas from the Alaskan North Slope, various supplies from advanced technology applied to domestic resources, and overland supplies from neighboring sovereign countries, as mutual benefits may dictate such transactions. Marginal supplies include synthetic natural gas (SNG) from imported petroleum and LNG from abroad.
>
> Even though capital-intensiveness, price, long-term commitment and vulnerability make remote foreign LNG supplies most marginal for U.S.A. markets, there is a place for some such projects. We must take care, however, that decisions taken with respect to LNG imports from remote sources do not discourage the ultimate development of proximate resources, and that only those LNG projects are approved in which the need for the gas cannot be satisfied by more basic sources of supply. In that context, we must also protect the consumer from unacceptable risks of escalation in the price of the gas.25/

The Congress also has articulated a preference for domestic supplies. For example, Congress has sought to facilitate the completion of the Alaskan Natural Gas Transportation System as a vital addition to the nation's gaseous fuel infrastructure.26/ Most recently, in the NGPA, Congress has reinforced that preference by providing for rolled-in pricing treatment of the high transportation and other costs required to bring the Alaskan North Slope (ANS) gas reserves to the nation's working inventory of fuels. The conferees agreed

> . .. to provide rolled in pricing for natural gas transported through the Alaska Natural Gas Transportation System and for the cost of transportation because they believed that private financing of the pipeline would not be available otherwise. Rolled in pricing is the only Federal subsidy, of any type, direct or indirect, to be provided for the pipeline.27/

In the case of the infrastructure investment needed to make ANS gas available, Congress and DOE are prepared to exercise substantial Federal statutory authority as an incentive.28/ However, different considerations apply to governmental support for investments in LNG facilities, located mainly abroad, and LNG tankers, which can be described as moveable pipelines. Not only are these projects marginal, but the extensive investment necessary does not add capacity for domestic production.

In reviewing a proposed LNG project, ERA must consider whether the project has the potential of frustrating the development of domestic intramarginal sources of gaseous fuel, such as natural gas from Alaska or synthetic gas from coal. It is in this context that ERA considers the national need for the added gas supply offered by each LNG project.

Moreover, we are convinced that enactment of the NGPA and the Powerplant and Industrial Fuel Use Act of 1978 (FUA) will make more natural gas available, both in terms of overall quantities produced nationally and quantities available to the interstate market.29/ The potential for increased availability is a factor which should be considered in assessing national need.

The NGPA significantly alters the economic and regulatory framework for the development of domestic natural gas. Development of new conventional and unconventional supplies is encouraged through higher wellhead prices and other incentives. Effective December 1, 1978, the NGPA will fix ceiling prices for new gas sales contracted to both the interstate and intrastate market. It will thereby unify the current fragmented gas market and establish in its place an overall national natural gas market. The NGPA will allow for deregulation of deep and hard-to-find gas within a year of its enactment, which will result in additional gas supplies for the U.S.A. gas market in the 1980's. Liberal annual increases in the ceiling prices for first sales of natural gas, to exceed the rate of inflation by as much as 3.5 to 4.2 percent per year, are also authorized. Finally, in the middle or late 1980's, NGPA will have deregulated most gas supplies after gradually weaning the gas market from price controls.

In the meantime, DOE anticipates that the creation of a unified natural gas market will bring, on an annual basis, 0.7 to 1.0 Tcf of what was formerly surplus intrastate gas into the interstate market and make it available to interstate pipeline systems. Also, under the NGPA, domestic supplies dedicated to interstate pipelines can be expected to increase by somewhat more than the total domestic supply increase. The end-use price system under the NGPA, as well as the new coal conversion provisions of the FUA, will induce conversion to coal for some large boilers which should further add to available supplies of gas. Therefore, by 1985, when TAPCO asserts it will reach its full level of deliveries, DOE estimates there may be from 0.8 to 1.1 Tcf/year of additional gas supplies available from Alaska.

These additional supplies should reduce the national need for imported LNG to supply traditional users of gas. However, regional needs for imported gas may differ from those of the country as a whole. ERA will, therefore, evaluate the end-user needs for regional markets, where appropriate.

Regional boundaries depend on the peculiarities of a particular geographic market and do not necessarily coincide with the area served by a pipeline system and its gas distribution utility customers. Where there are special environmental or other factors present, the boundaries of a single state, such as California, may define a regional market. In other instances, the entire eastern half of the country might prove to be the relevant area.

In any event, where regional need is assessed, ERA will look for a demonstration of end-user market need, as opposed to a mere showing of an interstate pipeline company's contractual obligations to deliver gas. The latter evidence would generally be an unreliable indicator of regional need, insofar as it does not reflect the impacts of energy conservation measures, conversion to alternate fuels by low priority customers, and self-help measures taken by end-users and gas distribution companies.30/

Local gas distribution utilities are in the best position to determine the needs of burner tip users. A natural gas distributor has full knowledge of its system needs and is in the best position to make the hard rational decisions on the volume and source of supplemental gas supplies it wishes to pursue. Therefore, the Federal Government, by approving LNG import projects which do not serve the actual requirements of natural gas utilities, would `e exercising unwarranted preemptive control over the decisions of individual utilities and state regulatory commissions.

Indeed, the best test of the particular regional or subregional market for an import is the degree to which gas distribution utilities will directly contract for the proffered gas supplies. Moreover, reliance on decisions by state-regulated entities whose utility obligations tie them directly to consumer and community needs will promote flexibility; whereas exercising Federal authority to impose the consequences of pipeline companies' LNG purchases on their customers tends to stifle competition.31/ Accordingly, ERA maintains a presumption in favor of directly committing imported LNG to state-regulated distribution companies or end-users, unless there is a clear, overriding national need shown for a different project structure.

Both of the LNG import cases previously decided by ERA, Pac Indonesia and Distrigas,32/ involve direct sales to distribution companies, which contracted to fulfill their own gas needs. In such cases, where we are merely asked to confirm a state-regulated utility's decision, there may be less reason for a rigorous examination of national or regional need for the gas.

Concerning the security of supply of a proposed import, we will consider not only whether the exporting country has ample reserves to meet the sales contract requirements, but also the degree to which LNG deliveries would be susceptible to natural, political or technical disruption, occurring within the country of origin, along the shipping route or at the receiving terminal.

In no event can ERA assure uninterrupted delivery of overseas fuels. Accordingly, the adequacy of the project sponsors' contingency plans to deal with any disruptions in the flow of gas to U.S.A. customers is a relevant factor. ERA will require the applicants in import projects to develop a contingency plan satisfactory to the FERC or state regulators, as the case may be.

In reviewing the import price of a proposed import to determine whether it is not inconsistent with the public interest, ERA has the responsibility to assess carefully the impact all the pricing provisions would have on our national energy goals as well as the extent to which the prices are justified in terms of national and regional needs. This involves balancing the long-term financial requirements of the project sponsors with the consumers need for a source of energy which is protected from unacceptable risks in price or availability.

ERA will consider whether the proposed price is in line with the equivalent energy costs of alternate supplies or whether there are cheaper sources of supply, including synthetic fuels or overland imports of natural gas. For example, in Pac Indonesia, ERA compared the proposed import price with various alternate fuel sources and found that,

> . . . due to limited flexibility in the California market to switch to other energy types because of its unique air quality problems, the delivered price of Indonesian LNG may be roughly equivalent to or even lower than the incremental cost of true alternate sources for residential space heating purposes, such as synthetic natural gas (SNG) from imported naphtha or, perhaps, electricity, available within the timeframe associated with this project.33/

In addition, ERA will consider whether the initial FOB price is arbitrarily inflated, and will ask whether the consumer would be exposed to unreasonable price increases under contract escalation clauses. In both the Pac Indonesia and the Distrigas cases, ERA has explicitly recognized that some price escalation provisions might be appropriate in LNG contracts between the exporting country and the importers. However, there is a presumption against escalation provisions tied directly and exclusively to world oil prices.

ERA has a responsibility to assess carefully whether there is an equitable distribution of risk between the project sponsors and consumers in terms of treating unexpected shipping and other costs and project failure. In approving imports ERA will strive to protect American consumers from unwarranted costs and risks.

ERA may consider how allowable costs will be passed on in determining whether an import is not inconsistent with the public interest. As was stated in Opinion No. One,

> In general, the DOE supports the concept of incremental pricing, while recognizing that there are genuine difficulties in implementing that concept . . . . the DOE will closely scrutinize pending projects to determine the extent to which an incremental pricing requirement will serve the public interest in each case. (Opinion No. One, pp. 34, 35.)

In this context the comments of the Council on Wage and Price Stability on the end-use pricing of gas imports are particularly relevant.

> . . . Requiring incremental pricing would be desirable in that it avoids loading significant project risks on the consumer and thus provides added incentive to the LNG company to negotiate acceptable contract terms.34/

LNG imports would provide an estimated 9 percent of total U.S.A. gas consumption by 1985 if all the applications currently pending are approved.35/ Moreover, the three pending projects would almost double the amount of imported LNG already approved. ERA, therefore, must carefully scrutinize each application to determine whether such rapid expansion of imports is desirable and that the terms and conditions are not inconsistent with the public interest.

E. Security of Supply

The supply security of a long-term LNG import project encompasses a number of inter-dependent factors:

The economic, political, and technical reliability of the exporter; and

The risk pertaining to the supply and delivery terms of the exporter's sales contract.

Over the 20-25 year life of this proposed project, the economic, political, and technical elements of reliability assume varying degrees of significance in response to changing energy markets, and technical and political considerations.

Political considerations relate to bilateral relations, including energy trade. Both the Departments of State and Defense expressed no objections to this import application (See Initial Decision). Algeria has been supplying LNG to U.S.A. energy markets for a number of years through the Distrigas project.36/

Algeria has large reserves of natural gas which appears on the record to be sufficient to fulfill the supply requirements of this project.37/ Algeria's proved gas reserves of nearly 100 Tcf, based on a 1977 DeGolyer & MacNaughton report for Sonatrach, are adequate to support cumulative (July 1976-December 2002) gas export, processing, and indigenous requirements.38/ Should all of Sonatrach's potential contracts come to fruition, Algeria's gas reserve position would be adequate but would leave little excess.39/ The closer a supplying country's reserves approach actual contractually committed delivery quantities, the greater the chance that a breakdown in any part of the supply process will result in actual delivery problems.

Algeria is a leader in exporting LNG and has been doing so for approximately 13 years. Sonatrach is experienced in the technology of producing liquefied natural gas for export, and is currently constructing support facilities which, in the aggregate, would be adequate to effect the liquefaction and delivery of gas to the cryogenic vessels as required for the TAPCO project and for its other contractual obligations.

U.S.A. gas consumers however, could be exposed under the cost-of-service tariff provisions requested by the Applicants if reductions or interruptions in delivery stemming from technical (facility) problems in the exporting country occur. This problem is further complicated by a broad force majeure provision (Article XIII) which encompasses factors not generally contained in such provisions.40/

LNG import projects of this scope and duration impose demands on both importer and seller; the importer must be assured of a ready market in which to deliver the expensive supplemental gas supply and the supplier must stand ready to dedicate supplies of gas and processing facilities with which to make timely and consistent deliveries. Algeria, through Sonatrach, has stated that it stands willing to dedicate the total of its national gas reserves and liquefaction and related facilities in support of many of its actual or proposed export ventures, including the TAPCO project, rather than dedicating specific reserves and support facilities to individual projects. Sonatrach has not dedicated any particular reserves or any specific liquefaction or other facilities to the TAPCO project.

In the Distrigas and El Paso I projects, however, Sonatrach did dedicate specific liquefaction facilities to each contract. In the Distrigas project, Sonatrach also agreed to allocate available gas from specific Skikda liquefaction units to Distrigas and another customer during periods of reduced delivery resulting from technical problems.41/ In the TAPCO case, however, should gas reservoirs not produce satisfactorily or should support facilities suffer periods of prolonged inoperability, Sonatrach may well be forced to allocate remaining uncommitted supplies or facilities among existing commitments (thus reducing deliveries to some contracts), to assign priorities to various deliveries (and thus not deliver to certain foreign customers) or to prorate available quantities (and thus deliver less than contracted volumes to each purchaser). Sonatrach does not warrant or guarantee the volumes it will deliver under the Tenneco LNG sales contract. If there are insufficient reserves, or technical failures impeding deliveries, ultimately it is the consumer who will suffer.

In connection with this application, TAPCO did not submit a contingency plan to protect high priority consumers from sudden supply interruptions which could occur during the five-month winter heating season. The Energy Resources Council testified as to the need for a contingency program to protect high priority consumers from interruptions during the winter heating season. However, in the initial decision the judge suggested that a contingency plan might be required one year prior to the proposed commencement of this project (Initial Decision, p. 70).

F. Need for the Gas

During the course of this proceeding the primary question of the need for the project gas supply was not given a thorough evaluation. The record does not address the issue of national or regional, as distinct from one pipeline system's, need for natural gas.42/ Rather the applicants' testimony, showing TGP's need for the additional gas supplies, comprised the bulk of the evidence presented in the record. Brooklyn Union did state that it had no present need for this gas, particularly at the sales price proposed by TAPCO, because of unique circumstances on its system, but did not question the general future need for the supply in the TGP system.

The evidence submitted by TAPCO alleges that the TGP system will experience a shortfall in meeting its gas utility customers' priority No. 1 and 243/ contract requirements by approximately 10.9 trillion cubic feet over the next twenty years. TGP states that without the gas from this project approximately one-third of the priority 1 entitlements in its service system will be curtailed by the winter of 1985-1986.44/ TGP further claims that even with the addition of the Algerian LNG it would still be unable to meet its customers' high priority requirements.

TAPCO states it included the impact on the TGP system requirements resulting from energy conservation efforts and conversion to alternate fuels by some low priority customers threatened with yearly curtailments in its assessment of the need for the gas, but was not specific as to quantity or how the impact was derived. It is possible that sizable additional quantities of low priority gas could be released for priority 1 and 2 users as a result of new or reemphasized conservation and conversion measures.

Nationally, residential and small commercial users, generally the highest priority users of gas for curtailment purposes, are expected to consume approximately 7 to 8 Tcf per year by 1985. Another 10 Tcf per year will be consumed by industry, both for energy purposes and as a chemical feedstock. The remaining supply of natural gas estimated to be from 2 to 3 Tcf per year will be consumed by large commercial users and for electrical generation, primarily intermediate and peak load generation. Of the industrial fuel consumption about 4 Tcf per year will be considered to be premium fuel use, i.e., process fuel, chemical feedstock and agricultural use. Thus, the total premium gas demand in 1985 is expected to be at a maximum of 12 Tcf per year, well within the total projected domestic supply level for that year of 19 to 20 Tcf per year.

A better approach to assessing regional need for the gas from this project would have been to focus on the collective needs of the local gas distributors who are the intended purchasers of TGP's incremental supply. TGP's customers were not asked until oral argument if they will need this gas in the mid-1980's. When this concept was broached in the notice of oral argument, TAPCO undertook a survey of TGP's 20 high volume customers (representing 90 percent of TGP's system sales) to determine the volume, if any, of TAPCO LNG each customer would be willing to presently purchase at an incremental cost of up to $6.00 per Mcf for delivery in 1985. The contract would contain take or pay provisions and a minimum bill provision which would make the customer liable for its proportionate share of project operations and maintenance costs, debt service and equity investment in the event of project failure. Once the proposal was fully explained, none of TGP's customers were willing to make such a commitment at this time. The primary reason cited was that each customer had doubts as to the competitiveness of $6.00 per Mcf gas with alternative fuels. Other reasons, such as the lack of an irrevocable assurance that this supply would be firm, uncurtailable and not subject to redirection, were also given.

G. Purchasers and Participants

In evaluating LNE import proposals, DOE applies a presumption that any LNG import scheme should enable distribution utilities individually to determine in cooperation with state regulatory agencies their requirements if any for supplemental natural gas supplies. The utilities would then have the option to either develop their own sources of supply or contract directly with LNG importers for specific volumes to be delivered directly to their system. That presumption has been satisfied in all LNG imports approved by DOE.

In Pac Indonesia, Opinion Number One, the Administrator conditionally approved a project in which the importer will sell LNG directly to two natural gas distribution utilities. These utilities contracted for Indonesian LNG after making the determination that this source of gas would satisfy their needs. Distrigas and its affiliate, DOMAC, were granted permission by DOE to sell LNG to ten (10) natural gas distribution utilities in the Northeastern part of the U.S.A. after each utility determined its own specific need.

The natural gas that TAPCO proposes to import into the U.S.A., on the other hand, would be sold to TGP an affiliate of Tenneco, which would in turn roll-in the volumes of LNG as part of its base supply. This gas would be sold by TGP to meet its contract commitment of deliveries to other affiliated and nonaffiliated pipeline companies and to natural gas distribution utilities for final delivery to the end-user. In no instance would TAPCO be selling any of the LNG in specific contracted for quantities directly to the natural gas distribution companies that serve the ultimate user of the gas.

The instant case record offers only a situation of construed demand, whereby a pipeline company derives its demand from the contractual obligations to natural gas distributors, who in turn must meet the needs of end-users. TGP in effect is attempting to determine and project the needs of its customers (pipeline and natural gas distribution utilities) for the next 20 years. From the perspective of an interstate pipeline company, such projections are a part of doing business.

The approach which DOE favors imposes on natural gas distribution utilities the risks and responsibilities of choosing from a diversity of supplies instead of imposing on them high-cost, long-term foreign LNG supplemental gas supply. By making each utility free to contract for its own high cost foreign supplies, competitive forces should operate more effectively. Here, there is no overriding national interest preventing each distributor served by TGP from determining what supplemental supplies, such as LNG, if any, to purchase and thereby stimulate.

H. Import Price

The import price subject to review in this application would be the U.S.A.-Canadian border price for regasified and transshipped Algerian LNG. This price represents an aggregation of the Algerian FOB sales price, the ocean freight rate, and the Canadian regasification and pipeline cost element.

In the initial decision the administrative law judge estimated a border price during the first year of regular delivery, 1983, of $3.97 per MMBtu.45/ The proposed import price is significant given its initial level and the relative lack of United States control over the operations and costs of the nonjurisdictional components during the life of the project.

Tenneco LNG is seeking to sell the gas to TAPCO at the U.S.A.-Canadian border under a cost-of-service tariff which would automatically flow through all cost elements over the life of the project. U.S.A. control would be limited to after the fact auditing of the maritime and regasification and transmission cost elements.

1. FOB Base Price

The base price for LNG to be sold to Tenneco is $1.30 per MMBtu FOB Algeria as of July 1, 1975. Sonatrach derived this price by taking an equally weighted combination of the daily prices for No. 2 home heating oil and No. 6 low sulfur fuel oil in New York Harbor as listed in Platt's Oilgram Price Service for the period January-June 1975. Estimated LNG transportation charges between Algeria and New York Harbor and terminalling charges in the latter were then deducted to derive the $1.30 per MMBtu base price.46/

The calculation of the base price is significant for two reasons. First, Sonatrach adopted this price scheme to establish the initial value of its product. Second, and more important, the method of commodity-based rather than cost-based valuation of the FOB LNG price is also used directly as the basis for future price escalation over the life of this long-term 20-25 year project. It is notable that increases in the estimated ocean freight rates are unlikely to be absorbed in the FOB sales price. Hence, cost overruns associated with the seaborne transportation charges may result in a delivered price which is higher than the comparable cost of competing petroleum products.

2. Contract Sales Price

The contract sales price at which the LNG is actually sold would be the higher of the base price plus escalation formula or the minimum sales price (i.e., floor price). The base price of $1.30 per MMBtu is subject to semiannual escalation, from July 1975, based on charges in the price for No. 2 and No. 6 oils in New York Harbor (Article VIII, 1 and 2). The formula is based upon an equally weighted combination of the highest average of the daily range of prices for No. 2 heating oil and 50 percent of the average daily range of prices for No. 6 low sulfur fuel oil. The specific price quotation mechanism is contained in Platt's Oilgram Price Service. Daily postings under the heading "South and East Terminals, New York Harbor District," are used to calculate the average of the highest No. 2 oil prices. The "Atlantic and Gulf Coast Resid, New York Harbor District, No. 6 Fuel," heading reflects average changes in the average price of No. 6 fuel oil. Under the Sonatrach contract, the escalator is applied twice yearly, in January and July. Since July 1975, we estimate that the escalator has added about $0.20 per MMBtu to the base price.

In the initial decision, the administrative law judge briefly addressed the FPC Staff's objections to the Sonatrach price escalator formula. The Staff requested that the Commission require prior approval of cost flow throughs when the prices of imported fuel oil, the basis of the Sonatrach escalator, increase at a faster rate than the consumer price index. The judge dismissed Staff's objections and found the Sonatrach-Tenneco LNG escalator formula to be consistent with the public interest.47/

The Sonatrach price escalator can be compared to the conclusions reached in DOE/ERA Opinions No. 1 and No. 2. In Opinion No. 1, DOE disapproved the Pacific Indonesia price escalator provision (based 50 percent on Indonesian crude oil prices and 50 percent on the BLS Wholesale Price Index--Fuels and Related Products) on the grounds that it was linked too directly to future movements in world petroleum prices. DOE also determined that the BLS fuels element would be influenced by future domestic energy pricing policy and by the price of the import itself, thus creating a self-compounding effect. DOE did not object, however, to the concept of a price escalator and suggested, alternatively, the use of a broad-based economic index.

The parties responded to DOE Opinion No. 1 by submitting a revised price escalator formula which was linked 50 percent to changes in Indonesian crude oil prices and 50 percent to changes in the BLS Wholesale price Index-All Commodities. The crude oil element of this formula contains a 15 percent limitation on annual price fluctuations. Any increase above the 15 percent annual limitation and any downward adjustment in excess of 15 percent are to be carried forward and applied in future years to the extent permitted by the ceiling or the floor. While DOE approved this formula, it did so only in relation to the specific circumstances of that case, and it is not to be considered a model escalator formula upon which future applicants should rely.

The Sonatrach formula used to establish the initial FOB price and subsequent escalation is linked entirely to future world oil price movements. World petroleum prices however, are administered prices, established by agreement among producer countries belonging to OPEC. The specific price quotation mechanism used in conjunction with Sonatrach's escalator tracks daily changes based on posted prices (as opposed to actual average transaction prices) in New York Harbor. The automatic Sonatrach escalator formula also lacks safeguards to protect U.S.A. consumers from the impact of future sudden and drastic increases in world oil prices.

The use of the Platt's Oilgram posted prices as proposed in this contract involves wholesale price quotations for small dealer tankwagon lots as opposed to more representative cargo lots. The tankwagon lots tend to reflect higher marginal prices and not the lower average prices which prevail in sales of large quantities. In instances where actual sales are discounted from the wholesale posted price quotations, the consumer may not receive the benefit of the lower actual sales price. Moreover, the use of the average of the highest daily prices for No. 2 oil will raise and maintain this price element at its highest daily levels. On the other hand, this contractual provision limits Sonatrach's exposure to the gas consumer's ability to benefit from lower sales prices for No. 2 oil.

The fuel indices used in the Sonatrach price escalator are premium petroleum products.48/ These products are generally processed from premium high gravity, low sulfur crude oils which are more expensive and less plentiful than other internationally traded crudes.49/ The U.S.A. already absorbs a large proportion of Free World sweet crudes. A future tightening in the availability of these low-sulfur crudes combined with shortages in worldwide refinery desulfurization and product upgrading capacity could exert an additional upward pressure on the Platt's price quotations. These potential developments could confer upon Sonatrach possible benefits which go beyond the intended purpose of an escalator clause designed to maintain LNG pricing at parity with competing petroleum fuels.

The Sonatrach contract includes a price renegotiation provision (Article XXIV) which requires the parties to meet the year after first regular delivery and every four years thereafter to review the FOB sales price. The purpose of this review is to ascertain whether the prevailing contract sales price is competitive with the market for imported natural gas and other forms of energy which are imported into the U.S.A. East Coast on a long-term basis. It would appear that adjustment to the FOB sales price mechanism could be made at that time, thus further placing consumers at risk.

3. Minimum Sales Price

The Sonatrach sales contract also contains a minimum sales price (Article VIII, 3) which is designed to protect the seller against sudden and rapid declines in the invoice price. This price is calculated on a monthly basis. The actual minimum sales price, $1.30 per MMBtu as of July 1975, is the sum of the initial minimum sales price plus a currency adjustor formula. The latter tracks the relationship between the dollar and a basket of six European currencies.50/

Whenever the U.S.A. dollar changes one percent (or more) from its initial July 1975 value against the basket of European currencies, the minimum sales price is adjusted. The minimum sales price can decline through the working of the currency adjustor, but can never fall below the base minimum sales price of $1.30 per MMBtu. (Article VIII, 3(c).) As of October 1978 we estimate that the operation of this formula has increased the minimum sales price by $0.16 per MMBtu.

This currency adjustor differs from the currency formula approved in DOE Opinion No. 2 in a number of regards. First, the Pertamina adjustor included a

25 percent life-of-the-contract ceiling on the maximum allowable increase stemming from the possible decline of the dollar against a basket of foreign currencies. The Sonatrach adjustor lacks a cap on the maximum increase permitted over the life of the contract. Further, the Sonatrach currency adjustor is calculated from July 1, 1975 while the Indonesian formula is calculated from the date of the initial delivery. On the other hand, the Pertamina adjustor is applied to the contract sales price rather than the minimum sales price.

4. Other Contract Provisions

Article VII of the Sonatrach sales agreement requires that quantities paid for but not taken in a given contract year can be made up without additional payment if the following conditions are met: (1) make-up must occur within the four subsequent contract years; (2) buyer must first have taken the contracted-for quantity for the contract year during which it has requested as make-up; (3) each of the annual deliveries requested as make-up is guaranteed only to the extent that it does not exceed 5 percent of annual contract quantity for the year in which failure occurred; and (4) aggregate make-up of any contract quantity is guaranteed only to the extent that it does not exceed 5 percent of annual contract quantity in that year. Moreover, "Quantities paid for and not taken by make-up in accordance with the preceding conditions are irrevocably lost to the Buyer and shall not be subject to subsequent make-up." (Article VII, Section 4). Moreover, the buyer is unable to request make-up beyond the term of this contract as specified in Article III of the Sales Contract. If certain quantities are not taken by the buyer because of an insufficient offering by seller, buyer promises to facilitate the taking of such quantities during the performance of the contract, to the extent its facilities and its tankers permit. However, there are no penalties or countervailing responsibilities on Sonatrach if it underdelivers the contracted-for quantities.

The Pacific Indonesia contract provides more symmetrical and countervailing purchase and sales responsibilities for buyer and seller than are found in TAPCM's contract. The Pacific Indonesia contract contains a life-of-contract time allowance for the buyer to make-up liftings paid for but not taken. In addition, if Pertamina fails to deliver at least 90 percent of contract requirements and fails to make up those quantities, Pac Indonesia may terminate the contract or require Pertamina to deliver a quantity equivalent to that not delivered previously, at a 10 percent discount from the sales price (Article 7.7, Pertamina Sales Contract).

5. Shipping Costs

The cost of transporting the LNG from Algeria to the proposed terminal at Tiner Point, New Brunswick would constitute a significant portion of the

U.S.A.-Canadian border price. TAPCO estimates that the shipping cost will add $1.07 per MMBtu, in 1983 dollars, to the U.S.A.-Canadian border price. This estimate assumes four tankers would be owned by a U.S.A. shipper and four would be owned by Sonatrach.

In the Initial Decision the judge noted that TAPCO had not submitted a finalized shipping agreement for the four tankers to be provided by Sonatrach. 51/ However, the Judge approved a TAPCM shipping agreement that would be substantially identical to a shipping agreement between Sonatrach and El Paso Eastern Company. (El Paso Eastern, et al., FPC Docket No. CP77-330 et al., ERA Docket No. 77-006-LNG.)

The freight rate applicable to the Sonatrach vessels calls for two formulas, one a "Freight-Rate" formula and the other an "Additional Freight" formula. The "Freight Rate" formula is designed to recover Sonatrach's capital investment in each vessel, debt service, return of, and on, equity capital and taxes. The freight rate incorporates an after-tax rate of return of 19 percent on equity capital which is inclusive of a 50 percent Algerian income tax rate. In addition to the freight rate, Tenneco LNG would reimburse Sonatrach for all reasonable ship-operating expenses on a monthly basis.

The "Additional Freight" (which constitutes a minimum bill) calls for payments to Sonatrach in the event the freight rate on LNG shipments is not sufficient to cover debt service charges and return of equity, but not return on equity. The additional freight provision requires application of a currency adjustment factor. In the event that Sonatrach claims force majeure, these additional freight payments would cease.

The details of the shipping contracts covering the four ships to be provided by Tenneco have not been finalized. However, the basic framework of an agreement between Gas Ships and the SVI-partnership was considered in the Initial Decision. It was noted that all major cost components incurred in providing these ships will involve Tenneco subsidiaries. Judge Litt has described the potential compounding effect of these cost components:

> Tenneco will earn a profit, at an unknown rate, on the construction of the ships at Newport News (Tr. 3333-3334). That profit will then constitute part of the total capital cost payable by SVI for the ships which are to be financed 16.2% with Tenneco equity. That total capital cost will be reflected in the total capital investment underlying the demise charters which contain charter hire rates reflecting an 18% return on equity, at least 50% of which will flow back to Tenneco. Gas Ships will incur certain additional capital costs, and to the extent equity funds are employed to cover these costs, Tenneco will earn 18% on that equity. (ID, p. 105.)

Freight expenses are the second largest cost component of the regasified LNG at the U.S.A. border. Tenneco's ill-defined arrangements fail to give DOE an adequate basis for evaluating costs or judging their reasonableness. In light of applicants repeated insistence on the need for an expedited decision from the DPC, FERC and ERA, it is noteworthy that to this very date applicants have not provided DOE with a finalized shipping contract for their own ships.

6. Canada

All previous LNG import applications submitted to the U.S. Government have involved receiving and regasification terminals located in the U.S.A. The TAPCO project differs in that all of the major cost components including the receiving and regasification terminal, are beyond DOE jurisdiction. The consumers of the gas from this proposed project are faced with long-term acceptance of the natural gas stream at the U.S.A.-Canadian border with all of the complex, high cost facilities required to receive the LNG residing outside U.S.A. jurisdiction. Under the applicants proposal, the only control the U.S.A. would have over any aspect of the border price throughout the life of this 20-year contract is in approving or disapproving the import application. All of the costs incurred externally, including the regasification and transmission cost element, would be passed on automatically to U.S.A. consumers at the international boundary. Unlike this proposal, the existing overland gas trade between Canada and the U.S.A. involves border purchases with relatively modest processing and transmission charges.

7. Cost-of-Service Tariff

The applicants have proposed to flow through to TAPCO all project costs via the sale of gas by Tenneco LNG to TAPCO at the U.S.A.-Canadian border. TAPCO will pay Tenneco LNG for all expenses incurred, including but not limited to the price of the LNG FOB Algeria, shipping, terminalling, and regasification and transportation to the U.Q.A. border. TAPCO then proposes to flow through to TGP via a cost-of-service tariff, its purchase gas cost and transmission charges. Finally, TGP is seeking permission before FERC to revise its present purchase gas adjustment clause (PGAC) to permit the flow through to its customers of the TAPCO supply costs under its normal PGAC filings. TGP would then roll in the cost of TAPCO gas with other supplies and the gas would be sold under its existing rate structure.

The applicants claim that full flow through of all costs is necessary in order to obtain project financing. The applicants have proposed not to use the credit strength of Tenneco but rather to raise the necessary capital through project financing using only project revenue to recover equity and returns thereon. Furthermore, TAPCO proposes to use debt financing to the maximum extent possible, thus greatly limiting Tenneco's need to raise equity capital and at the same time reducing its level of risk. According to TAPCO, the consumers will benefit from a substantial saving due to reduced return on equity and to the tax savings attributable to debt service payments.

The cost flow through proposals that have been presented by TAPCO as essential elements of this project, if approved, would seem to reduce Tenneco's risk to the lowest possible level for a project of this size. Continuous delivery of even a small fraction of the proposed volumes would enable Tenneco to recover its equity plus a return on equity.52/ Thus, the financial risks normally borne by entrepreneurs would be shifted to the consumers.

The rate of return on an investment should reflect the level of risk assumed by the investor. Yet, TAPCO has requested rates of return on Tenneco's investment ranging from 16 to 18 percent, even though only total project failure would place its return on equity at risk.

Both FPC Staff and the State of New York challenged the applicant's cost flow through proposals. Specifically, they took strong issue with TAPCO's proposed "all events" cost-of-service form of tariff and TGP's proposed revision to its PGAC. They recommend instead that TAPCO be required to file an initial straight volumetric rate, with a minimum bill provision similar to that permitted in Trunkline, sufficient to recover TAPCO's average costs incurred during a three-year developmental period, followed by a superseding volumetric rate reflecting full contract deliveries (ID, p. 86). Judge Litt concluded that:

> . . . the TAPCO tariff shall reflect a straight volumetric initial rate, with a minimum bill provision applicable during periods of severe interruption in the form adopted by the Commission in Trunkline LNG. (ID, p. 89.)

8. Project Failure and Non-Completion

The record contains few references to the possibility of project failure and how to deal with recovering costs incurred. The Administrative Law Judge concluded that in the event of a cessation in service a special hearing would be convened to determine on what terms TAPCO would be permitted to recover its project costs.53/

I. Balance of Payments

The balance of payments impact of this project was not considered in the record nor discussed in the Initial Decision. The issue, however, was raised as part of the oral argument held by ERA in New York on July 18, 1978,54/ and is required to be reviewed by DOE Delegation Order No. 0204-25.

The siting of the LNG terminal in Canada is significant from the standpoint of U.S.A. balance of payments considerations. In supplemental comments concerning the matters raised during the oral argument, Tenneco submitted data indicating that the balance of payments outflow associated with siting the receiving terminal in Canada rather than the U.S.A. amounts to $41.8 million per year, or $836 million over the life of the project.55/ This estimate, however, does not measure the U.S.A. jobs and related economic benefits foregone by the siting of a terminal in another country.

LNG imports differ from oil imports in that the former involve a long-term commitment to purchase gas. Moreover, the long lead times and potential for cost overruns on the shipping and liquefaction components make it difficult to measure whether LNG will be competitive with or more expensive than liquid fuels over the life of an LNG contract.

Moreover, the proposition that this large LNG import will necessarily back off crude oil or petroleum products throughout the life of the project remains to be established, particularly in view of the new prospect for added gaseous fuel supplies without so large or rapid an increase in dependence on remote LNG sources.

Conclusion

We have reviewed the facts of the TAPCO import proposal against the statutory requirements of the Natural Gas Act, ERA's delegation of authority, and national energy policy. We find that, on balance, the application to import LNG into the U.S.A. via the New Brunswick terminal does not now meet the statutory test that it is "not inconsistent with the public interest."

In reaching our conclusion we have particularly weighed the following factors. The project fails to satisfy ERA's presumption in favor of direct LNG sales to distribution utilities. As the applicants have structured the project, none of the gas would be sold directly to such utilities. Applicants have not demonstrated the reason why the public interest requires such a project at this time.

Within the specific circumstances of this case, the applicants have not now demonstrated a national or regional need for this gas. The applicants relied on their contract demand, as distinguished from the end-use requirements of customers of gas distribution utilities, to determine their long-term natural gas needs. We are not convinced that the pipeline's requirements necessarily reflect a real need, and the unwillingness of TGP's customer distribution companies to commit themselves to purchasing the LNG directly reinforces our doubt.

Moreover, we must take full account of proximate supply opportunities before sharply increasing U.S.A. dependence on LNG imports. For the short term, the U.S.A. natural gas industry enjoys substantial supply deliverability to meet residential, commercial and industrial needs. Unification of the interstate and intrastate markets by the NEA legislation makes the deliverability more readily available. For the longer term which the applicants address in the proposed project, we also anticipate substantial domestic prospects. These include the potential for additional supplies from the lower 48 states, including the Baltimore Canyon Trough and other portions of the continental shelf, from the Alaskan North Slope and other domestic frontier and synthetic sources, and from proximate overland foreign supplies. The NEA legislation offers the potential to expand overall national supplies and shift supplies more evenly to interstate markets. This new legislation further reduces the need for rapid expansion of LNG imports even as a hedge against failure to develop new, long-term gas supplies near at hand.

Although the project would account for over a quarter of TGP's future gas supplies, applicants have failed to propose a contingency plan to protect their customers from interruptions during the winter heating season. There is no convincing showing why these LNG project sponsors should be excused from including as an integral part of this project a contingency plan, covering possible interruptions of consumers' supply, for appropriate public review.

The automatic FOB price escalator formula in the Sonatrach-Tenneco LNG sales contract is linked entirely to future changes in world petroleum prices. The formula also lacks safeguards to protect U.S.A. consumers from the impact of future sudden and drastic increases in world oil prices. The specific price quotation indices--the daily prices for No. 2 and No. 6 heating and fuel oils respectively in New York Harbor--are based on posted prices rather than actual weighted average transaction prices. In instances where actual sales prices are discounted from the daily price postings, the consumers may not receive the benefit of a lower actual sales price. Moreover, the existence of a price renegotiation clause and the lack of symmetry with respect to the delivery terms increase U.S.A. consumer exposure without providing any reciprocal benefits.

We recognize that denial of this particular application may result in Sonatrach selling some or all of the gas which was originally dedicated to this project to proximate European markets. However, we cannot conclude that this large, long-term commitment to a LNG project is now needed. Our denial is without prejudice to any future evolution of mutually beneficial opportunities for international gas trade.

Order

The Department of Energy orders:

Pursuant to Section 3 of the Natural Gas Act and Delegation Order No.

0204-25, the applications, as amended, of Tennessee Atlantic Pipeline Company, Inc. (TAPCO), and Tennessee Gas Transmission Company, Inc. (collectively "Applicants"), for an order (a) authorizing importation into the United States by TAPCO of LNG from Algeria for a 20-year period as described in FPC Docket No. CP 77-101; and (b) authorizing, pursuant to Executive Order 10485, construction of certain facilities on the United States-Canada border near Calais, Maine, as applied for in FPC Docket No. CP 77-102; are hereby denied.

Issued in Washington, D.C., December 18, 1978.

--Footnotes--

1/ All TAPCO's costs are in terms of the year of their incurrence. The $3.97 delivered cost is comprised of a LNG FOB cost of $2.39, $1.07 shipping cost, $0.47 terminal and vaporization cost, and $0.04 Canadian transportation. TAPCO derived the $2.39/MMBtu FOB Algeria price as it appears in the record by escalating the No. 2 and No. 6 fuel price by 1 percent per year in real terms for the period 1976-1980 and 5 percent per year for the period 1980-1983, and applying these derived prices to the base price of $1.30 per MMBtu as of July 1, 1975. Operating costs were inflated at 6 percent and capital costs at 7 percent.

Calculating the operation of the contract FOB escalator, using actual Platt's data, shows the FOB Algeria price to be about $1.50 per MMBtu as of July 1, 1978.

2/ National Energy Board, "Reasons for Decision in the matter of the applicants under the National Energy Board Act of Tenneco LNG, Inc. Canadian Lowell Gas Ltd., TransCanada Pipeline (New Brunswick) Limited, and Lorneterm LNG Limited;" November 1977.

3/ Ibid, Appendix 1, Terms and Conditions of Import License for Liquefied Natural Gas (LNG), p. 2, item 7.

4/ Distrigas of Massachusetts Corporation, et al., FPC Docket No. CP70-216, et al., ERA Docket No. 77-007-LNG.

5/ 42 FR 40776, November 29, 1977. The original delegation has been modified, Delegation Order No. 0204-25, 43 FR 47769, October 17, 1978.

6/ See 43 FR 26609, June 21, 1978.

7/ See 43 FR 33870, August 1, 1978.

8/ FPC Order 467B (38 FR 6384, March 9, 1973). FPC priority of service category 1 includes residential service and small commercial use of less than 50 Mcf on a peak day. Priority of service category 2 includes (1) large commercial use (over 50 Mcf per peak day); (2) firm industrial plant protection requirements; (3) firm industrial feedstock use; (4) firm industrial process use; (5) firm industrial use by customers whose aggregate industrial use is 300 or less Mcf/d; and (6) storage injection.

9/ I.D., p. 72. In a footnote, the ALJ added "The ease of disposing of the surplus would be further enhanced under rolled-in pricing.

10/ FPC Docket No. CP74-160 et al., Initial Decision on Importation of Liquefied Natural Gas from Indonesia, Administrative Law Judge Samuel Z. Gordon, July 22, 1977.

11/ November 21, Public Service Commission of the State of New York; November 21, State of Maine; November 22, TAPCO and Tennessee Gas Pipeline Co.; November 22, Commission staff; November 22, TransCanada (New Brunswick) Ltd. and TransCanada Pipelines; November 05, Central Maine Power Co.; November 25, Natural Resources Council of Maine, et al.; November 22, Motion of Council on Wage and Price Stability to receive brief on exceptions and late file petition for limited intervention, request for intervention, and Brief on Exceptions; December 1, TAPCO and Tennessee Gas Pipeline Co.; December 5, Rhode Island Division of Public Utilities and Carriers; December 7, TAPCO and Tennessee Gas Pipeline Co.; December 7, Public Service Commission of the State of New York; December 7, TransCanada (New Brunswick) Ltd. and TransCanada Pipeline Ltd.; December 7, Rhode Island Division of Public Utilities and Carriers; December 7, General Motors Corporation; December 7, Columbia Gas Transmission Corporation; December 7, Commission Staff; December 28, Natural Resources Council of Maine.

12/ See Footnote 6, p. 9.

13/ July 7, Distrigas Corporation; July 14, Tenneco Atlantic Pipeline Company and Tennessee Gas Pipeline Company; July 19, Council on Wage and Price Stability; July 26, State of Connecticut, Public Utilities Control Authority; July 27, Pennsylvania Gas and Water Company; August 8, Northern Illinois Gas Company; August 8, Conservation Council of New Brunswick--Saint John Branch; August 9, Northern Indiana Public Service Company; August 18, Columbia Gas Transmission Corporation; August 18, Columbia LNG Corporation; August 18, Tenneco Atlantic Pipeline Company and Tennessee Gas Pipeline Company; August 18, TransCanada Pipelines (New Brunswick) Limited9 August 18, Process Gas Consumers Group; August 18, Phillips Petroleum Company; August 18, FERC Staff; August 18, Central Maine Power Company and Maine Electric Power Company, Inc.; August 22, Natural Resources Council of Maine; August 22, Fair Environmental Deals for United People; August 23, Brooklyn Union Gas Company.

14/ Notice of Oral Argument, 43 FR 26610, June 21, 1978, Question 4(b).

15/ Applicants' "Background Material" relating to ERA notice of Oral Argument, July 14, 1978, Section 4(b), p. 2.

16/ The DOE estimates represent first year costs while the above TAPCO estimate for its LNG import represented third year costs. Additionally, DOE estimates included a local distribution charge of about $1.00 per MMBtu whereas TAPCO's estimate of these charges was $0.25 per MMBtu.

It should be noted here that the news release from which applicants obtained the DOE estimates also provided an estimate for "Imported LNG" of $7.95 to $8.67 per MMBtu.

While DOE's costs estimates are not comparable to specific projects and are indexed to a $20 per barrel oil price, they are appropriate for comparison of the DOE supplemental gas cost estimates in the press release.

However, we cannot reconcile the $5.59 estimate with the highest price quoted in the survey of TGP's largest customers ($6 per Mcf in 1985).

17/ DOE Delegation Order 0204-4; 42 FR 50726, November 29, 1977.

18/ DOE Delegation Order Nos. 0204-25 and 0204-26; 43 FR 47769, October 17, 1978. Delegation Order No. 0204-25, addressed to ERA, amends Delegation Order No. 0204-4.

19/ The Delegation Orders also apply to exports of natural gas; however, those provisions are not applicable to this case.

20/ Site-specific environmental and safety issues are assigned to FERC. Nonetheless, ERA will have to comply with the requirements of the NEPA, and we plan to coordinate the development of necessary environmental impact statements with other Federal Agencies, including the FERC.

21/ Sections 201, 203 and 204 of the NGPA require that any first sale acquisition costs of certain future LNG imports, which exceed the incremental pricing threshold applicable for the month in which the LNG enters the U.S.A. and which are incurred by interstate pipelines or by local distribution utilities which purchase imported LNG directly, be automatically passed through to industrial users. Section 207 of the NGPA allows DOE the discretion to apply those passthrough requirements to certain transitional import applications, including the TAPCO proposal. In the case of the Alaskan Natural Gas Transportation System, however, Section 208 of the NGPA provides for rolled in pricing for most costs to be incurred.

22/ The division of authority set out in the recent ERA and FERC delegations applies to all natural gas import applications currently pending before either agency, with certain exceptions which do not apply here. This includes all applications initially submitted to ERA on or after October 1, 1977, or which were transferred to the Secretary of ERA pursuant to the final rule dated October 1, 1977 (42 FR 55534, October 17, 1977), after completion of certain procedures by the FERC. This latter category includes the TAPCO application.

23/ DOE/ERA Opinion No. One, Opinion and Order on Importation of Liquefied Natural Gas from Indonesia, ERA Docket No. 77-001-LNG, December 30, 1977, p. 4.

24/Opinion No. One, pp. 4,5.

25/ DOE/ERA Opinion No. Two, Opinion on Rehearing, Pacific Indonesia LNG Company and Western LNG Terminal Associates, ERA Docket No. 77-001-LNG, September 29, 1978, pp. 5,6.

26/ Alaskan Natural Gas Transportation Act of 1976 (Pub. L. 94-586) and H.R.J. RES. 621, Pub. L. No. 95-158, 91 Stat. 1268, 95th Cong., 1st Sess. (1977).

27/ Conference report to accompany HR 5289, Sen. Report No. 95-1126, p. 103.

28/ The Congress similarly encouraged the development of the interstate U.S.A. natural gas industry by passage of the NGA. When the domestic pipeline infrastructures were being constructed, exercise of Federal authority under the NGA conferred certificates of public convenience and necessity, eminent domain to acquire rights-of-way, rolling-in of all incremental costs, a tariff system that compelled each local gas distribution utility customer to share in the costs of each increment of capacity of interstate pipeline, pooling of risks among many consumers including risk of malfunction or destruction of loop pipelines or pump stations, long-term contractual commitments and restrictions on abandonment by sellers or buyers. This exercise of Federal power helped encourage the creation of vast assets in the U.S.A. energy economy. The very existence of this infrastructure now makes the U.S.A. market an attractive outlet for new gas supplies.

29/ Because of the many variables which must be considered in estimating natural gas supply, such as projections of the quality of the undiscovered resource base, finding ratios per foot of wells drilled, reserve-to-production ratios, drilling costs, the opportunity cost of capital, and expansion capability of the industry, supply response estimates have varied over a wide range. Independent studies estimating the incremental supply of natural gas due to become available after implementation of the NGPA range from .7 Tcf to 5 Tcf in 1985, as follows:

	1985 (in TCF)	Cumulative (1978-1985) (in TCF)
Independent Gas Producers Committee	5.0	.....
American Gas Association	2.3	.....
Draft Economic Analysis of House Conferees	up to 1.4	12
Energy Information Administration	1.0	6.0
Congressional Budget Office	.7 to .8	n/a

30/ The holding in State of North Carolina, et al. v. FERC et al., F.2d (D.C. Cir., 1978), may imply that ERA must consider actual end-users, rather than total pipeline markets and constructive end-uses.

31/ The decisions on need for expensive imported LNG should be dispersed as much as possible to the boardrooms of distribution companies, which, in many instances, are local utilities with the obligation of meeting actual consumers' demands for natural gas. Pipelines, on the other hand, are only obligated to meet contractual requirements and are at least one step removed from the decision making centers. Decentralization of LNG purchasing decisions results in less Federal regulation over the use of supplemental supplies of natural gas and promotes more competitiveness in the use of alternate sources.

32/ DOE/ERA Order on Importation of Liquefied Natural Gas from Algeria, ERA Docket No. 77-011-LNG, December 31, 1977.

33/ Opinion No. One, p. 6.

34/ We note that cushioning the impact of high-priced foreign gas supplies on domestic consumers through rolled-in pricing could have an inflationary impact on the terms under which other gas importing nations acquire imported gas supplies.

35/ Approved

El Paso I (Algeria).............388 Tcf/yr

Trunkline (Algeria).............179Tcf/yr

Distrigas (Algeria).............044 Tcf/yr

Pacific Indonesia (Indonesia)....226 Tcf/yr

.837 Tcf/yr

Pending

TAPCO (Algeria)..................360 Tcf/yr

El Paso II (Algeria).............337 Tcf/yr

Columbia/Consolidated (Iran).....109 Tcf/yr

.806 Tcf/yr

Total..........................1,643 Tcf/yr

The Pacific Indonesia proposal has been conditionally approved subject to the opinion on rehearing on certain economic issues and the final selection of a site for a receiving terminal in California.

36/ Except for technical problems which forced the shut-down of the Skikda liquefaction plant during the later part of 1973 and all of 1974, Algeria has been continuously delivering LNG to U.S.A. markets since 1970. This past spring the El Paso I project began initial LNG deliveries into Cove Point, Maryland.

37/ We note that no participant in the proceeding challenged either the gas reserve or deliverability presentation of Sonatrach or TAPCO.

38/ Testimony of James W. Watson, Joint Hearings on Distrigas and TAPCO LNG Projects, Transcripts II and III, and Exhibit #89. This estimate is based on proved reserves in Algeria's four largest gas fields.

39/ As TAPCO has asserted, Sonatrach has alternative options for marketing gas in nearby Europe via LNG projects. ERA is aware that since the Initial Decision Sonatrach has continued to attempt, with some success, to sell additional gas in Europe. It had concluded contracts with two West German power distributors and Swedegas for the annual sale of about 0.21 Tcf of gas or about 5.0 Tcf over a twenty-year period (including gas used in the liquefaction process). Sonatrach and the Italian state energy company Ente Nazionale Idrocarburi (ENI) are constructing an undersea, Trans-Mediterranean pipeline to deliver Algerian gas to Sicily and then on to Italy. The completion of this project will provide Sonatrach with an additional delivery system through which to move gas to nearby European markets.

40/ The force majeure provision includes assimilated circumstances involving:

Serious accidental damage to operations or equipment affecting the natural gas production facilities at the wellhead, transportation by pipeline in Algeria, treatment, liquefaction, storage, loading operations, transportation by tankers, unloading, storage, and regasification. . . ,

. . . Act of a third party affecting the same items specified above, ...

41/ Distrigas shall have a 12 percent interest in production from lines 1, 2, and 3 and a "first call" on production from line 4. Initial FERC Decision on Distrigas Project, November 18, 1978, page 3.

42/ DOE Delegation Order 0204-25 requires that ERA consider the national need for the natural gas to be imported, and allows DOE to consider, as appropriate, the regional need. DOE in Pac Indonesia, Opinion One, examined the regional need for gas within the State of California.

43/ See Footnote 8, p. 9.

44/ TGP estimates that over the life of this project (20 years) it will need about 23.56 trillion cubic feet of natural gas to meet the requirements of priorities 1 and 2. TGP estimates it has 9 trillion cubic feet of committed reserves and 3.60 trillion cubic feet of future reserve additions from traditional supply sources leaving a shortage of 10.9 trillion cubic feet.

45/ The administrative law judge's estimate of the border price (Initial Decision, p. 4) is derived from TAPCO's Initial Brief, Appendix A. The estimated $3.97 per MMBtu (in 1983 dollars) border price includes a $0.39 FOB Algeria cost component, a $1.07 shipping rate, and $0.51 regasification and transmission charge.

46/ After deducting estimated liquefaction and other Algerian land-based costs, DOE estimates that the wellhead component of the base price amounts to $0.35 per MMBtu.

Note: Once established by the formula outlined herein, Sonatrach has maintained the $1.30 per million Btu FOB base price in negotiating new LNG contracts with European buyers.

47/ Although this price escalator formula is identical to the one approved by the FPC in the Trunkline case, DOE is of course not bound by that decision. In each case a decision has to be made as to whether the anticipated price increases which might result from the operation of a particular escalation formula are reasonable, in light of the public interest. In Distrigas, DOE's allowance of this price escalator formula must be viewed within the specific circumstances of the case. The Distrigas Project represented a gradual expansion of a small ongoing project. The transportation and receiving costs were identifiable because nearly all of the work necessary to expand the facility had been completed.

48/ No. 2 oil low pour, low sulfur 0.3 percent; and No. 6 residual fuel oil, low pour, low sulfur 0.3 percent.

49/ Premium crudes, above 35 degrees API gravity and less than 0.5 percent sulfur content, currently sell for between 80 cents and $1.50/bbl above the OPEC Saudi Arabian Light Crude Oil marker price of $12.70/bbl FOB.

50/ The European currencies are the Belgian Franc, the French Franc, the West German Deutschmark, the Italian Lira, the Swiss Franc, and the British Pound.

51/ The applicants have still not filed a copy of the final transportation agreement between Tenneco LNG and Sonatrach.

52/ In this regard TAPCO's proposed minimum bill would enable it to recover equity costs from all nonjurisdictional facilities during periods of reduced or suspended delivery stemming from technical problems.

53/ In the Pacific Indonesia Decision, the DOE initially affirmed the Judge's decision which approved the Trunkline approach to cost recovery in the event of project failure prior to the commencement of deliveries. However, in the event of project failure after start-up the DOE permitted only certain costs to be flowed through to the consumer and required that the recovery of all other costs would be subject to a "Section 4-type" filing by Pacific Indonesia. This issue is currently under rehearing.

54/ TAPCO provided a copy of an American Gas Association study which contends that importing LNG is more advantageous than additional oil imports. The study argues that U.S.A. sales of project related equipment to the LNG exporter and U.S.A. participation in the transportation of LNG will result in a lower per unit dollar outflow than is realized from oil imports. It is a generic study, however, and does not deal with such factors as a receiving terminal located abroad.

55/ See Supplemental Comments of Tenneco Atlantic Pipeline Company and Tennessee Gas Pipeline Company concerning Matters Raised During the Oral Argument, pp. 10-12 and Appendix A, August 18, 1978.