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HIGHLIGHTS

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FERC Issues Final Rule Governing Deregulated High Cost Gas Categories

In Order No. 78 (RM79-44) issued 4/22/80, the FERC adopted a final rule establishing definitions and procedures for handling the four categories of high cost gas which were deregulated pursuant to NGPA Section 121(b) on 11/1/79 (the effective date of the first phase incremental pricing rule prescribed under Section 201 of the NGPA). The four deregulated high cost categories -- identified in Section 107(c)(1)-(4) -- include natural gas produced from deep wells completed below 15,000 feet (which commenced to be drilled on or after 2/19/77), occluded natural gas produced from coal seams, gas produced from geopressurized brine, and gas produced from Devonian shale. 1/

The final rule amends interim regulations previously issued on 10/24/79 in several respects. The interim regulations defined natural gas produced from geopressurized brine, natural gas produced from Devonian shale, and occluded natural gas produced from coal seams; directed that producers apply for a jurisdictional agency determination in order to qualify gas under one of these categories, with the determination to become final if not reversed or remanded by the FERC within 45 days; and specified that deregulated prices for qualifying wells may not be collected until a jurisdictional agency determination becomes final, i.e. no longer subject to Commission review, with the gas to be governed by the otherwise applicable maximum lawful price until that time. Once a determination becomes final, retroactive price adjustments (if specifically contractually authorized) may be made for deliveries from 11/1/79 or the date the application was filed, whichever is later, up to the difference between the price collected for such deliveries and the deregulated contract price (plus interest).

When issuing the interim regulations, the Commission requested comments on, among other things, (1) whether the final rule should allow interim collection of the lesser of the contract price or the section 102 maximum lawful price, together with retroactive collection of the amount (if any) by which the contract price exceeds the Section 102 maximum lawful price once a determination becomes final; and (2) whether pipeline or affiliate production qualifying under the applicable high cost categories should receive the deregulated price or be restricted to a ceiling price (and what ceiling price) in the event such production is not accorded first sale treatment. Comments were subsequently filed by producers, pipelines and other parties in late November. Virtually all producer comments urged inclusion of a provision for interim collection of deregulated prices pending finality of jurisdictional agency determinations, and elimination of the requirement for specific contractual authorization as a condition to retroactive collections. (See REPORT NOS. 1233, pp8-10; 1235, pp13-14; 1238, pp15-17.)

The final rule prescribed in Order No. 78 modified the interim regulations so as to provide for interim collection of the Section 102 maximum lawful price subject to refund pending review of jurisdictional agency determinations. On further consideration, the FERC concluded that Section 503(e) of the NGPA -- which permits interim collection of the maximum lawful price sought by an application for a jurisdictional agency determination -- was not intended by Congress to preclude establishment of a method to allow interim collection of some price other than an applicable maximum lawful price or to create a cash flow problem for Section 107

1/ A fifth category of high cost gas identified in Section 107(c)(5) -- i.e., gas "produced under such other conditions as the Commission determines to present extraordinary risks or costs" -- was not deregulated upon implementation of incremental pricing and is not covered by the final rule.

gas. However, the Commission disagreed with comments that interim collection of the deregulated rate is necessary to guarantee commencement of high cost production immediately after applications are filed. Rather, the Commission selected the Section 102 maximum lawful price for interim collection purposes since that price was deemed adequate by Congress to encourage development of both deep, high cost gas (until deregulation) and new reserves of natural gas. Moreover, the Commission declared, although interim collections of deregulated prices would be subject to refund and might not have any significant impact on ultimate consumers of gas, "large amounts of money could be collected during the interim collection period, and producers would have little incentive to pursue timely determinations." Thus, on balance, the Commission concluded that restriction of interim collections to the Section 102 ceiling will serve to limit the amount of money collected subject to refund "without seriously disadvantaging producers," especially since the retroactive collection provisions permit eventual full recovery of the deregulated price.

With respect to retroactive collections, the final rule deleted the necessity for specific contractual authorization to permit such collections. The Commission noted producer arguments that Order No. 23 (relating to the contractual authority provided by area rate clauses to collect NGPA maximum lawful prices) left questions regarding sales contract interpretations to the contract parties, and that many contracts consequently do not specifically provide for retroactive collection. The Commission concluded that the same policy favoring contract interpretation by the parties thereto should also be applied to deregulated gas. Retroactive collections may be made for deliveries since 11/1/79 or the date an application was filed for a deregulated gas determination, whichever is later, except that gas covered by an application filed within 60 days from the effective date of the final rule (4/22/80) will be eligible for retroactive collections respecting any deliveries back to 11/1/79.

The final rule also directed separate billing of deregulated gas. This requirement clarified language in the interim rule respecting the need for "unbundling of gas sales transactions so that regulated and unregulated transactions are separately priced." The Commission expressed concern that situations could arise where prices paid for deregulated gas might represent partial consideration for the sale of regulated gas. Thus, to deter circumvention of maximum lawful prices when price-regulated gas is sold in association with deregulated gas, the Commission required that all first sales of deregulated high cost gas be separately billed.

In regard to pipeline and affiliate production, the Commission noted its prior determination in Order No. 58 (issued 11/14/79) that sales by a pipeline or distributor affiliate will generally qualify as a first sale provided such affiliate is not itself a pipeline or distributor. However, Section 601 of the NGPA specifies that a pipeline may recover no more for first sale purchases from an affiliate than "the amount paid in comparable first sales between persons not affiliated with such interstate pipeline." Therefore, to ensure its ability to determine whether purchased gas acquisition costs for affiliate production do not exceed the amount paid in comparable first sales between nonaffiliated entities, the final rule requires pipelines to separately designate purchases of deregulated high cost gas from affiliated entities in their schedules of gas costs filed with the Commission.

As to pipeline production, which generally will not qualify as first sales under Order No. 58, the Commission decided to defer questions of pricing such production qualifying as deregulated gas until conclusion of the currently pending rulemaking proceeding (RM80-5) involving overall pricing of pipeline production.

Finally, the Commission modified the definitions of (1) "natural gas produced from geopressured brine" -- which is defined in the final rule as "natural gas which is dissolved before initial production of the natural gas in subsurface brine aquifers with at least 10,000 parts of dissolved solids per million parts of water and with an initial reservoir geopressure gradient in excess of 0.465 pounds per square inch for each vertical foot of depth" (the definition in the interim regulations referred to at least 10,000 parts of "sodium chloride" rather than "dissolved solids" per million parts of water); and (2) "natural gas produced from Devonian shale" -- defined in the interim regulations as "natural gas produced from the fractures, micropores and bedding planes of shales deposited during the Paleozoic Devonian Period," with this definition expanded in the final rule to cover any gross Devonian age stratigraphic interval where at least 95% of the interval has a gamma ray index of 0.7 or greater. The Commission explained that the definition in the interim rule was too restrictive in precluding qualification of gas produced from formations which contain too much shale to be considered anything other than shale for purposes of completion practices, but contain enough quartz or other coarser material to be designated stringers of other rock. The Commission accepted a suggestion in one comment to use a gamma ray index for calculating shale content.

No change was made in the definition of "occluded natural gas produced from coal seams."

FERC Proposes Rule to Limit Prices Received by Producers Accepting Advance Payments in the Future

On 4/23/80 the FERC issued notice of a rulemaking proposal (RM80-52) to limit the price received by producers who accept certain advance payments in the future to not more than 50% of the applicable maximum lawful price until delivery of sufficient gas to repay the advance payment plus interest. The proposal would apply to all first sales of natural gas (both interstate and intrastate) not subject to the 83¢/MMBtu carrying charge credit which was initially adopted by FPC Opinion No. 770-A (issued 11/5/76) for post-1974 interstate gas where the seller accepted an advance payment after 11/5/76 and the advance was included in the interstate pipeline buyer's rate base, and which was continued by the Commission's regulations implementing the NGPA for gas covered under Sections 104 and 106(a). The Commission said the purpose of the proposed rule is to prevent producers from circumventing the NGPA by receiving maximum lawful prices plus the use of interest-free capital over time.

Written comments on the proposed rule are due 6/23/80. A public hearing is scheduled for 7/1/80.

By order dated 12/31/75, the FPC terminated rate base treatment for advance payments made by interstate pipelines to producers under advance payment contracts executed after that date. However, the Commission provided that advance payments made until 12/31/80 under contracts executed between 10/2/70 (the date of Order No. 410 initiating the Commission's advance payment program in the early 1970's) and 12/31/75 could continue to receive rate base treatment. Thereafter, in Opinion No. 770-A establishing nationwide rates for post-1974 gas, the Commission sought to discourage further advance payments by requiring producers who received an advance after 11/5/76 to deduct the carrying cost of the advance (otherwise borne by the pipeline's customers) from the nationwide just and reasonable rate applicable to the subject gas. The Commission calculated this carrying cost at 83¢/MMBtu (the difference between the nationwide rate and out-of-pocket expenses). Subsequently, the FERC adopted the same carrying charge deduction in a special rule applicable to NGPA Section 104 and 106(a) first sales. As in Opinion No. 770-A,

the NGPA deduction applies only to advance payments made after 11/5/76 pursuant to contracts executed between 10/2/70 and 12/31/75.

In the instant rulemaking notice, the Commission noted that gas qualifying for an NGPA pricing category other than Sections 104 or 106(a) is not subject to the Opinion No. 770-A carrying charge credit. Thus, a producer with an advance payment contract executed after 10/2/70 and before 12/31/75 currently has an incentive to demand advance payments from an interstate pipeline, and the pipeline may include any such payments made before 12/31/80 in its rate base. In this way, the Commission declared, allowing advance payments without an appropriate adjustment for interest may enable producers to circumvent the maximum lawful prices under the NGPA. This possibility exists with respect to both interstate and intrastate markets, the Commission added. Also, if only interstate pipelines were prohibited from making advance payments to producers, the result would be a disparity in bargaining power between interstate and intrastate purchasers. For this reason, the FERC would apply the proposed rule on advance payments to all first sales not subject to the special rule currently embodied in the NGPA regulations.

The carrying charge adjustment in the proposed rule is designed to reflect the value of advance payments received by producers. As a measure of such value, the Commission contemplates use of the prime rate (compounded quarterly) as the approximate average cost of intermediate-term business loans. Also, the prime rate is easily determined, widely known, frequently used, and convenient to administer. 1/

To illustrate the mechanics of the proposed rule, the Commission hypothesized a situation where a producer received a $1 million advance payment one year before commencement of deliveries, the value of the advance during that one-year period was $100,000, and the contract rate ($2.00/MMBtu) equaled the maximum lawful price at the time of delivery. Thus, since the producer would owe the purchaser $1.1 million upon start of deliveries, the producer could collect only $1.00/MMBtu (50% of $2.00, the maximum lawful price for the gas) until at least 1,100,000 MMBtu of gas had been delivered. Once the advance payment plus interest had been repaid, the producer could collect the full maximum lawful price of $2.00/MMBtu.

The proposed rule also includes a definition of "advance payments," namely, "any payment made by any person to any other person in consideration of an obligation to make future delivery of natural gas in a first sale." Thus, the term includes prepayments, extended front-end advances, or any other form of predelivery payment or loan. Payments made under "take-or-pay" contracts, however, would not be considered as advance payments.

The Commission requested comments on (1) alternative means of treating advance payments made for section 104 or 106(a) gas which has been reclassified since the time the advance payment was made; (2) treatment of advance payments made prior to issuance of the instant notice but not subject to the rule carried forward from Opinion No. 770-A; (3) use of the prime rate, together with other possible means of reflecting the value of an advance payment to a producer; and (4) the desirability of outright prohibition of advance payments in both interstate and intrastate markets as an alternative to the proposed rule.

1/ The FERC also adopted the prime rate as the interest rate on refunds and carrying charges in Order No. 47 (RM77-22), issued 9/10/79.

Chairman Curtis Discusses Policy Questions Raised by Phase II of Incremental Pricing

On 4/22/80 FERC Chairman Charles Curtis addressed the National Energy Resources Organization in Washington, D.C. on policy questions raised by Phase II extension of the incremental pricing program established in the NGPA.

While the Commission was given very little administrative discretion in developing Phase I rules (applicable to industrial boiler fuel users of natural gas) except some latitude regarding the level of alternative fuel costs, Mr. Curtis said, the Phase II task of broadening incremental pricing is a "much more complicated assignment." This is especially so since the Commission's ability to give effect to the Congressional purposes underlying Phase II seems "imperfect at best." The Commission has tentatively concluded that extension of incremental pricing to industrial process and feedstock users will not serve the market ordering objective intended by Congress, although it will further the Congressional purpose of sheltering high priority users from some of the burden of increased gas costs. Hence, the Commission will send Congress by 5/9/80 a rule expanding incremental pricing to cover all industrial facilities that are not statutorily exempt. The Commission has opted to propose a broad rule, the Chairman continued, because this maximizes the sheltering impacts for high priority users, and there is no satisfactory basis for distinguishing one industry group from another. However, because of concern over potential economic dislocations that could result from rapid and significant price increases to industry, the Commission will recommend establishing the alternative fuel price cap permanently at the high sulfur No. 6 level and will also suggest exempting the first 300 Mcf/d of deliveries. 1/

Chairman Curtis stressed that the basic question surrounding the implementation of Phase II -- whether the risk of economic dislocation in requiring industry to shoulder a higher burden for increased gas costs is outweighed by the social benefits achieved in sheltering higher priority users -- is one for Congress, and Congress alone, to decide. However, the Chairman outlined some of the considerations bearing on analysis of this question.

On the one hand, the Chairman stated, natural gas is considered the nation's most valuable fossil fuel, representing the primary fuel for residential needs and accounting for nearly 30% of industrial needs. The minimum commodity value of natural gas is the price of high sulfur No. 6 residual fuel oil, he observed, and pricing policies failing to reflect this minimum commodity value tend to encourage waste and subsidize imports. Further, Mr. Curtis noted, the No. 6 high sulfur residual fuel oil price published for the month of April 1980 is less than the marginal supply price for most interstate pipelines. For example, current delivered prices of high sulfur residual fuel oil are approximately $3/MMBtu, or only two-thirds of the current $4.47/MMBtu price of imported Canadian gas at the border. If industry were to encounter permanent difficulty in remaining profitable with natural gas priced on a par with high sulfur residual fuel, Mr. Curtis said defeat of Phase II incremental pricing might simply postpone the problem, not cure it. To the extent that this problem is merely transitional, however, it can be argued that industrial users may be better able than residential users "to manage the distributive difficulties presented by rapid increases in energy prices" because of potential ability to pass on increased fuel costs in higher prices for goods and services. At the same time, to the extent that industry is unable to pass through higher fuel costs, "the result of incremental pricing may be anti-inflationary (albeit perhaps recessionary) in its ultimate impacts."

1/ The Commission will consider the final details of the Phase II rule at its next open meeting on 4/30/80.

On the other side of the ledger, the Chairman noted, is the question whether residential users of natural gas -- who incurred only about a 15% increase in costs compared to a nearly 50% rise in purchased gas costs of interstate pipelines between August 1978 and August 1979 -- have an equitable claim to shelter from this impact, especially when other residential users dependent upon oil and electricity for spaceheating requirements have no comparable program to mitigate the burden of increased energy costs. A further question is whether the Phase II incremental pricing program should be deferred until a time closer to 1985 when the most significant price impacts under the NGPA are likely to occur. Finally, inasmuch as the burdens of incremental pricing must be borne by industrial users accounting for only 15% of interstate consumption while the benefits are distributed over the remaining 85% of the load, one may ask whether the benefits are "spread so thin as to be relatively insignificant compared to the burdens allocated to industrial facilities." Considering the prospects of a general downturn in the economy, "why risk adding to recessionary pressures for so small an individual benefit?"

In short, Chairman Curtis declared, the above questions involve social and political judgments. "The answers are not straightforward. It is, to me, a difficult riddle whether to go forward with Phase II or not." 1/

Energy Information Administration Publishes Alternative Fuel Ceilings for May 1980 Substantially Lower than April 1980 Ceilings in Most States

On 4/18/80 the Energy Information Administration published in the Federal Register alternative fuel price ceilings to apply during ~~May~~ June 1980 for purposes of implementing Phase I of the incremental pricing program mandated by Title II of the NGPA. ~~2/~~ 1/

Compared with the ceilings effective for April 1980, those published for May 1980 are lower in all but five states (Colorado, Idaho, North Dakota, Rhode Island and Utah) and 40¢/MMBtu or more lower in 30 states. Further, in some states, the ceilings were below $2.00/MMBtu for the first time since EIA commenced to compile and publish alternative fuel price data in December 1979.

The alternative fuel price ceilings originally published by EIA on 3/20/80 for the month of April 1980 -- which exceeded March 1980 ceilings in most states (by amounts ranging from 20¢ to $1.05/MMBtu in 30 states) -- were revised by the FERC on 3/28/80 because of concern over fuel switching by industrial gas customers subject to Phase I. In support, the Commission noted reports of actual high sulfur No. 6 oil prices below the EIA published ceilings in several states, as

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1/ Bills to repeal the incremental pricing provisions of the NGPA have reportedly gained 96 sponsors in the House and 15 sponsors in the Senate.

1) ~~2/~~ In addition, EIA published an incremental pricing threshold of ~~$7.38~~ $8.04/MMBtu to apply during ~~May~~ June 1980 for high cost natural gas -- which, under Section 203(a)(7) of the NGPA, is subject to incremental pricing to the extent that the first sale acquisition cost exceeds 130% of the weighted average cost of No. 2 fuel oil landed in the New York metropolitan area during an appropriate period preceding the month of natural gas delivery. The ~~$7.38~~ $8.04/MMBtu threshold was based on a ~~$32.91~~ $35.88/bbl. price of No. 2 distillate fuel oil landed in the greater New York City area in ~~February~~ March 1980, multiplied by 1.3 and then converted to a Btu basis using a 5.8 factor. ~~The~~ Comparable incremental pricing thresholds determined for ~~April 1980~~ the previous two months were considerably lower -- ~~was~~ $7.11/MMBtu (based on a landed price of $31.74/bbl. ~~of No. 2 fuel oil~~ in January 1980) and $7.38/MMBtu for May 1980 (based on a landed price of $32.91/bbl in February 1980).

well as continuation of a recent downward trend in market prices for residual fuel oil. The revised ceilings for April 1980 were lower than the original ceilings in 40 states (by amounts ranging from 15¢ up to $1.23/MMBtu). ~~The Commission pro-~~ vided that the lower of EIA's originally published ceiling or the subsequently revised ceiling for each state would apply for April. (See REPORT NOS. 1255, pp3-5; 1256, pp1-2; 1257, pp23-25.)

The ceilings calculated by EIA for May 1980 reflect the same two computational revisions (with certain modifications) introduced by EIA in the alternative fuel price ceilings originally published on 3/20/80 for April 1980. Specifically, rather than relying on data collected for a single month, the May ceilings are based on volumetrically weighted average prices of high sulfur No. 6 residual fuel oil reported for three months, ~~December 1979~~ Jan. 1980 - ~~February~~ March 1980. Reported prices for No. 6 fuel oil sales in ~~December 1979~~ Jan. 1980 were adjusted by the percent change in the nationwide volume-weighted average price from ~~December~~ Jan. to ~~February~~ March. Prices for ~~January~~ Feb. 1980 were similarly adjusted by the percent change in the nationwide volume-weighted average price from ~~January~~ Feb. to ~~February~~ March. The volume-weighted three-month average price for each state was then adjusted downward by two standard deviations calculated for the applicable region (one of eight) in which the state is grouped by the FERC. These adjusted weighted average prices were then compared with the average of the lowest high sulfur No. 6 residual fuel oil prices determined for each month of the three-month period (adjusted up or down by the percent change in oil prices at the national level), with the higher of the two average values in each state selected as the alternative fuel price ceiling.

~~As a final step,~~ It also EIA applied a lag adjustment factor as partial compensation ~~— its second computational revision introduced in March — to compensate~~ for the two-month lag between the end of the month for which data are collected and the beginning of the month for which the computed ceiling prices are to be effective. This adjustment factor was ~~based on~~ low posted prices for No. 6 residual fuel oil published by Platt's Oilgram for 20 cities throughout the U.S. ~~However, whereas the ceilings published by EIA on~~ 3/20/80 reflected four regional adjustment factors using the ratio between weighted average low posted prices for ~~10~~ 9 trading days ending ~~March 7~~ 5/13/80, and the weighted average regional price ~~posted published by Platt's for January 1980, the ceilings~~ published by EIA on 4/18/80 incorporate a national lag adjustment factor based on the weighted average price determined for a single trading day (April 11) divided by the corresponding weighted average price published by Platt's for the month of ~~February~~ March 1980 ~~to~~ obtain the lag adjustment factor.)

The alternative fuel price ceilings for May 1980 are tabulated below, together with those applicable for April 1980. Also shown for comparative purposes are EIA's ceilings originally published on 3/20/80 for April 1980.

determined on a nationwide basis
Employing

Alternative Fuel Price Ceilings

	State	June 1980	May 1980		April 1980 (~~As~~ Revised)	April 1980 (As Originally Published)
	Alabama	$2.22	$2.26/MMBtu		$2.68/MMBtu	$2.68/MMBtu
	Arizona	1.94	2.08		2.69	2.95
18	Arkansas	2.25	2.43		2.47	3.31
	California	2.34	2.27	H	2.68	3.15
17	Colorado	2.17	2.44		2.26	3.06
	Connecticut	2.89	3.05		3.13	3.69
	Delaware	2.92	3.00		3.60	3.60
19	Florida	2.13	2.31		2.71	3.09
19	Georgia	2.36	2.55		3.08	3.08
27	Idaho	2.17	2.44		2.26	3.06
36	Illinois	2.17	2.53		2.88	3.62
	Indiana	2.48	2.60		3.20	3.35
	Iowa	2.23	2.31		2.73	3.01
	Kansas	2.25	2.26		2.73	2.82
	Kentucky	2.81	2.81	S	2.88	3.48
36	Louisiana	1.87	2.23		2.61	3.12
25	Maine	2.88	3.13		3.67	3.67
23	Maryland	2.62	2.85		3.40	3.64
21	Massachusetts	2.53	2.74		2.81	3.46
	Michigan	2.76	2.78		3.23	3.60
	Minnesota	2.61	2.74		3.15	3.50
	Mississippi	1.92	1.92	S	2.20	2.35
	Missouri	1.81	1.96		2.56	3.29
	Montana	2.20	2.06	H	2.26	2.49
	Nebraska	2.35	2.47		2.73	3.40
	Nevada	2.39	2.34	H	2.69	3.10
22	New Hampshire	2.99	3.21		3.80	3.87
23	New Jersey	2.53	2.76		3.37	3.58
	New Mexico	2.17	2.14	H	2.47	2.57
18	New York	2.55	2.73		3.20	3.21
	North Carolina	2.73	2.85		3.45	3.45
	North Dakota	2.73	2.84		2.73	3.52
21	Ohio	2.54	2.78		3.20	3.63
	Oklahoma	2.02	2.16		2.58	2.83
	Oregon	2.80	2.83		3.23	3.45
	Pennsylvania	2.62	2.80		3.33	3.39
	Rhode Island	3.17	3.27		3.13	3.77
	South Carolina	2.61	2.77		3.30	3.30
	South Dakota	2.62	2.72		2.73	3.96
	Tennessee	2.58	2.67		3.10	3.10
	Texas	2.00	2.14		2.86	3.04
22	Utah	2.53	2.75		2.26	3.42
19	Vermont	2.97	3.16		3.80	3.80
	Virginia	2.61	2.78		3.18	3.23
	Washington	2.43	2.36	H	2.79	2.84
	West Virginia	2.58	2.66		3.10	3.44
	Wisconsin	2.68	2.70		3.13	3.46
	Wyoming	1.90	1.94		2.26	2.63

ERA Grants Rehearing for Purpose of Further Consideration of Opinion No. 14 Denying Projects by Columbia Gas and Montana Power to Import Canadian Gas at Latest Border Price of $4.47 per MMBtu; Requests Additional Comments on Relevance of U.S. and Canadian Agreement on Pricing Mechanism

On 4/23/80 the ERA issued Opinion No. 14-A granting -- for purposes of further consideration -- applications by Columbia Gas Transmission Corp. (79-30-NG) and Montana Power Co. (79-16-NG) for rehearing of Opinion No. 14 insofar as it denied their applications to import new gas from Canada at the recently increased export price of $4.47/MMBtu. The ERA also requested comments by 5/1/80 on the recent agreement by DOE Secretary Duncan and Canadian Energy Minister Lalonde on a revised mechanism for pricing Canadian gas exports to the U.S. commencing 4/1/80.

In Opinion No. 14, the ERA concluded that the new import price "is not reasonable" and should be denied with respect to the new projects. The ERA observed that Canadian export prices have steadily increased over the past five years -- from $1.00/MMBtu (Canadian) effective 11/1/74 to the proposed $4.47/MMBtu (U.S.) effective 2/17/80. This included a dramatic increase of more than 100% in less than a year -- from $2.16 to the proposed $4.47/MMBtu.

In addition, the ERA could find no showing of near-term need for the gas proposed to be imported by Columbia Gas and Montana Power. In the case of Columbia Gas, the ERA referred to the recent Columbia LNG Algerian import proceeding where there was "abundant and uncontradicted evidence" that Columbia Gas has gas surplus over its customers' estimated current and near-term future needs. Montana Power, meanwhile, has not been taking all the gas it is authorized to import from Canada -- only 30.1 Bcf in the contract year 1979 compared to authorization to import 39.2 Bcf. Moreover, ERA added, Montana Power has not been drawing down fully on its imports in the current contract year. "It is thus apparent that Montana can meet all near-term supply requirements by drawing upon other sources, including other gas currently flowing from Canada." Thus, ERA concluded, "in each instance, we believe there has not been a showing of compelling immediate need for these new gas supplies . . . ."

Opinion No. 14 also (1) denied an application by Northern Natural Gas Co. (78-002-NG) to import about 10 Bcf annually by displacement from Union Gas Co. Ltd. over a five-year period beginning in the 1979-1980 heating season at the increased border price; 1/ and (2) granted applications by seven other pipelines to continue imports of gas currently flowing from Canada at the increased rate for the interim period 2/17/80 through 5/15/80, pending development of an administrative record and possibly a hearing on whether such imports should continue at the new price.

1/ Northern's application had been previously approved by ERA on 1/15/80 at the then current border price of $3.45/MMBtu. In Opinion No. 14, however, the ERA noted that the FERC is still conducting a review of certain tariff aspects of the price flowthrough and no gas has begun to flow under the prior approval. "Therefore, for all practical purposes, the application by Northern for approval of a new price for the gas . . . is an application for authorization to import new volumes, rather than flowing volumes . . . ." Hence, the ERA treated it as an application for approval of new gas volumes, and denied it along with the applications by Columbia Gas and Montana Power for new gas imports. Northern did not seek rehearing.

In its application for rehearing, Columbia Gas, among other things, challenged ERA's new policy of requiring a showing of a "compelling immediate need" for imported Canadian gas, instead of showing of long-term need as required in all previous gas import proceedings. Columbia Gas also objected to summary denial of its import application without the opportunity for hearing on merits of the application, and to address the ERA's new policy of comparing the price of Canadian gas imports with residual fuel oil prices -- which led to rejection of the increased price because it is not competitive.

Montana Power explained in its application for rehearing that the primary purpose of the import involved in its application was not to provide additional gas supply but to provide a solution to a gas drainage problem. Specifically, Montana Power explained, its wells located immediately adjacent to the Montana-Alberta border have been draining gas from that portion of the Canadian side of the field adjacent to the border, and this action was objected to by Canadian producers. Accordingly, the instant application was filed "to solve a potentially serious and embarrassing international border accommodation problem."

As noted, in late February the U.S. and Canada agreed to a more regularized formula for determining gas export prices after the U.S. objected to the increase in border price to $4.47. As of 1/1/80, this formula yielded an export price of $4.47. Subsequently, Canada reportedly agreed to delay any further increases in the border price to the U.S. until 10/1/80. (See REPORT NOS. 1244, pp24-26; 1249, pp1-4; 1253, pp12-14; 1254, pp8-9; 1256, pp7-13; 1257, p1.)

In Opinion No. 14-A, the ERA noted that in their applications for rehearing of Opinion No. 14, Columbia Gas and Montana raised issues concerning the need for gas imports and the price at which they should be permitted to enter the U.S. Also, Columbia Gas questioned whether the grounds underlying the ERA's conclusion were consistent with its previous policies. "Since the further proceedings to be conducted pursuant to Opinion No. 14 will consider the need for Canadian gas, as well as the appropriate import price, the petitions for rehearing filed by Columbia and Montana are granted for the purpose of further consideration. The merits of their arguments will be considered subsequent to the completion of the further proceedings scheduled under Opinion No. 14."

The ERA also observed that on 4/14/80, Columbia Gas refiled its initial application, stating that the $4.47 border price is now consistent with the agreement reached between Canada and the U.S. (see next Highlight). However, the ERA stressed, that agreement specifically provided that the development of an orderly, systematic mechanism for determining prices sought by Canadian exporters "does not, in any way, bind the ERA in terms of its regulatory responsibilities. Each price calculation resulting from operation of the mechanism will still be subjected by ERA to the alternate fuel test, and an authorization to pay each of the increased prices will still be required."

In light of the new Canadian pricing mechanism and its relevance to the overall pricing issue, ERA requested the parties to provide further written comments (by 5/1/80) on the agreement and its implications for matters being considered in connection with ERA's overall price review in this proceeding. Also, because the existence of take-or-pay or minimum take clauses which exist in all of the import contracts are relevant to this review, the Commission directed each of the applicants to submit (also by 5/1/80) a detailed description of any take-or-pay, minimum take or any other similar obligations in their import contracts.

Opinion No. 14-A also (1) authorized the interim price increase to $4.47 pursuant to recent applications filed by St. Lawrence Gas Co. (80-09-NG) and Vermont Gas Co. (80-10-NG), which "by custom and practice" had not previously made separate applications to approve price increases for their Canadian imports, but were directed to do so in Opinion No. 14; and (2) granted various petitions to intervene in this proceeding.

Columbia Gas Refiles Application to Import Canadian Gas at $4.47 Rate Rejected by ERA Because Price Is Now Consistent with U.S.-Canadian Agreement

On 4/14/80 Columbia Gas Transmission Corp. filed applications in the ERA (79-30-NG) and the FERC (CP80-315) seeking authorization to import a total of 163.2 Bcf over a 15-year period (41,000 Mcf/d) from Columbia Gas Development of Canada, Ltd. at the current applicable border price of $4.47/MMBtu.

According to the application, the NEB on 12/6/79 granted Columbia Development a license to export about 84 Bcf over an eight-year period to Columbia Gas. However, in Opinion No. 14, the ERA denied Columbia Gas' application to import gas because the new import price was not in the competitive range of prices charged in the relevant U.S. market area for all alternate fuels (usually residual fuel oil) and hence "not reasonable." However, such denial was "without prejudice to refiling at such future time at the Canadian price is again consistent with alternate fuel prices."

In late February, the U.S. and Canada agreed to a more regularized formula for determining gas export prices after the U.S. objected to the increase in border price to $4.47. As of 1/1/80, the formula yielded an export price of $4.47. Subsequently, Canada reportedly agreed to delay any further increases in the border price to the U.S. until 10/1/80. (See REPORT NOS. 1249, pp1-4; 1253, pp12-14; 1254, pp8-9; 1257, p1.)

In its application, Columbia Gas stated that it is refiling its application to import gas from Canada pursuant to the ERA statement in Opinion No. 14 that it could do so when the Canadian price was consistent with alternate fuel prices. Columbia Gas noted that the Canadian export price in its application is consistent with the agreement in principle reached between the U.S. and Canada.

Columbia Gas also observed that it applied for rehearing of Opinion No. 14, which would be mooted by expeditious authorization of the refiled import application. However, if time constraints require, the ERA could grant rehearing of Opinion No. 14 for purposes of further consideration for a brief period until it acts upon the instant application (see previous Highlight).

The gas here involved will enter the United States at Sumas, Washington at the existing delivery point of Westcoast Transmission Co. which will transport the gas to the border, and Northwest Pipeline Corp. which will deliver the gas to El Paso Natural Gas Co. in LaPlatta County, Colorado. El Paso will then deliver portions to Columbia Gulf Transmission Co. in Southern Louisiana and to Northern Natural Gas Co. for delivery by displacement to Columbia Gulf in Southern Louisiana. Then, Columbia Gulf would transport all gas received from El Paso and Northern to Columbia Gas in Kentucky.

Senate Subcommittee on Energy Regulation Holds Hearings on "Backout" Legislation to Provide Grants for Conversion of Electric Powerplants to Coal or Other Alternate Fuel

On 4/23/80 hearings were held by the Senate Subcommittee on Energy Regulation on S. 2470 establishing a two-phased program to (1) provide some $6 billion in grants to cover capital costs for converting 107 specified powerplants from use of oil and natural gas to coal, to assist utilities in the design and installation of advanced sulfur dioxide removal systems and for construction and operation of coal cleaning and preparation facilities; and (2) authorize $6 billion for a voluntary program to achieve reductions in petroleum and natural gas use. The purpose of the Act is to reduce domestic use of petroleum and natural gas in the electric utility sector by at 400,000 b/d by 1985 and 1 million b/d by 1990. Testimony was presented by various Administration and state officials and a group of Senators generally supported the bill. 1/

On 3/6/80, President Carter submitted legislative specifications to Congress for a program of utility oil and gas displacement. On 3/24/80, Senator Wendell Ford (D-Ky.) introduced S. 2470 (for himself and 11 other Senators, including Majority Leader Byrd and Senator Jackson, Chairman of the Senate Energy Committee), and on 3/26/80, Rep. Harley Staggers (D-W.Va.) introduced H.R. 6930, a similar but not identical bill (for himself and 18 other Congressmen, including John Dingell, Chairman of the Energy and Power Subcommittee). Both bills contained the major provisions proposed by the President, with the Senate bill conforming more closely with the Administration's proposal.

S. 2470 would first prohibit oil and gas burning at 107 named powerplants designated on the basis of their size, remaining useful life and feasibility of converting to coal or alternate fuels. Federal grants totalling $3.6 billion would be provided to the utilities for as much as the lesser of 50% of the eligible capital costs associated with conversion or $4 per discounted barrel displaced. All powerplants converting would be required to meet all applicable environmental standards as well as any new standards which might be enacted to deal with environmental problems not covered under existing law.

In addition, $300 million ~~would be available~~ for grants to assist utilities in financing ~~the~~ installation of advanced sulfur dioxide removal systems (such as scrubbers and chemical coal cleaning) at existing powerplants and An additional $100 million ~~would be available~~ to assist coal producers in financing new coal-cleaning plants to reduce the sulfur content of raw coal destined for use in areas which are major sources of sulfur dioxide emissions. Up to 20% of the qualifying capital costs of a coal preparation plant would be eligible for funding. Awards under both of these programs would be made on a competitive basis.

If any of the 107 powerplants ~~is~~ units not in compliance with the ~~Act on~~ prescribed restrictions by 12/31/85, ~~it will not thereafter~~ could be ~~permitted to~~ prohibited from recover fuel costs ~~for the powerplant automatically~~ through an automatic adjustment clause. The second phase of the Administration program would have ~~The second major portion of S. 2470 would~~ provided $6 billion in grants to utilities who voluntarily seek grants to assist them in reducing reliance on oil and gas. A utility seeking grant support would be required to examine the financial feasibility, cost effectiveness and environmental impacts of all reasonable

1/ Hearings by the Subcommittee are scheduled to continue on 4/25/80 with witnesses representing the United Mine Workers of America, National Coal Association, Edison Electric Institute and several environmental and consumer organizations.

opportunities for displacing oil and gas on a systemwide basis. This would include conservation and peak load management programs, cogeneration, renewable energy resource systems, more efficient utilization of existing powerplants, synthetic fuels and construction of new powerplants.

Grants would be awarded on the basis of state approved fuel displacement plans ~~which~~ demonstrating ~~that~~ the utility ~~has selected~~ a cost-effective approach for reducing systemwide oil and gas consumption below a base line level defined as average annual use over the 1974-1978 timeframe. Grants would be awarded using a barrel-per-day displacement formula (measured relative to the base line). It would not be directly linked to the funding of specific projects or a percentage of total costs of the plan.

Initially, each utility would be eligible to apply for a share of the grant program in direct proportion to the percentage of oil and gas used by that system relative to total oil and gas consumption by all utilities (discounted for savings achieved under the required program). However, in order to receive an award, the utility must prepare a fuel displacement plan subject to review and approval by state authorities based on an assessment of the likelihood of meeting the displacement target and the practicability, cost effectiveness, financial feasibility and environmental impacts of the plan.

Some $40 million would be provided to state agencies to assist in their review of these plans, and an additional $10 million would be provided to state consumer offices to assure effective consumer participation in the review process and public hearings associated with plant approval.

A review of H.R. 6930 and hearings held on 3/2/80 by the House Subcommittee on Energy and Power appears in REPORT NO. 1255, pp6-10.

At the hearing on 4/23/80 before the Senate Subcommittee on Energy Regulation, most witnesses supported S. 2470, although modifications were proposed with respect to certain portions of the proposed program. At the outset, John C. Sawhill, Deputy DOE Secretary, testified as to the importance of this legislation to help meet the President's objective of achieving significant reductions in oil imports. The electric utility industry, he observed, currently consumes about 3 million b/d of petroleum products and natural gas (about evenly split). Moreover, he continued, growing delays and deferrals in completion of new coal and nuclear powerplants could easily result in a net increase in utility oil and gas consumption by 1990 even though few new oil or gas-fired powerplants will be built. "Thus, without a carefully designed program which links aggressive energy conservation efforts with accelerated conversion or replacement of existing oil and gas-fired powerplants, utility consumption of scarce fuel is likely to increase over the next decade."

Secretary Sawhill described results achieved thus far at converting existing oil and gas-fired powerplants to coal or alternate fuels pursuant to the Energy Supply and Environmental Coordination Act and Powerplant and Industrial Fuel Use Act as "disappointing." And this is so, he stressed, despite attractive economics and growing federal regulatory pressure to convert. Mr. Sawhill stressed that the major reason for a lack of conversion under these Acts is the "poor financial situation of the nation's electric utility industry and especially those utilities with a heavy oil dependence. A further complicating factor is the lengthy regulatory process associated with conversion from oil and gas to coal."

More specifically, he explained, based on an assessment of the generally accepted measures of financial viability, most electric utilities who could convert simply lack financial capability to raise additional capital. "Most are already having a difficult time financing the new capacity needed to meet even today's lower growth rates." Moreover, he continued, based on current and projected cash earnings, these companies are constrained and in some cases legally precluded by interest coverage provisions of bond indentures from obtaining additional debt to finance conversion no matter how economically attractive. Furthermore, confronted by poor cash earnings, the tightest capital markets and highest interest rates in recent history and the depressed market value of existing equity issues, most utilities "will do all within their power to minimize their exposure to new capital requirements."

With respect to regulatory constraints, Secretary Sawhill noted the standard regulatory accounting practice in most jurisdictions whereby a new investment -- which may reduce electricity prices over the long run -- has the effect of increasing rates to consumers in the near term. This "rate bubble," he said, is a major disincentive to ratepayer financing of capital investments which are not needed to meet load growth.

Senator Henry Bellmon (R-Okla.) expressed concern over discouraging the use of natural gas in electric powerplants in light of the current surplus of supply. Secretary Sawhill responded that any such gas supply surplus is temporary and should not be relied on for these uses. Moreover, he said, powerplants must convert from using natural gas under the Fuel Use Act by 1990 in any event and he would not recommend to Congress that the law be changed.

Senator Pete Domenici (R-N.Mex.) asked whether, in light of the alleged inability of the powerplants to afford conversion on their own, the 107 named companies were asked to assess the economics of conversion with federal support for only 50% of the cost. Secretary Sawhill responded that each company was not surveyed, but DOE made its own analysis concluding that such amount would be sufficient.

Douglas M. Costle, Administrator of the Environmental Protection Agency, expressed "wholehearted support" for the increased use of coal "in an environmentally sound manner," and efforts aimed at converting utilities which burn oil and gas to the use of coal. He stated that the conversions permitted under the first phase of S. 2470 would not violate existing Clean Air Act state implementation plans but would increase emissions of sulfur and nitrogen oxides in the northeastern U.S. by as much as 15% to 20%. And this in turn may cause a 10% to 15% increase in acid deposition according to preliminary estimates. "We cannot presently say with certainty how much more ecological damage that will cause, we can say with certainty that the existing burden of acid deposition will be made worse. Adverse effects already associated with acid rain can be expected to worsen somewhat as a result of any increase in emissions of sulfur oxide and nitrogen oxide into the atmosphere."

Mr. Costle emphasized that the President included $400 million in this propoal to fund emission reductions on a voluntary basis and will propose additional measures after further discussions with Congress. The witness went on to describe other efforts under way by EPA and others to deal with acid deposition problems.

Under questioning by Subcommittee Chairman J. Bennett Johnston (D-La.) as to whether he in fact supports the bill, Mr. Costle responded that he does although he would prefer more emphasis on acid deposition protection. He stated that the acid deposition problem has only recently been recognized and is not taken into account in current environment law. Since S. 2470 requires conformance with

existing law, he is concerned that it does not completely ensure again all adverse consequences (i.e., acid deposition) of coal burning. Nevertheless, he stressed, coal remains an attractive and viable alternate to nuclear power if "done right."

Alice M. Rivlin, Director of the Congressional Budget Office, expressed doubt that Federal Government loans or loan guarantees would provide "more than a minimum amount of conversion. The problem is that federal loans or guarantees are likely only to replace private loans. This in turn limits the utilities' ability to raise future debt capital unless they also increase their equity financing. The latter may be precluded since it dilutes the individual utility's earnings.

She suggested that an alternative to grants would be regulatory reform which would eliminate the current bias which is against new coal capacity and favors continuing operation of current oil and gas plants. Some important aspects of regulatory reform, she said, would most likely include allowing utilities to include work in progress in their rate base, limiting the use of automatic fuel adjustment clauses and guaranteeing an adequate rate of return on invested capital. State public utility commissions, she declared, would "do well to emulate" the FERC's recent treatment of a coal conversion project of New England Power Co. where the utility was allowed to include conversion costs in its rate base and increase its interim rates.

Ms. Rivlin observed that while a grant program would likely stimulate faster reconversion than a program of regulatory reform thereby making the goal of 400,000 b/d by 1985 obtainable, progress toward a long-term goal of displacing 2 million b/d "would most likely not be very rapid unless the grants were much larger than currently anticipated." Regulatory reform, on the other hand, would probably enable faster retirement and replacement, and therefore, "represents a more effective long-run policy for achieving the potential conversion of up to an additional 2 million b/d of oil equivalent." Furthermore, she added, a grant program would improve the short-run cash flow position of the utilities whose facilities were eligible for the program, but would not alter their incentives toward continuing to operate oil and gas instead of converting to coal which would be less expensive over the long run. On the other hand, regulatory reform should alter those incentives thereby accelerating the rate of conversion while also improving a long-run financial outlook of the industry.

Charles A. Zielinski, Chairman of the New York PSC, first challenged the "widely held assumption among supporters of a massive coal conversion program that oil prices are now so high in relation to coal that it must be economic to convert any oil or natural gas-fired plant that once burned coal back to its original fuel." The witness declared "that a strong case can be made for the proposition that the economics are not so clear with respect to all such conversion and, therefore, that there is a genuine risk that conversions to coal that might appear to lower costs for consumers may not in fact do so." The witness rejected the common analysis which assumes that the current differential between oil and coal prices will persist far into the future or even widen. "In point of fact, there is no way of knowing, with certainty, whether an investment in conversion will lower costs for consumers until the future becomes the present. Therefore, there is some economic risk involved in a conversion investment."

Nevertheless, Mr. Zielinski agreed that as a matter of national policy, legislation should be enacted to facilitate the investment of capital needed to reduce the consumption of imported oil and electric generation. However, it ought to be done through a program of loans rather than outright grants for coal conversion. First, he said, the loan program would have to be sufficiently large to pay for all

construction necessary to convert plants specified by the government, including necessary environmental controls and equipment. This would moot any argument that the program is not sufficient to fund all conversions and would provide an assured source of capital the utilities could obtain without harming their shareholders. Second, the witness continued, the loan would have to be in the form of a refundable contribution in aid of construction -- i.e., the money would be advanced by the Federal Government to the utility and would be repaid on condition that the fuel cost savings occur, on an annual payment schedule based on the actual annual fuel cost savings.

This, Mr. Zielinski said, would negate the problem that such loans would be considered additional debt at a time when the electric utilities already have too much debt and have difficulty meeting coverage requirements in their indentures. Also, in effect, the Federal Government would assume the risk that fuel cost savings may not be sufficient to cover the cost of making the conversion, and consumers would be protected because they could be no worse off than if the conversion had not been made. Moreover, to assure that consumers receive immediate fuel cost benefits from conversions, the fuel cost savings should be provided each year with part going to lower electric rates and part going to pay off the federal conversion loans.

However, the witness added, the voluntary portion of the proposed program should be subject to grants rather than loans as proposed. The key to the loan program, he explained, is the calculation of natural fuel cost savings which would be a manageable task in the case of conversions of existing plants. However, the voluntary program involves new production capacity. Hence, with growth occurring in demand for electricity, it would be difficult to distinguish new production plant that is satisfying growth in demand from a new plant that is displacing oil and producing fuel cost savings. In principle, the loan should only be available for investment that displaces oil or gas and is likely to produce fuel cost savings. In fact, however, a new production plant may satisfy both purposes to some degree, and initiatives that satisfy both purposes may in fact be the most economic and sensible to pursue. In view of this problem, the witness concluded that a grant program is the most practical approach to funding initiatives, other than conversions, to reduce electric utility oil and gas consumption.

William B. Sturgill, Secretary of the Kentucky Department of Energy, testified that coal reserves in the United States account for 90% of energy reserves, but are supplying only 19% of energy needs. The industry, he declared, has the capability to produce the 1.2 billion tons called for by the President by 1990. In addition to the fact that these proven reserves of coal exist, the development thereof "represents an important factor in the future economic development of all coal-producing states." In Kentucky, for example, coal plays a major role in the state's economy. S. 2470 could mean an increase in demand for Kentucky coal of about 7.8 million tons per year which would go a long way toward eliminating the current excess production capacity in the industry, put miners back to work, and move the country one step farther away from use of oil.

Testimony was also submitted by Majority Leader Byrd and Senators Jennings Randolph (D-W.Va.), Charles Percy (R-Ill.), Daniel Moynihan (D-N.Y.), Walter Huddleston (D-Ky.), and John Heinz (R-Pa.). Each of these Senators expressed support for S. 2470. They agreed that Congressional intent in prior legislation for conversion by powerplants and other major fuel burning installations from oil or natural gas has not been successful because of regulatory and other reasons. Moreover, they stressed the existence of large coal reserves which can be burned cleanly. Senator Byrd emphasized that it is "too simplistic" to suggest that this

country should merely reduce its energy demands to deal with present energy shortages. While there is no question that conservation is one of the most cost effective energy sources and must be pursued aggressively, he declared, "we cannot turn the clock back on American industry. Approximately 220 million Americans depend for their livelihood on the vitality of our economy. The aspirations of minority groups and of the continuing influx of hundreds of thousands of foreign-born immigrants alike are predicated on the continuance of American industrial growth. This means we must utilize our plentiful domestic energy resources -- especially coal -- to secure our energy future."

Certain of the Senators offered various proposed changes to S. 2470. Among other things, it was recommended that (1) language be added to ensure that only domestic coal, not imported coal, be burned by utilities receiving grants; (2) Congress appropriate money for a comprehensive and immediate analysis of the impact of coal use on acid rain; (3) the grant of funds be extended to industrial as well as utility boilers; (4) "fast track" treatment be provided with regard to regulatory requirements, permits and grants either in this bill or through the proposed Energy Mobilization Board; and (5) conversions be "grandfathered" against federal, state or local laws which are not essential to public health or safety or passed after a conversion plan has been approved.

FERC Reaffirms Requirement that Pipelines Refund All Amounts Collected from Customers to Recover Louisiana First Use Tax If Tax Held Unconstitutional, Irrespective of Amounts Refunded by Louisiana; Show Cause Proceeding Instituted to Determine Whether Portion of First Use Tax Payments Should Be Collected from Owners of Liquid or Liquefiable Hydrocarbons

On 4/24/80 the FERC issued Order No. 10-C (RM78-23) amending procedures previously prescribed to govern interstate pipeline recovery of the Louisiana First Use Tax payments subject to refund. Concurrently, the Commission instituted a show cause proceeding (RM78-23, Phase II) to determine why payments of the First Use Tax resulting from transportation in Louisiana of natural gas containing liquid and/or liquefiable hydrocarbons, or from processing of natural gas to separate or extract such liquid or liquefiable hydrocarbons, should not be collected from the owners of liquid and liquefiable hydrocarbons, subject to refund, during the period of litigation over the constitutionality of the First Use Tax.

Background

The Louisiana First Use Tax -- enacted in July 1978 to become effective on 4/1/79 -- is assessed at a rate of 7¢/Mcf upon the first occurrence of any "use" of natural gas within Louisiana, provided that such gas is not otherwise subject to a severance, production or import tax levied by any state, territory or by the United States. The term "use" is defined to include, among other activities, the sale, transportation, processing or transfer of natural gas, but excludes natural gas consumed in production and processing operations, extraction of liquefied hydrocarbons, or the manufacture of fertilizer and anhydrous ammonia within the state. Since Louisiana imposes a 7¢/Mcf severance tax upon all intrastate production, the First Use Tax is effectively imposed solely on natural gas produced outside Louisiana, i.e., primarily federal offshore production. The Louisiana statute described the purpose of the tax as the "exaction of fair and reasonable compensation to the citizens of [Louisiana] for . . . damages to the state's waterbottoms, barrier reefs, and sensitive shorelines as a direct consequence of activity within the state associated with natural gas by the owners thereof."

Suits challenging the constitutionality of the First Use Tax are currently pending before the (1) Supreme Court which, on 6/18/79; agreed to consider an original complaint filed by eight East Coast and Midwest states (State of Maryland et al.

v. State of Louisiana, Oct. Term 1978, No. 83 Original), and (2) the Fifth Circuit which heard oral argument on 6/26/79 with respect to an appeal from a U.S. District Court order indefinitely staying federal court proceedings on the FERC's complaint and petition for injunctive relief pending the outcome of state court litigation on a request by the Governor of Louisiana for a declaratory ruling that the First Use Tax is legal, valid and constitutional. (FERC v. Shirley McNamara et al., No. 79-1403.)

In Order Nos. 10, 10-A and 10-B (issued 8/28/78, 12/20/78 and 3/2/79, respectively), the FERC established tracking procedures to govern recovery of the Louisiana First Use Tax by interstate pipelines, subject to refund. Among other things, Order Nos. 10 and 10-A required escrow of monies collected to cover the First Use Tax pending the outcome of judicial litigation over the validity of the tax and, if the tax is overturned, prompt refunds to the pipelines' customers. In Order No. 10-B, however, the Commission modified this requirement so as to provide pipelines an option to collect the First Use Tax either under an escrow procedure or, subject to certain conditions, a corporate undertaking procedure. The Commission specified that the corporate undertaking procedure could be selected only if a pipeline (1) "voluntarily" agreed to refund to its customers, within 60 days of the issuance of a final and nonappealable court order, all payments attributable to any portion of the First Use Tax found invalid, plus interest at not less than 6% (the present refund interest rate under Louisiana law) -- with this "voluntary" agreement to apply even if the state did not refund such payments plus interest to the pipeline; and (2) took all legal action necessary to enforce contract provisions which could require the other contracting party (such as a producer or gatherer) to pay the First Use Tax. The Commission observed that "most pipelines should have no problem accepting and complying with the first condition" given their view that Louisiana has an absolute obligation to refund all payments made under protest if the First Use Tax is ultimately held invalid.

Subsequently, on 3/30/79, the FERC accepted, conditionally accepted or rejected tariff sheets filed by 18 pipeline companies -- Arkansas Louisiana Gas Co. et al. (RP79-53 et al.) -- establishing temporary tracking provisions to collect the First Use Tax, effective 4/1/79. The Commission rejected at least one tariff filing which did not include a "voluntary" agreement to make refunds even if such refunds are not received from the State of Louisiana. Filings of several other pipelines were provisionally accepted subject to elimination of language reserving the right to contest the legality of the Order No. 10-B refund provision or otherwise seeking to limit any unconditional refund obligation irrespective of refunds by the State of Louisiana.

Numerous pipelines sought rehearing of both Order No. 10-B and the Commission's action on 3/30/79. A major contention advanced in the rehearing applications was that the Commission's requirement for "voluntary" refund of any First Use Tax payments ultimately found unconstitutional could force pipelines to return more to their customers than they would receive from the state. So long as all necessary and appropriate legal steps have been taken to recover contested tax payments from the state, the pipelines argued that any condition subjecting them to possible loss of unrecoverable tax payments was "unconstitutionally confiscatory." (See REPORT NOS. 1177, pp8-16; 1199, pp36-38; 1203, pp13-15; 1214, pp13-15.)

Order No. 10-C

In Order No. 10-C, the FERC modified Order No. 10-B so as to eliminate the escrow account option -- which was not selected by any of the interstate pipelines subject to the First Use Tax -- and deleted all references to "voluntary" agreements by pipelines using the corporate undertaking procedure to refund any portion of the First Use Tax found unconstitutional. However, the Commission retained the

prior requirement that pipelines make full refunds plus interest upon a final and non-appealable court order holding the First Use Tax unconstitutional. Absent this refund requirement, the Commission stated, ultimate consumers might be forced to bear the cost of an unconstitutional tax simply because the taxing state failed to refund the amounts it collected. Hence, a full refund provision assures that taxpayer-pipelines "will vigorously pursue refunds" from Louisiana in the event the First Use Tax is determined unconstitutional. In addition, a full refund requirement assures that taxpayer-pipelines will "vigorously prosecute suits for refund of the First Use Tax payments submitted under protest." Moreover, the Commission asserted, since the taxpayer-pipelines probably are the only persons with standing to sue Louisiana to compel refunds if the state fails to refund all amounts paid under protest, they "are not unduly burdened by the requirement that they promptly refund all amounts collected from their customers." Finally, considering representations by most affected pipelines and assurances by several state officals that Louisiana will promptly refund all amounts paid under protest if the First Use Tax is held unconstitutional, "it is most unlikely that the pipelines will even be exposed to any significant risk of loss, much less actually suffer any losses, as a result of the refund requirement."

If any pipeline losses materialize, the FERC added, such losses would be limited to interest costs during the time between payment of refunds by pipelines to their customers and the time Louisiana makes refunds. "Since Louisiana may make refunds at only 6% per annum, these losses will be limited to the difference between the prevailing interest rate and the 6% interest rate. Pipeline customers, however, will have incurred similar interest losses throughout the pendency of litigation of the constitutionality of the First Use Tax. Thus, if the interest rate on refunds is not increased above the 6% level, pipeline customers will incur losses because of the difference between the prevailing interest rate and the 6% interest rate. While pipeline customers are now suffering real and measureable losses, the pipelines' potential losses are speculative -- Louisiana would have to refuse to refund taxes paid under a tax found unconstitutional before any pipeline losses occur."

Further, the FERC declared, establishment of the special tracking mechanism to allow collection of the First Use Tax, combined with a full refund provision, "balances the interests and burdens of pipelines and their customers." Absent the special tracking mechanism, the Commission asserted, pipelines would be required to file a general Section 4 rate case to recover the cost of the First Use Tax, with the result that such cost might be offset by a decrease in the cost of another item in the overall cost of service. "The Commission has balanced this potential benefit to pipelines, i.e., lack of exposure to offsetting rate decreases, against the benefit to the pipeline's gas customers of full refunds upon a final court determination that the First Use Tax is unconstitutional."

The Commission also clarified the refund interest rate provision of Order No. 10-B to require pipelines to refund all interest in excess of 6% per annum received from Louisiana if Louisiana is compelled to make refunds with interest at a rate greater than the present 6% annual limit under state law.

Finally, the Commission directed pipelines to file a copy of all complaints filed in Louisiana protesting the constitutionality of the First Use Tax, as well as quarterly reports beginning 6/1/80 summarizing the status of the proceedings instituted by, or against, the pipelines.

Show Cause Proceeding

As noted, the Commission additionally ordered owners of liquid and liquefiable hydrocarbons which are separated or extracted from natural gas subject to the

First Use Tax, or are transported and delivered to processing and/or separation plants in Louisiana or other states, to show cause why payments of the First Use Tax imposed on interstate pipelines by reason of such activities should not be billed to and collected from them subject to refund -- as charges incurred by pipelines for their benefit -- while the constitutionality of the First Use Tax is litigated. The show cause proceeding was initiated under Part I of the Interstate Commerce Act -- as well as several sections of the Natural Gas Act -- since the courts have held the Commission does not have jurisdiction over the transportation of liquid hydrocarbons by natural gas pipelines under the Natural Gas Act. However, the Commission noted, the DOE Organization Act empowers it to set rates for transportation of liquid hydrocarbons by common carrier pipelines. "And, any natural gas pipelines transporting liquid hydrocarbons on the Outer Continental Shelf onshore must operate as common carriers."

The show cause listed the following uses for which the Louisiana First Use Tax might be collected from owners of liquid and/or liquefiable hydrocarbons: (1) transportation in Louisiana of natural gas containing liquid and/or liquefiable hydrocarbons to the inlet of a processing plant, or a measurement or storage facility, as a preliminary step in the separation of liquid hydrocarbons from the gas stream and/or the processing of the gas to extract liquefiable hydrocarbons, whether in Louisiana or any other state; (2) transfer of possession or relinquishment of control at the inlet of a separation and/or processing facility within Louisiana; (3) processing of natural gas for the separation and/or extraction of liquid and/or liquefiable component products or waste materials; (4) treatment of the gas within Louisiana; and (5) other ascertainable action within Louisiana such as the separation of liquid hydrocarbons from gas by the use of high pressure or low pressure separators.

Interstate pipelines collecting the First Use Tax were directed (1) to notify within 15 days all persons for whom they transport liquid and/or liquefiable hydrocarbons which are produced and/or transported with, and extracted or separated from natural gas subject to the First Use Tax, of the instant show cause order, and (2) file a statement within 25 days (with service on all persons so notified) showing First Use Tax payments made by month and by use since April 1979; persons for whom or by whom certain transportation, processing, separation or other activities specified in the Louisiana statute have been performed; volumes and source of gas "used" in such service or activity within the meaning of the First Use Tax; First Use Tax payments by month attributable to such services or activities; the source of such gas (OCS, Barksdale Air Force Base, Algerian imports); whether such gas is transported in interstate commerce or is commingled with gas transported in interstate commerce; volumes of gas not subject to the tax; and pertinent contract or certificate provisions requiring owners of liquid and liquefiable hydrocarbons to pay capital and/or operating costs incurred in rendering the listed services and activities. Each notified person may file a written response within 60 days showing why he should not be required to pay (subject to refund) the amounts of the First Use Tax paid by one or more pipelines for services or activities identified in the pipelines' submissions.

D.C. Circuit Remands FERC Approval of Pacific Alaska LNG Project and Point Conception Terminal Site to Consider New USGS Seismic Data

On 4/17/80 the U.S. Court of Appeals for the District of Columbia Circuit remanded an FERC order issued 10/12/79 (and another order dated 12/12/79 denying rehearing thereof but modifying in certain respects) which approved (1) the Pacific Alaska LNG Co. project (CP75-140 et al.), involving the transportation of LNG from the Cook Inlet area of southern Alaska to a receiving terminal to be built at Point Conception, California, and the sale of some 400,000 Mcf/d to Southern California Gas Co. and Pacific Gas & Electric Co.; and (2) the construction of the terminal at Point Conception for LNG to be transported from Alaska and imported from Indonesia pursuant to the Pacific Indonesia LNG Co. project (77-001-LNG). Petitions were filed in the D.C. Circuit for review of the 10/12 and 12/12/79 orders by Fred H. Bixby Ranch Co. and other parties. Fred H. Bixby Ranch Co. et al. v. FERC, Nos. 79-2248 et al.

In its 10/12/79 order, the Commission found a "pressing need" for additional long-term supplies to mitigate deepening curtailments in California gas service and especially to protect higher priority requirements; that there was no available alternative to the Pacific Alaska project; and that the Point Conception site was acceptable, based upon population density, cost, environmental impact and other factors specified in the Liquefied Natural Gas Terminal Act of 1977 passed by the State of California. Subsequently, Bixby and others filed motions to reopen the record to consider a seismic report prepared by the USGS and another status report submitted by the project sponsors on archaeological and seismic investigations then under way at the site. ~~In its 12/12/79 order, the FERC rejected the motions to reopen the record.~~ Said its prior order imposed on the project sponsors The Commission ~~noted that the project sponsors have, pursuant to the 10/12/79 order,~~ a continuing obligation to conduct seismic investigations at the Lompoc site and ~~and~~ report ~~on~~ the results thereof, ~~and~~ to submit their design plan for Commission review prior to commencement of construction. "To the extent that the project sponsors' ongoing seismic investigations generate new information and new issues, that information and those issues will be evaluated and resolved when the project sponsors complete their seismic investigations and submit their design plan based on those investigations." (See REPORT NOS. 1231, pp4-9; 1240, pp8-12.)

In its order, the D.C. Circuit remanded the case to the Commission in order to provide it "the opportunity to consider in the first instance new evidence presented by the U.S. Geological Survey report and any other relevant new information."

Also, the project sponsors are required

FERC Law Judge Holds that LNG Conversion Costs Should Be Borne by All Columbia Gas Customers; Rejects Columbia's Claim to Recover Post-Certificate Filing Expenses for Gas Arctic Project

On 3/26/80 FERC Administrative Law Judge Samual C. Gordon issued an initial decision concluding that most costs incurred by certain distributors to alleviate operational and utilization dislocations on the portions of their systems receiving revaporized LNG from Columbia Gas Transmission Corp. (RP78-20) at Cove Point, Maryland should be borne systemwide by all of Columbia Gas' customers because the increased supply benefitted the entire pipeline system. Because some distributors received LNG, the Law Judge said, others were able to acquire "more historic gas by displacement." At the same time, however, the burdens of this increased supply (other than the cost of LNG itself) were borne exclusively by the few distributors actually receiving the LNG -- primarily Washington Gas Light Co. and Baltimore Gas & Electric Co. -- while other distributors who benefitted from the increased supply incurred no LNG conversion costs. The Law Judge also concluded that Columbia Gas should not be permitted to recover its post-certificate filing expenditures for the Gas Arctic project to transport gas from the Prudhoe Bay to the Lower 48 States because of prior Commission policy that recovery of such costs for an unsuccessful supply project must be borne by the shareholders rather than the companies' customers.

The issues decided by the Law Judge were reserved in two settlements approved by the Commission on 7/3/79 involving increased rates proposed by Columbia Gas (RP78-20) and Columbia Gulf Transmission Co. (RP78-19). The settlements resolved all issues involving Columbia Gulf, and reserved the issues involving LNG conversion costs and the Gas Arctic expenditures by Columbia Gas.

The first issue arose by virture of claims by distributors receiving LNG from Columbia Gas -- principally WGL and BG&E -- that costs incurred in modifying and adjusting their systems to accommodate the LNG should be considered as part of Columbia Gas' system costs and be borne by all of Columbia Gas' distributors. The Law Judge explained that such modification was made necessary because of the differences in heating value and specific granting of Columbia Gas' "historic" gas from the southwest and the LNG. The former has a heating value of 1,010 Btu per cubic foot and a specific gravity of 0.576. By contrast, the vaporized LNG has a heating value of 1,120 per Btu per cubic foot and a specific gravity of 0.640. While recognizing that introduction of the LNG to its system could have an adverse impact on customers, Columbia Gas rejected alternatives -- including construction of a pipeline system or a stripping plant to remove ethane and heavier hydrocarbons -- as economically infeasible.

As noted, Judge Gordon concluded that the increase in supply resulting from the LNG purchase benefitted Columbia Gas' entire pipeline system. More gas was available for all of its distributors because those distributors not actually receiving LNG received more "historic" gas by displacement. In contrast, he continued, the burdens of the increased supply resulting from having to accommodate their systems because of the differences in heating value and specific gravity were borne only by those few distributors actually receiving the LNG -- primarily WGL and BG&E. Hence, "this proceeding presents an instance of undue discrimination, undue prejudice and undue preference and an unreasonable difference in service . . . ." To remedy this situation, the Law Judge decided that Columbia Gas must reimburse the distributors for those costs they properly incurred in accommodating the LNG. "Reimbursement will spread the costs of accommodating the LNG systemwide and ensure that all who receive the benefit of increased gas supply share fully and fairly the attendant burden."

The major portion of Judge Gordon's initial decision was devoted to a detailed discussion of the factual context in which various costs were incurred by WGL and BG&E to accommodate receipt of the LNG from Columbia Gas. The Law Judge found both distributors entitled to reimbursement of most costs which they claimed, including expenses for certain laboratory and research, appliance adjustment programs, saturn burner replacement programs, thermal billing, studies and tests to determine the impact of LNG upon a peakshaving plant, construction of a synthetic natural gas blending line, additional instrumentation and elimination of the heating value imbalances.

As to the method of reimbursement, Judge Gordon agreed with Staff's recommendation for a rate adjustment to reduce the revenue responsibility of those customers who are directly affected by deliveries of revaporized LNG, with the size of the revenue reduction equal to those costs actually incurred in accommodating the LNG. More specifically, the "reduced revenue responsibility" would be effectuated by crediting monthly invoices for the gas delivered by Columbia Gas to WGL and BG&E over a period of 12 months, with one-twelfth of the total amount of LNG conversion costs found to have been properly incurred. Columbia Gas is to treat the "reduced revenue responsibility" as an unrecovered purchased gas cost, and defer its recovery in the same manner as unrecovered purchased gas costs. Columbia Gas will also be permitted to recover carrying charges and both WGL and BG&E will be permitted to recover interest. The Law Judge rejected suggestions by the Peoples Counsel of Maryland and Columbia Gas for a lump sum payment or a one-time credit made on the eve of Columbia Gas' semi-annual PGA filing. The Law Judge could find no record evidence supporting those recommendations.

The Law Judge's conclusions only involve costs incurred through 3/31/79 because only evidence with respect thereto was available in this proceeding. Accordingly, he agreed with the concensus among all the parties that a Cost Verification Committee be established with respect to costs incurred subsequent to 3/31/79. "Service on the CVC should be voluntary and the CVC should be open to representatives from the Commission Staff, from Columbia, and from all Columbia's direct wholesale customers. The CVC should recommend to Columbia and the Commission those costs which it finds to have been properly incurred, applying the standards enunciated in this proceeding, and Columbia should file those costs with its next purchased gas adjustment filing."

The Law Judge also discussed the Commission's jurisdiction to resolve the LNG conversion cost issue. This issue arose, he noted, when the Ohio Public Utilities Commission argued that the FERC lacks jurisdiction to review costs incurred by local distributors. While local distributors are subject to state regulation and their rates are governed exclusively by state law, the rates in issue here are not rates of a local distributor, but those of Columbia Gas, a natural gas company subject to Commission jurisdiction. "We are concerned with Columbia and Columbia's rates; the rates of WGL, BG&E or any other distributor should not be, cannot be, and are not in issue . . . . Furthermore, 35 years of clear precedent establish the Commission's authority to consider admittedly nonjurisdictional activities, transactions and information in order to fulfill its jurisdictional functions."

Accordingly, Judge Gordon concluded that in exercising its jurisdiction to fix Columbia Gas' rates, the FERC may examine and consider LNG conversion costs incurred by those local distributors who purchase gas directly from Columbia Gas at wholesale for resale. However, he added, this does not apply to indirect customers -- i.e., those customers who receive their gas ultimately from Columbia Gas, but purchase it from someone other than Columbia Gas -- because they cannot seek rate relief directly from the Commission. "The relationship between such customers and

those from whom they purchase their gas traditionally has been the province of state regulation, remains so today, and should remain so in the future."

On the second reserved issue, Judge Gordon, as indicated, decided that Columbia Gas should not be authorized to recover its post-certificate filing expenditures for the Gas Arctic project, which was considered in the comparative hearing with the El Paso Alaska and Alcan projects (CP75-96 et al.) for construction of a pipeline to transport gas from the Prudhoe Bay. The President ultimately selected the Alcan proposal, and the Gas Arctic project is in the process of liquidation.

Columbia Gas sought to recover claimed expenditures totalling nearly $6.1 million applicable to its participation in the Gas Arctic/Northwest Pipeline Study Group made after the filing for a certificate by the Gas Arctic project. Such expenditures represented Columbia Gas' contributions to the Study Group from 4/1/74 through 2/28/78. Columbia Gas claimed those expenditures were prudently incurred for the benefit of all customers in order to make available a much needed new source of supply. Even though the competing Alcan project was selected, Columbia Gas contended its contributions to the Study Group were beneficial to Alcan, which has made use of much of the Study Group's engineering, environmental and other studies. And in this fashion, Columbia Gas said, its contributions will aid gas consumers and the gas industry generally. Moreover, its own customers will ultimately benefit from the Study Group's work since Columbia Gas has an option to purchase a certain amount of the Prudhoe Bay gas. Finally, Columbia Gas claimed that the Study Group's work was beneficial to the decisional process itself because the Gas Arctic project represented an alternative pipeline route which aided the decisionmakers in their evaluation and determination of the selected route.

First, the Law Judge said, the Gas Arctic project "was a failed or unsuccessful gas supply project and Columbia's contributions to the Study Group for the Gas Arctic project were, therefore, not used or useful to Columbia's customers in providing them service." In numerous past cases, he continued, the Commission has held -- based in large measure on a failure to meet the "used and useful" test -- that the risk of nonrecovery of preconstruction costs for an unsuccessful gas supply project must be borne by the applicant's shareholders rather than its customers, regardless of whether the costs were prudently incurred. Moreover, Judge Gordon continued, the President's decision selecting the Alcan project held that -- even for the successful applicant -- consumers and ratepayers shall not bear the risk of noncompletion. Hence, it would appear that Columbia Gas' customers and ratepayers should not bear the noncompletion risk of the disapproved project and the preconstruction costs therefor. "And clearly, Columbia should not be placed in a more advantageous position respecting preconstruction costs than the sponsors of the approved system."

The Law Judge also found that Columbia Gas failed to establish that the $6 million in claimed expenditures were used and useful to its customers or to the chosen Alcan system. While some of the Study Group's work may be of considerable value to Alaskan Northwest, there is no basis in the record to determine what part thereof would be beneficial. "There is insufficient evidence to allocate some portion of the $6 million as used and useful to Alaskan Northwest, U.S. gas consumers generally or Columbia's ratepayers in particular."

Judge Gordon also rejected the contention that prosecution of the Arctic Gas application, although rejected, aided the decisionmaking process. In the long history of the Commission, the Law Judge said, there have been numerous cases involving competing applications but Columbia Gas could cite no precedent where a similar argument was made or accepted. Also, Columbia Gas could not establish that one of

the alternatives which the decisionmakers would have had to consider would have been the proposed Gas Arctic project. Furthermore, since some portion of the Study Group's expenditures went to contest the Alcan proposal, the selection process was to a degree hindered and made more time consuming and costly by the efforts of the Study Group.

In conclusion, the Law Judge suggested that if the Commission desires to reexamine its policy placing the risk of loss of preconstruction expenditures for nonapproved, noncompleted or aborted gas supply projects on the shareholders rather than ratepayers of the unsuccessful applicant, it should do so in a generic proceeding or at least one in which all the unsuccessful applicants for the Alaskan transportation system would be parties.

FERC Standardizes Format of Briefs on Exceptions and Briefs Opposing Exceptions

On 4/21/80 the FERC issued Order No. 77 (RM80-51) amending Section 1.31(b) of the Commission's Rules and Practice and Procedure to standardize the format of briefs on exceptions and briefs opposing exceptions. The purpose of the amendment -- which will apply to briefs submitted 6/20/80 and thereafter -- is to facilitate Commission review of legal, factual and policy issues presented to it for decision.

The amendment requires that each brief on exceptions and brief opposing exceptions include (1) a discussion of the brief writer's arguments, together with references to the pages of the record or exhibits containing evidence in support of such arguments; and (2) a separate summary of the brief, not more than five pages in length. There is no prescribed format for this summary.

In addition, briefs on exceptions must include a short statement of the case, a list of the errors of fact or law asserted, and a concise discussion of the policy considerations that warrant Commission review. Briefs opposing exceptions must include a list of the exceptions that are being opposed and a rebuttal to the policy considerations claimed to warrant Commission review.

Briefs on exceptions or opposing exceptions not in compliance with the above amendment will be subject to rejection or nonconsideration by the Commission.