TRANSCANADA PIPELINES LIMITED

BUSINESS AND SERVICES RESTRUCTURING AND MAINLINE 2012 – 2013 TOLLS APPLICATION

WRITTEN EVIDENCE OF DENA WIGGINS

(Ballard Spahr LLP)

March 9, 2012

NATIONAL ENERGY BOARD

IN THE MATTER OF the national Energy Board Act, R.S.C. 1985, c N-7, as amended, and the Regulations made thereunder;

AND IN THE MATTER OF an Application for (1) approval required to implement a Restructuring Proposal that affects the businesses and services of TransCanada PipeLines Limited, NOVA Gas Transmission Ltd. and Foothills Pipe Lines Ltd., and (2) approvals of final tolls for the TransCanada Mainline for 2012 and 2013.

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TABLE OF CONTENTS

I. INTRODUCTION

Q1. Please state your name, address and position.

A1. My name is Dena E. Wiggins. I am a Partner in Ballard Spahr LLP, a law firm in the United States with offices in Atlanta, Baltimore, Bethesda, Denver, Las Vegas, Los Angeles, New Jersey, Philadelphia, Phoenix, Salt Lake City, San Diego, Washington D.C., and Wilmington. My office is located at 601 13th St., N.W., Washington, D.C. 20005 (until April 27, 2012, after which date my office will relocate to 1909 K St., N.W., Washington, D.C. 20006).

Q2. Please describe briefly your educational background and professional qualifications?

A2. I am a U.S. attorney specializing in energy regulations and policy. My practice focuses on the policies and regulation of natural gas pipeline transportation. I received a *Juris Doctor* from the Georgetown University Law Center and a B.A., *magna cum laude*, from the University of Richmond. I have more than 20 years of experience working on energy regulatory and legislative matters before regulatory agencies and the U.S. Congress. I have participated in numerous natural gas pipeline rate proceedings and in rulemakings affecting the U.S. Federal Energy Regulatory Commission's ("FERC" or "Commission") regulation of natural gas. My experience involves virtually every significant rulemaking effort over the past 20 years, including the restructuring of the natural gas industry and the first fully litigated oil/products pipeline case after the enactment of the Energy Policy Act of 1992.

I have also been involved in many legislative matters, including the passage of the Energy Policy Acts of 1992 and 2005, the decontrol of wellhead prices of natural gas, as well as efforts to increase energy exploration and production. I regularly speak on natural gas policy issues and I have testified before FERC on natural gas policy matters.

I am a member and past Board Member of the Energy Bar Association, and past Co-chair of its Program Committee. I am also a member of the American Bar Association where I have chaired and vice-chaired a number of committees related to public utilities. Further, I am the past Chair of the Industrial Working Group of the National Petroleum Council, and a member of the British American Business Association's Energy Committee. Furthermore, I am the natural gas counsel for the Process Gas Consumers Group, the Independent Petroleum Association of America and the American Forest & Paper Association. In addition, I regularly provide advice to a variety of clients on natural gas regulatory matters as well as FERC compliance and enforcement matters. I was named Top Utility Lawyer for Natural Gas Policy and Regulation, by Public Utilities Fortnightly, 2011. I was also named to Chambers USA: America's Leading Lawyers for Business, energy: oil & gas, regulatory and litigation (national ranking), 2010-2011, and to The Best Lawyers in America, energy law and natural resources law, 2006-2012.

Q3. Who is sponsoring your evidence in this proceeding?

A3. I am providing evidence on behalf of the Industrial Gas Users Association ("IGUA").

II. SCOPE OF EVIDENCE

Q4. What is the purpose of your testimony?

A4. The purpose of this testimony is to explore various approaches in U.S. case law and precedent that may be available to the National Energy Board ("NEB" or "Board") as it considers how to set rates on TransCanada PipeLines Limited's ("TransCanada" or "TCPL") system. In particular, I provide evidence regarding the "used and useful" principle as it has been applied in U.S. case law and precedent as well as various approaches grounded in U.S. case law to respond to changes in the regulatory structure, general market changes, failed projects, abandoned assets, turned back capacity and other events that have rendered regulated assets unused and unuseful and/or underutilized.

Q5. Are you presenting legal theories related to the concept of "prudency" and "prudently incurred costs" in ratemaking?

A5. My evidence does not focus on, and does not need to focus on, the concept of prudency.

Q6. Please explain.

A6. It is my understanding that "prudency" is not at issue in this proceeding. It is also my understanding that IGUA is not challenging the prudency of any investments that TransCanada has made in the past and that have been properly approved by the Board. Rather, IGUA is focused on situations where, although prudency is not in question, changes in market circumstances render assets no longer "used and useful" or render regulated assets significantly underutilized.

Thus, the focus of my evidence is on U.S. precedent in which U.S. regulators, when faced with situations in which assets are no longer used and useful and/or are underutilized, have crafted regulatory solutions that weigh the resulting cost burden on the regulated entity, its shareholders and the customers and have arrived at appropriate solutions to apportion this burden.

Prudency is somewhat of a backward looking concept, whereas the concepts and possible solutions that I focus on are forward looking to resolve cost-recovery and rate issues, while at the same time, refraining from assigning "blame."

Q7. Are you presenting evidence related to precedent in Canadian law?

A7. No, I am not. I am a lawyer in the U.S. and thus, my evidence focuses on U.S. regulatory policies, case law, and precedent.

Q8. What relevance could U.S. law have to a proceeding pending in Canada?

A8. It is my understanding that IGUA believes that U.S. precedent can provide guidance to the parties in this case, as well as the NEB, regarding how to structure a forward-looking and hopefully permanent solution to the difficult ratemaking problems associated with TCPL's underutilized mainline.

In addition, as a conceptual matter, TCPL has agreed that it must share the burden of underutilization on its system.[1] Furthermore, TCPL's reliance on U.S. precedent[2] in supporting its Application for Approval of the Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013, Hearing Order RH-003-2011 ("Application" or "Restructuring Proposal"), makes this exploration of relevant U.S. solutions particularly appropriate. Specifically, TCPL has discussed a "form of cost recovery [that] has been used frequently in the U.S. and in Ontario for stranded generation costs, and for above-market purchased gas costs and purchased power costs" and has suggested that this form of cost recovery is relevant to the Restructuring Proposal.[3] This fact is particularly meaningful because, as explained more fully below, U.S. cases related to stranded generation costs and above-market purchased gas costs require investors to share a significant portion of these costs.

Additionally, TCPL agrees that the NEB is not "precluded . . . from changing the methodology under which the Mainline recovers its costs"[4] in order to disallow recovery of a portion of the "return on and of capital on [its] investments . . .

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1 *See, e.g.*, TransCanada's Responses to Round 1 Information Requests, Page 1 of Response to IGCAA 5.3 ("The costs and risk of [TransCanada's Application for Approval of the Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013, Hearing Order RH-003-2011 ("Application" or "Restructuring Proposal")] as well as its intended benefits are proposed to be shared among a broad cross-section of stakeholders, including TransCanada.") [Please note that copies of the cases and materials cited in my evidence are provided in the Appendix.]

2 *See generally*, Application, Section 4.0, Pages 1 thru 20; *see also id.* at notes 34 and 39; *see also* TransCanada's Responses to Round 1 Information Requests, Response to IGUA 1.3.

3 *See* TransCanada's Responses to Round 1 Information Requests, Page 4 of 10 of Response to NEB 1.1(a).

4 TransCanada's Responses to Round 1 Information Requests, Page 3 of Response to NEB 2.43(d).

through a cost of service methodology."[5] Thus, an exploration of possible alternative cost recovery methodologies is appropriate.

Q9. Does your evidence discuss every case in the U.S. that has addressed the concept of "used and useful" or other related regulatory solutions to unused or underutilitzed regulatory assets?

A9. No, an exhaustive compendium of U.S. case law is beyond the scope of this evidence. Rather, I have tried to provide a summary of key approaches that address these complex issues, with a particular focus on cases decided by FERC related to interstate natural gas pipelines.

Q10. What is the Federal Energy Regulatory Commission or FERC?

A10. In general, FERC is an independent federal regulatory agency in the United States, charged with the statutory responsibility of overseeing the implementation of the Natural Gas Act of 1938 and ensuring that interstate natural gas pipeline rates are "just and reasonable." FERC also has jurisdiction over electricity transmission rates, interstate oil and product pipeline rates as well as certain hydropower projects.

Q11. Are you presenting evidence on the impact of the "regulatory compact" on the matters at issue in this case?

A11. No.

Q12. Are you familiar with the term "regulatory compact" as it has been used in this case?

A12. I am aware that TransCanada has used that term in this proceeding although it is rarely used in interstate natural gas pipeline proceedings in the U.S. In fact, to my knowledge it is not a term that has been adopted by FERC to refer to the

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[5] *Id.*

framework of regulations governing interstate natural gas pipelines or the regulatory relationship between FERC and the interstate natural gas pipelines.

Q13. What is your understanding of what TransCanada means when it uses the term "regulatory compact"?

A13. In general, TransCanada seems to imply that the NEB is constrained by the so-called "regulatory compact" from disallowing a return on any prudently incurred rate base assets.[6]

Q14. Do you agree with this contention?

A14. Although I cannot speak to Canadian law on this subject, federal policy in the United States takes a different approach.

Q15. Please explain.

A15. In general, federal U.S. policy for interstate natural gas pipelines makes a distinction between the concept of prudency and the "used and useful" concept. The prudent-investment test permits the regulated entity to recover, through its allowed rates, the historical cost of its investments, provided that they were prudent when made.[7] As I said before, the standard of "prudency" is generally backward-looking and the standard of "used-and-useful" is generally forward-looking.[8]

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6 *See, e.g.,* TransCanada's Responses to Round 1 Information Requests, Page 2 of Response to NEB 1.1 ("[TransCanada's] interpretation of the phrase 'the historical regulatory compact', which TransCanada believes requires that the Board establish tolls that provide TransCanada with an opportunity to earn a reasonable return on its prudently-incurred investment and to recover its investment over a reasonable period of time."); *see also id.* ("TransCanada firmly believes the fundamental tenet that regulated utilities should be provided with a reasonable opportunity to recover their prudently-incurred costs must continue to be respected.").

7 William J. Baumol and J. Gregory Sidak, *The Pig In The Python: Is Lumpy Capacity Investment Used And Useful?* 23 Energy L. J. 383, 384 (2002).

8 *Id.* at 383.

A prudency challenge to a rate base item could, for example, analyze whether the investment in the asset was proper at the time the investment was made. This evidence is not focused on the legal precedent in the U.S. analyzing the rationale for challenging the rate base treatment of assets or challenging any form of cost-recovery in rates based on an analysis of the prudency of the initial investment decision. Rather, and regardless of the prudency of the original investment decision or decisions, in the U.S. the parties and the regulators may look "forward" to ascertain whether these assets remain "used and useful" for purposes of calculating rates on a going-forward basis. Even if investment decisions in the past may have been prudent at the time they were made, U.S. federal policy does not require that the regulated entity is entitled to continue to recover the costs associated with these assets year after year, rate case after rate case.

In fact, it would be contrary to the fundamental principles of ratemaking to continue to force shippers to pay in rates costs associated with assets that are no longer "used and useful" for the purpose of providing pipeline transportation service.[9]

Q16. Is the term "regulatory compact" used at all in the United States?

A16. The concept of the "regulatory compact" has been considered in the U.S. in the context of electricity market deregulation and related stranded costs. In James W. Boyd, The Regulatory Compact And Implicit Contracts: Should Stranded Costs Be Recoverable?,[10] likening the regulatory compact to an implicit contract, the author asserts that, although deregulation in the electricity markets was a mandated regulatory change, recovery of stranded costs should occur in only a

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9 Also, from a more general standpoint, losses incurred in the unprofitable operation of a utility's business may not be recovered from customers. *See Re Pacific Tel. & Tel. Co.*, 23 PUB. UTIL. REP. 3d (PUR) 209 (Cal. Pub. Util. Comm'n 1958); *Re Arkansas Power & Light Co.*, 13 PUB. UTIL. REP. 3d (PUR) 1. Further, the operation of a public utility involves risks and controls that must generally be shared equally by investors and consumers. *See Re Boston Edison Co.*, 46 PUB. UTIL REP. 4th (PUR) 431, *appeal aff'd*, *Attorney General v. Department of Public Utilities*, 390 Mass. Adv. Sheets 208, 455 N.E.2d 414 (1983).

10 RFF Discussion Paper 97-01, October 1996 (Resources for the Future, 1996) (*hereinafter* "Boyd"), *available at* http://www.rff.org/RFF/Documents/RFF-DP-97-01.pdf.

proscribed set of circumstances and that, when called for, compensation should be partial, rather than full.[11]

Boyd asserts that, in considering whether utilities are entitled to recovery under the "regulatory compact," it is necessary to assign the "liability for costs to the party best able to reduce the likelihood of a negative contingency arising."[12] Given that "contracts are designed to allocate liability for future contingencies to the parties who can adapt to or insure against them at least cost, . . . the ability . . . to predict contingencies . . . [and the] ability to alter investment decisions to reflect changed external conditions . . . suggest that utilities should bear the cost of changed conditions."[13] In addition, "the scale and corporate nature of utilities suggests that they can adequately insure against the risks posed by change."[14]

In fact, U.S. legal precedent does *not* show a "legal guarantee to cost recovery."[15] The U.S. Supreme Court's ruling in *Duquesne Light Co. v. Barasch*,[16] (which is explored in more detail below), "held that broad discretion is left to the states to determine their own rules for cost recovery and affirmed that failure to recover costs, even for a 'prudent' investment, is not evidence of a taking."[17] The Court specifically held that a "state scheme of utility regulation does not 'take' property simply because it disallows recovery of capital investments that are not 'used and useful in service to the public.'"[18] Therefore, *Duquesne* "reminds utilities that cost recovery is not federally guaranteed – thus undermining the argument that recovery is implicit in the regulator-utility relationship."[19] As a result, the

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11 Boyd at 3.

12 *Id.*

13 *Id.* at 14.

14 *Id.* at 15.

15 *Id.* at 9.

16 488 U.S. 299 (1989) ("*Duquesne*").

17 Boyd at 9.

18 *Duquesne* at 302.

19 Boyd at 12.

"regulatory compact" as used in the U.S. in the electricity market context does *not* assume cost recovery by default.[20]

In fact, TCPL appears to agree that this is also the case in Canada with regard to the NEB's regulations of natural gas pipelines. TCPL has stated as follows: "The argument that failure to permit recoupment of prudently incurred costs would violate the regulatory compact is *not* based on *any* Canadian precedents."[21]

III. SUMMARY

Q17. Can you please summarize your testimony?

A17. As I mentioned earlier, this evidence explores the "used and useful" principle and the various applications of this principles in the context of the U.S. regulatory framework. A strict application of this principle requires that only costs related to assets that are used and useful are included for purposes of deriving rates, however, U.S. regulators have departed from a strict application of this principle in a variety of circumstances. In particular, regulators have grappled with circumstances in which assets have been rendered no longer "used and useful" due to changes in the regulatory structure mandated by the regulators. In addition, regulators have also grappled with the appropriate ratemaking response to changes in the market that have, in turn, lead to certain assets being no longer "used or useful" or underutilized. Regulators have also grappled with the appropriate ratemaking treatment of costs related to failed projects, assets that are currently not used but may be returned to service at a later date, as well as costs related to failed or abandoned projects. This evidence explores the regulatory responses to these situations, with particular emphasis on FERC's approaches in the context of interstate natural gas pipeline ratemaking.

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20 *Id.* at 17.

21 TransCanada's Responses to Round 1 Information Requests, Page 4 of Response to Gaz Metro 11.5 (emphasis added).

Q18. Does your evidence also discuss the various regulatory solutions to these scenarios?

A18. Yes. In general, although there are a variety of specific solutions that have been crafted by both federal and state regulators, many solutions adopt a cost-sharing approach in which the costs associated with assets that are no longer used and useful or otherwise underutilized are shared between the regulated entity (and its shareholders) and the customers of the regulated entity.

IV. THE LEGAL FOUNDATION

Q19. Before discussing the FERC case law and other relevant precedent, can you please provide a general definition of "used and useful?"

A19. Yes, in general, a regulated entity, such as a utility or a pipeline, is allowed to recover costs related to assets that are both used and useful in providing service. The distinction between "used" and "useful" may be reasonably interpreted as being between investments that do not provide physical services (not used) and those that, while providing physical services, are superfluous (not useful).[22] The corollary is that, if assets are not "used and useful," the costs associated with these assets are excluded from rates.

Q20. What is the legal precedent for the "used and useful" standard?

A20. The "used and useful" standard derives from the Supreme Court's opinion in *Smyth v. Ames*.[23] In *Smyth*,

> the Supreme Court articulated the guiding principle that "the basis of all calculations as to the reasonableness of rates to be charged by a [public utility] must be the fair value of the property *being used by it for the convenience of the public*." [*Smyth*, 169 U.S. at

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22 *See* Jonathan A. Lesser, *The Used And Useful Test: Implications For A Restructured Electric Industry*, 23 Energy L. J. 349, 352 (2002) (*hereinafter* "Lesser") citing *Denver Union Stockyard Co. v. United States*, 304 U.S. 470 (1938).

23 169 U.S. 466, 42 L. Ed. 819, 18 S. Ct. 418 (1898) ("*Smyth*").

> 546 (emphasis added).] Although methods for determining values of rate base items have evolved since *Smyth v. Ames*, the precept endures that an item may be included in a rate base only when it is "used and useful" in providing service. In other words, current rate payers should bear only legitimate costs of providing service to them. The [Federal Power Commission, FERC's predecessor,] early adopted the "used and useful" standard and has not departed from it without careful consideration of the wisdom of requiring current rate payers to bear costs of providing future service.[24]

Smyth held that the U.S. Constitution required regulators to accord railroads a return for the value of the assets that were "used and useful" in providing services. The Court reasoned that otherwise, rates would be confiscatory. The Court specified six measures of value and a number of methodologies for determining whether the rates charged by a corporation represented the fair value of the property being used by it for the convenience of the public. The court listed these measures as follows:

> in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case.[25]

Thus, as I said earlier, the distinction between "used" and "useful" is between investments that do not provide physical services (not used) and those that, while providing physical services, are superfluous (not useful).[26] The general principle is that costs related to an asset or related to expenditures for an item may be included in a public utility's rates when the asset or item is "used and useful" in

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24 *Tennessee Gas Pipeline Co. v. FERC*, 196 U.S. App. D.C. 187, 606 F.2d 1094, 1109 (D.C. Cir. 1979) (footnotes omitted), *cert. denied*, 445 U.S. 920, 100 S. Ct. 1284, 63 L. Ed. 2d 605 and 447 U.S. 922, 100 S. Ct. 3012, 65 L. Ed. 2d 1113 (1980). *See also, Natural Gas Pipeline Company of America v. FERC*, 765 F.2d 1155, 1157 (D.C. Cir. 1985).

25 *Smyth,* 169 U.S. at 546-47.

26 *See* Lesser at 352 (citing *Denver Union Stockyard Co. v. United States,* 304 U.S. 470 (1938)).

providing service.[27] For example, it may be argued that a surplus of new generating capacity in the face of declining customer demand would be unuseful and therefore should be excluded from rates.[28]

In the *Duquesne* case mentioned above, the U.S. Supreme Court decided on the constitutionality of a Pennsylvania statute providing that a utility's cost of construction of a generating facility may not be made part of a rate base, nor otherwise included in rates charged, until such time as the facility "is used and useful in service to the public." The court held that the statute is constitutional because it simply disallows recovery of capital investments that are not "used and useful in service to the public." Further, the Court provided an overview of ratemaking principles as follows:

> The guiding principle has been that the Constitution protects utilities from being limited to a charge for their property serving the public which is so "unjust" as to be confiscatory. . . If the rate does not afford sufficient compensation, the State has taken the use of utility property without paying just compensation and so violated the Fifth and Fourteenth Amendments. As has been observed, however, "[h]ow such compensation may be ascertained, and what are the necessary elements in such an inquiry, will always be an embarrassing question." *Smyth v. Ames*, 169 U.S. 466, 546 (1898). *See also Permian Basin Area Rate Cases*, 390 U.S. 747, 790 (1968) ("[N]either law nor economics has yet devised generally accepted standards for the evaluation of rate-making orders").
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> . . . [I]n the landmark case of *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), this Court abandoned the rule of *Smyth v. Ames*, and held that the "fair value" rule is not the only constitutionally acceptable method of fixing utility rates. In *Hope* we ruled that historical cost was a valid basis on which to calculate utility compensation. 320 U.S., at 605 ("Rates which enable [a] company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risk assumed certainly cannot be condemned as invalid, even though they might

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27 *See NEPCO Municipal Rate Committee v. FERC*, 668 F.2d 1327, 1333, 215 U.S. App. D.C. 295 (D.C. Cir. 1981).

28 *See* Lesser at 352.

> produce only a meager return on the so called 'fair value' rate base").[29]

The Court went on to reason that the "used and useful" statute would only have a slight effect on the actual utility rates involved and that "[n]o argument has been made that these slightly reduced rates jeopardize the financial integrity of the companies, either by leaving them insufficient operating capital or by impeding their ability to raise future capital."[30]

Q21. Does TransCanada acknowledge the applicability of a "used and useful" test for proper calculation of its rates?

A21. Yes, TransCanada seems to agree that in "determining whether the capacity is used and useful,"[31] "[i]f there is no current use of an asset, for firm or non-firm service, then the regulator should consider whether the asset is available for service and, if it is, it should consider whether the asset is likely to be needed for service in the reasonably foreseeable future."[32]

Q22. Does TransCanada comment on FERC's application of the used and useful test for determining interstate pipeline rates?

A22. Yes, however, in my view, TransCanada mischaracterizes FERC's role in considering the "used and useful" principle. TransCanada states as follows: "TransCanada understands that the FERC has the discretion but not the obligation to employ the 'used and useful' standard to rate base or cost of service."[33] In fact, given a multitude of court precedents, FERC is required to consider the "used and usefulness" of pipeline assets when exercising its authority to approve just and

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29 *Duquesne*, at 307-310 (footnotes omitted).

30 *Id.* at 312.

31 Round 1 Information Requests, APPrO 98(d).

32 TransCanada's Responses to Round 1 Information Requests, Page 2 of Response to APPrO 98(d).

33 TransCanada's Responses to Round 1 Information Requests, IGUA Part A, Page 4 of response to IGUA 1.3, Request (l).

reasonable rates because, as emphasized by the courts, "an item may be included in a rate base *only* when it is 'used and useful' in providing service."[34]

V. FERC'S RELIANCE ON THE "USED AND USEFUL" PRINCIPLE

Q23. Has FERC relied on the "used and useful" principle in carrying out its responsibilities to regulate interstate natural gas pipelines?

A23. Yes. FERC has emphasized that "[t]he 'used and useful' principle prohibits pipelines from including in rate base the cost of assets that are not used or useful in providing service."[35] Moreover, FERC must ensure that the rate is "'just and reasonable' to *both* consumers and investors"[36] and must engage in "a reasonable balancing, based on factual findings, of the investor interest in maintaining financial integrity and access to capital markets and the consumer interest in being charged non-exploitative rates."[37]

Q24. In general, what happens when assets that have been used and useful and therefore included in rate base, are no longer "used and useful"?

A24. As I stated earlier, if only costs related to assets that are used and useful in providing regulated services are to be included in rate base, then it follows that costs related to these assets must be removed from rate base if the assets become no longer used and useful.

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34 *Tennessee Gas Pipeline Co. v. FERC*, 606 F.2d 1094, 1109 (D.C. Cir. 1979) (emphasis added).

35 *El Paso Natural Gas Company*, 134 FERC ¶ 63,002 at P 35 (2011). However, FERC has used a more liberal interpretation of "used and useful" in specific situations such as construction work in progress, research and development, and advance payments. *See Transcontinental Gas Pipe Line Corporation*, Opinion No. 801-A, 59 F.P.C. 1237 at n.3 (1977).

36 *Jersey Cent. Power & Light Co. v. Federal Energy Regulatory Com.*, 810 F.2d 1168, 1172 (D.C. Cir. 1987) (emphasis added). The court noted that "placing prudent investments in the rate base would seem a more sensible policy than a strict application of 'used and useful,' for under this approach it is the investment, and not the property used, which is viewed as having been taken by the public." *Id.* at 1181.

37 *Id.* at 1178.

Q25. Has FERC followed this general principle?

A25. As explained in more detail below, if facilities are abandoned, FERC has required that the costs associated with these facilities be removed from rate base. In addition, FERC has disallowed cost recovery related to failed projects and failed supply projects. However, FERC has considered the application of the "used and useful" principle in a range of circumstances and has departed from a strict application of this principle. For example, and as discussed in detail below, FERC makes a distinction between assets rendered no longer used and useful due to regulatory changes as compared to assets rendered no longer used and useful due to market changes. Further, in situations involving market changes that render assets no longer used and useful or significantly under-utilized, FERC has generally adopted some type of cost sharing approach in which the pipeline (and its shareholders) and their customers share in bearing the cost burden associated with these assets.

A. <u>FERC Mandated Regulatory Changes and "Used and Useful"</u>

Q26. You mentioned that FERC draws a distinction between assets rendered no longer used and useful due to regulatory changes versus assets rendered no longer used and useful due to market changes. Can you please explain further?

A26. In general, FERC allows a pipeline to recover the full amount of expenses or investments that the pipeline incurs due to changes in the regulatory structure mandated by FERC. On the other hand, FERC generally requires some sort of cost-sharing whereby the pipeline (and its shareholders) share in the resolution along with the ratepayers when market conditions change.

Q27. Please provide an example of a FERC-mandated change in the regulatory structure.

A27. In 1992, in Order No. 636, FERC mandated that interstate natural gas pipelines exit the merchant function of selling natural gas and henceforth only provide transportation and transportation related services. One of the many issues that faced the pipeline industry and that also faced the Commission was the appropriate rate treatment afforded the pipelines related to costs already incurred to secure and provide supplies of natural gas to their customers.

Q28. How did FERC respond to this problem?

A28. In the context of Order No. 636, FERC found that

> the Commission's regulatory actions in Order No. 636 have caused the pipelines to incur the Gas Supply Realignment (GSR) costs and rendered the underlying gas supply contracts *no longer used and useful*. In these circumstances, traditional ratemaking principles require the Commission to allow the pipelines an opportunity to recover the full amount of the expenses caused by its actions.[38]

In fact, FERC allowed pipelines an opportunity to recover a total of 4 types of expenses, including GSR, caused by its "regulatory actions in Order No. 636." FERC stated:

> The Commission recognizes that pipelines will likely incur costs as a result of implementing the requirements of this rule. The issues are how, to what extent, and from whom, should the pipelines recover those costs.
>
> The Commission envisions four types of costs. The first type are the unrecovered gas costs (or credits) remaining in the purchased gas adjustment (PGA) Account No. 191 when a pipeline adopts market-based pricing for its gas sales and terminates its purchased gas adjustment mechanism (the "Account No. 191 balance"). The second type of costs may result from the pipelines realigning their existing gas supply contracts with producers in connection with implementing this rule ("[GSR] costs"). A third type are the costs of a pipeline's assets now used to provide bundled sales service, such as gas in storage, and capacity on upstream pipelines, that cannot be directly assigned to customers of the unbundled services ("stranded costs"). A fourth type consists of costs associated with

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[38] Order No. 636-C at pp. 61,788-61,789 (emphasis added).

> physically implementing the rule (*e.g.*, meters, valves, communications equipment)("new facility costs").[39]

For example, the costs associated with the "capacity on upstream pipelines" in Account No. 858 were generally recovered through surcharges on pipeline rates.[40]

B. <u>FERC's Ratemaking Response to Market Changes in the Context of the "Used and Useful" Analysis</u>

Q29. Please provide an example where FERC decided that changes in the market, rather than FERC-mandated regulatory changes, caused the pipelines to incur costs that were recovered through a cost-sharing approach.

A29. In Order Nos. 500 and 528, FERC decided to spread the costs of pipeline take-or-pay settlements between the pipelines and other segments of the industry.

Q30. What are take-or-pay clauses in natural gas purchase contracts?

A30. Take-or-pay clauses are contract provisions under which natural gas pipelines, as the purchasers of natural gas, were obligated to either "take" (and pay) for natural gas from producers or pay either the full contract price or some large percentage thereof even if the purchaser was not able to "take" physical delivery of the natural gas. These agreements arose out of the high natural gas prices of the late 1970's and early 1980's. At that time, pipelines expected that demand would continue at high levels and even increase. Therefore, pipelines entered into long-term contracts to purchase gas supplies at high prices subject to high take-or-pay requirements.

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39 Order No. 636 at p. 30,457.

40 *See, e.g., Tennessee Gas Pipeline Company*, 64 FERC ¶61,020 at p. 61,294 (1993) ("consistent with our decision in Order No. 636 Account No. 858 costs are stranded costs that will be recovered from all firm open access shippers.")

Q31. Can you please explain the background of the take-or-pay agreements?

A31. Yes. Initially, pipelines were "permitted to include take or pay prepayments in Account 165, and they were allowed rate base treatment over a period no longer than five years. By including these amounts in the rate base, pipelines were allowed a return and associated taxes on such amounts."[41] Pipelines often made "prepayments" in order to avoid taking the gas as well as avoid paying a penalty. These prepayments were made under the expectation that the pipelines would be able to take the gas at a later date. However, after five years, "the pipelines [generally] forfeited . . . any right to take the gas for which prepayments were made."[42]

Although FERC generally did not *pre-approve* the pipelines' entering into these take-or-pay agreements, it has generally allowed the costs associated with these agreements to be part of its Uniform System of Accounts.[43]

Q32. What happened to these contracts that included take-or-pay provisions?

A32. The interstate pipelines' problems with these take-or-pay clauses arose in the 1980's and as FERC later determined, were caused by "general market conditions"[44] and "market distortions."[45] As FERC explained:

> The artificially high prices of the late 1970's and early 1980's caused producers to increase greatly their exploration and drilling for new gas supplies. By 1981, new additions to gas reserves actually exceeded current production, having averaged only 46 percent of current production during the 10 years preceding enactment of the NGPA. At the same time, pipelines, expecting demand to continue at high levels and even increase, and recalling

[41] *Take or Pay Provisions in Gas Purchase Contracts*, 47 Fed. Reg. 57268 (Dec. 23, 1982) (Statement of Policy), FERC Statutes and Regulations ¶30,410 at p. 30,313, Docket No. PL83-1-000 (Dec. 16, 1982) (*hereinafter* "1982 Policy Statement").

[42] Oder No. 500-H at p. 31,523.

[43] *See*, 18 CFR Part 201.

[44] Order No. 636-C at p. 61,785 *citing* Order No. 528-A at pp. 61,303-5.

[45] Oder No. 500-H at p. 31,509.

> their recent experience with curtailments, continued to enter into long-term contracts to purchase additional gas supplies at high prices and subject to high take-or-pay requirements.
>
> However, by 1982, demand for gas was falling. High natural gas prices, combined with decreasing oil prices, led to increased fuel switching, particularly as customers who did not already have the necessary equipment to burn alternative fuels installed it. The recession of the early 1980's and warmer than normal weather further decreased demand. These factors combined to create an excess of the supply of natural gas (*i.e.*, current deliverability from the nation's gas wells) over the demand for natural gas.[46]

Over time, it became clear that the pipelines needed to try to renegotiate or otherwise reform these contracts. In many instances, pipelines did so by either "buying out" or "buying down" these natural gas supply contracts. Ultimately, as discussed further below, when FERC was confronted with the issue of whether to allow the pipelines to recover these costs from their ratepayers, FERC recognized that it was difficult to assign blame for this problem and decided that all segments of the natural gas industry should shoulder some of this burden, including pipeline investors.

Q33. Can you please explain how FERC addressed the take-or-pay issue?

A33. In its 1982 Policy Statement, FERC stated:

> Recognizing that take-or-pay contract obligations may be shielding the prices of deregulated and other higher cost gas from market constraints, the Commission is announcing its general policy . . . regarding prepayments for natural gas pursuant to take or pay provisions in gas contracts and amendments thereto between producers and interstate pipelines which become effective December 23, 1982. With respect to such contracts, the Commission intends to apply a rebuttable presumption in general rate cases that prepayments to producers will not be given rate base treatment if the prepayments are made pursuant to take or pay

[46] Order No. 500-H at pp. 31,509-10 (footnotes omitted).

> requirements in such gas contracts or amendments which exceed 75 percent of annual deliverability.[47]

FERC also addressed the regulatory treatment of buy-out costs of take-or-pay obligations, and "establish[ed] a policy with regard to the buy-out of contractual take-or-pay obligations of natural gas pipelines, and how those costs are to be treated in future rate cases."[48]

FERC's cost-sharing policy with regard to take-or-pay agreements became clear in Order No. 500.[49]

Q34. Can you explain FERC's actions in Order No. 500?

A34. Yes, but first I would like to point out that, in formulating a solution to the take-or-pay contract problem, FERC likened the situation to a "failed supply project." In particular, FERC relied on *Natural Gas Pipeline Company of America v. FERC*, 765 F.2d 1155 (D.C. Cir. 1985) ("*NGPL I*"), where the Court of Appeals for the D.C. Circuit held that the pipeline should not be allowed to recover its costs related to failed supply projects even though its expenses were made prudently. I will discuss this case and the line of cases addressing failed supply projects further in this evidence, but wanted to establish the legal precedent for FERC's approach.

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47 1982 Policy Statement at p. 30,310 (Summary).

48 *Regulatory Treatment of Payments Made in Lieu of Take-or-Pay Obligations*, 50 Fed. Reg. 16076 (Apr. 24, 1985) (Statement of Policy and Interpretative Rule), *FERC Statutes and Regulations* ¶30,637 at pp. 31,299-300, Docket No. PL85-1-000 (Apr. 10, 1985).

49 *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, 52 Fed. Reg. 30,334 (Aug. 14, 1987) (Interim Rule), *FERC Statutes and Regulations*¶30,761, *extension granted;* Order No. 500-A , *FERC Statutes and Regulations*¶30,770 , *modified*, Order No. 500-B, *FERC Statutes and Regulations*¶30,772 , *modified further*, Order No. 500-C, *FERC Statutes and Regulations*¶30,786 (1987), *modified further*, Order No. 500-D , *FERC Statutes and Regulations*, ¶30,800, *reh'g denied*, Order No. 500-E, 43 FERC ¶61,234, *modified further*, Order No. 500-F, *FERC Statutes and Regulations*¶30,841 (1988), *reh'g denied*, Order No. 500-G, 46 FERC 61,148 (1989), *American Gas Association v. FERC*, 888 F.2d 136 (D.C. Cir. 1989) (remanding interim rule), Order No. 500-H, *FERC Statutes and Regulations*¶30,867 (1989) (Final Rule), *modified*, Order No. 500-I, *FERC Statutes and Regulations*¶30,880 (1990), *aff'd in part & remanded in part*, *American Gas Association v. FERC*, 912 F.2d 1496 (D.C. Cir. 1990).

Q35. Please continue to explain Order No. 500.

A35. Specifically:

> In the Order No. 500 policy statement concerning the passthrough of pipelines' take-or-pay settlement costs, the Commission adopted two acceptable passthrough mechanisms. Under the basic mechanism, permitted for all pipelines, a pipeline may include all prudently incurred settlement costs in its commodity rates. This basic mechanism is consistent with the Commission's longstanding policy that take-or-pay settlement costs are expenses related to the acquisition of gas supplies and should therefore be classified as production-related and recovered through the pipeline's commodity rates.
>
> Recovery through commodity rates exposes the pipeline to the risk of undercollecting its settlement costs due to the effect of market forces. While this provides an incentive for the pipeline to minimize its settlement costs and is consistent with the Commission's finding in Order No. 500 that all segments of the industry should share in the costs of resolving the take-or-pay problem for which no single segment was at fault, the Commission recognized in Order No. 500 that another mechanism may be justified for pipelines transporting under Part 284. The Commission stated that these pipelines, which are making the transition from merchants to transporters, may find it more difficult to recover their take-or-pay settlement costs in their sales commodity rates, because they will be making fewer sales as they transport more gas. Accordingly, the Commission adopted an alternative passthrough mechanism for these pipelines under which they are permitted to recover a portion of their settlement costs through a fixed take-or-pay charge. Under the alternative mechanism, if a pipeline is willing to absorb from 25 to 50 percent of its take-or-pay settlement costs, then it will be allowed to recover, through a fixed charge, an amount equal to the percentage it is willing to absorb. The remainder may be recovered through a volumetric surcharge on all throughput.
>
> Recovery of production-related costs through a fixed charge is an extraordinary mechanism which the Commission has rarely permitted. Because a fixed charge guarantees the pipeline recovery of the costs included in the fixed charge, it is inconsistent with the Commission's general policy that recovery of production-related costs should be subject to market forces. Furthermore, allowing a pipeline to recover 100 percent of its settlement costs through a fixed charge would be inconsistent with the Commission's holding

> in Order No. 500 that all segments of the natural gas industry should share in the burden of resolving the take-or-pay problem, since no single segment of the industry was to blame for its take-or-pay problems. Accordingly, the Commission believes it appropriate to require pipelines that wish to avail themselves of the alternative, fixed charge mechanism to absorb a portion of the costs as described above. The Commission is not required to guarantee a pipeline's recovery of its costs; the Commission need only provide a pipeline a reasonable opportunity to recover its prudently incurred costs. The basic passthrough mechanism, under which pipelines may include in their commodity rates all prudently incurred settlement costs, gives pipelines this opportunity.[50]

Further, Order No. 500 formulated a "purchase deficiency" allocation method under which

> [t]he amounts to be recovered through fixed charges were allocated on the basis of each customer's "purchase deficiency." The purchase deficiency was calculated by measuring the customer's purchases in the "deficiency period," the period during which the pipeline incurred the bulk of the take-or-pay liability in question, against the customer's purchases in a prior "base period." Thus customers were assigned a portion of the pipeline's take-or-pay costs in proportion to the extent their purchases declined during the deficiency period.[51]

Q36. Was that solution ultimately implemented?

A36. No, in *Associated Gas Distributors v. FERC*,[52] the Court of Appeals decided "that the purchase deficiency method of allocating such costs violated the filed rate doctrine because the fixed charges, even though recovery of a current cost, were in fact charges for purchases during the deficiency period."[53] Therefore, on remand, FERC decided that "take-or-pay settlement costs may be collected . . .

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50 Order No. 500-H at pp. 31,574-5 (footnote omitted).

51 *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, 53 FERC ¶61,163 at p. 61,593 (1990) (hereinafter, "Order No. 528").

52 893 F.2d 349 (D.C. Cir. 1989) ("*AGD II*"), *cert. denied sub nom. Berkshire Gas Co. v. Associated Gas Distributors*, 111 S.Ct. 277 (1990).

53 Order No. 528 at p. 61,593 citing *AGD II* at 355.

through [a] methodology that makes use of current or test year contract demand or some other measure of usage of the pipeline system."[54]

However, despite the fact that the Court struck down that particular approach, FERC remained committed to devising an approach that resulted in cost sharing between the pipeline and its customers. In particular, FERC articulated the following principles: (1) "costs must be spread as broadly as possible throughout the industry,"[55] (2) "[t]he pipeline must absorb a significant portion of the costs,"[56] (3) "[m]inimize burdens on the pipelines' captive sales customers, especially small customers,"[57] and (4) "[p]ipelines and producers should abide by existing settlement agreements."[58]

Further, Order No. 528-A[59] "cap[ped] at 50 percent the amount of costs that can be recovered through volumetric surcharges for costs that were previously included in [an Order No. 500 related filing]"[60] and at "75 percent [for] new costs not previously included in an Order No. 500 [related] filing."[61] FERC reasoned that "volumetric surcharges could cause producers to bear even more of the burden of resolving the industry's take-or-pay problems . . . because the purchaser might be unwilling to purchase the gas unless its total costs, including transportation costs, are less than the cost of obtaining alternative fuels or multiple sources of supply."[62] FERC also "require[d] pipelines to reallocate 50 percent of the take-or-pay settlement costs that would otherwise be allocated to

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54 *Id.* at p. 61,595.

55 *Id.* at p. 61,596.

56 *Id.* at p. 61,597.

57 *Id.*

58 *Id.*

59 *Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs*, Order Granting Rehearing in Part and Denying Rehearing in Part, 54 FERC ¶61,095 (1991) (hereinafter, "Order No. 528-A").

60 *Id.* at p. 61,290.

61 *Id.* at p. 61,300.

62 *Id.*

small customers under the pipeline's revised allocation method to the pipeline's other customers paying the fixed charge."[63] FERC reasoned that "a special adjustment in the allocation of the fixed charge for small customers [is needed] to achieve the Commission's objective of minimizing harm to small captive sales customers."[64]

FERC clarified as follows:

> Order No. 528-A reasoned that, *because the take-or-pay problem was caused more by general market conditions* than by any regulatory action of the Commission and *the underlying take-or-pay contracts were no longer used and useful, it was appropriate to require the pipelines to share in the losses arising from those market conditions.*[65]

Therefore, as FERC has clearly and repeatedly stated, where an asset is "no longer used and useful" due to "general market conditions," it is "appropriate to require the pipeline to share in the losses arising from those market conditions."

Q37. What mechanism did FERC develop to effectuate this type of cost sharing?

A37. FERC allowed two mechanisms for pipelines to pass through take-or-pay costs. The first, or traditional method, is recovery of all these costs through *commodity/volumetric* sales rates. Recovery through commodity rates exposed the pipeline to the risk of undercollecting its costs due to the effect of market forces, especially in an oversupply market environment. This provides an incentive for the pipeline to minimize its costs and is consistent with the principle that all segments of the industry should share in these costs.

The second, or equitable sharing, mechanism, is an alternative to the first. It provides that, if a pipeline is willing to absorb from 25 to 50 percent of its take-or-pay costs, then it will be allowed to recover, through a *fixed* charge, an amount

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[63] *Id.*

[64] *Id.*

[65] Order No. 636-C at p. 61,785 citing Order No. 528-A, 54 FERC at pp. 61,303-5 (1991) (emphasis added).

equal to the percentage it is willing to absorb. The remainder may be recovered through a *volumetric* surcharge on all throughput. For example, if a pipeline wants to recover 25 percent of take-or-pay costs through a fixed charge, it must absorb 25 percent of the costs, and be at risk for the remaining 50 percent by collecting them through a volumetric rate. If it wants to recover 50 percent of the costs through a fixed charge it must absorb the other 50 percent.[66]

Q38. Can you further explain FERC's rationale for cost-sharing in this context?

A38. Yes. FERC recognized that "it is difficult to assign blame for the pipeline industry's take-or-pay problems. In brief, no one segment of the natural gas industry or particular circumstance appears wholly responsible for the pipelines' excess inventories of gas. As a result, all segments should shoulder some of the burden of resolving the problem."[67]

Accordingly, in the settlements between the producers and the pipelines related to take-or-pay contracts and payments, FERC found that the producers made "significant concessions [and thereby] shouldered a substantial portion of the burden of resolving the take-or-pay problems."[68]

Q39. Can you give examples of how the costs were actually apportioned between investors and ratepayers in take-or-pay cases?

A39. The cases implementing FERC's apportionment policies relate mostly to the settlements resulting from the application of these policies to specific pipelines.

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66 *See* Order No. 500 at p. 30,787 (footnote omitted):

> pipelines may in their discretion agree to assume anywhere from 25 to 50 percent of their costs; provided, however, that a pipeline may not claim recoupment through a fixed charge of any amount in excess of that which it is willing to absorb. The pipeline may seek to recover the remaining amounts, not to exceed 50 percent of total take-or-pay costs, at its option, through a commodity rate surcharge or a volumetric surcharge on total pipeline throughput.

67 Order No. 500 at pp. 30,778-9.

68 Oder No. 500-H at p. 31,523.

Therefore, the following cases mostly reflect examples of the parameters of these settlements, as approved by FERC.

For example, Natural Gas Pipeline Company of America ("NGPL") "absorbed 50 percent of the costs and began recovering 50 percent of the jurisdictional portion of its transition costs through a fixed charge . . ."[69] Under a settlement agreement, NGPL "accept[ed] the 'equitable sharing' principle of absorbing 50 percent of its transition costs and agree[d] not to pursue recovery of these costs in any other forum."[70]

Also, under a settlement agreement, Panhandle Eastern Pipe Line Company "agree[d] to absorb $200,695,753, or 50 percent of its buy-out and buy-down costs paid to producers."[71]

Further, El Paso Natural Gas Company ("El Paso") proposed, and FERC generally approved, that El Paso would "absorb 25 percent of the costs, direct bill 25 percent, and recover the remaining 50 percent through a volumetric surcharge."[72]

Furthermore, under a settlement agreement, Trunkline Gas Company ("Trunkline") "agree[d] to absorb $197,444,206, or 50 percent of the total take-or-pay costs. . . . Trunkline would recover the remaining $197,444,208 as follows: . . . $164.7 million through a fixed charge[, by] retaining $8,051,116 of . . . refunds to which its customers may become entitled[,] . . . [and] an additional $24,686,339 of take-or-pay buy-out and buy-down costs, plus carrying charges, by means of a volumetric surcharge."[73]

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69 *Natural Gas Pipeline Company of America*, 56 FERC ¶61,142 at p. 61,519 (1991).

70 *Id.* at p. 61,520.

71 *Panhandle Eastern Pipe Line Company*, 56 FERC ¶61,210 at p. 61,841 (1991).

72 *El Paso Natural Gas Company*, 56 FERC ¶61,061 at p. 61,239 (1991).

73 *Trunkline Gas Company*, 56 FERC ¶61,209 at pp. 61,836-7 (1991).

Q40. Has TCPL addressed the take-or-pay issue in the context of this case?

A40. Yes. TCPL has stated as follows:

> In the U.S. gas industry, the most prominent example of stranded cost recovery policy arose with respect to the uneconomic take-or-pay contracts that were a legacy of the pre-liberalization regulatory policy in which pipelines were merchants as well as transporters (in some respects similar to the TransCanada take-or-pay problem described above) . The stranded cost issues associated with out-of-market contracts differ somewhat from those that arise with respect to the stranding of physical assets whose costs were determined to have been prudently incurred. In the case of the contracts there was no presumption that the costs incurred by pipelines to "buy-out" or "buy-down" the price under the contracts were prudently incurred in advance of determining whether such costs should be passed through to customers. Nonetheless, the experience in the U.S. with this issue is instructive:
>
> FERC Order Nos. 436, 500 and 528 - With Order Nos. 436 and 500, the FERC encouraged "voluntary" open-access policies on pipelines. Because of competition between pipelines and the potential for bypass, most pipelines saw the program as involuntary. Their dilemma involved either rejecting the FERC's program and losing transportation volumes (and exposing themselves to antitrust litigation), or embrace the program and risk exposure under their take-or-pay contracts. Most pipelines opted to implement open-access transportation. The FERC's policy initially allowed pipeline customers to adjust their contract demand entitlements without relieving the pipeline companies of their purchase contract obligations. This policy was ultimately struck down by the U.S. Court of Appeals, partly on the grounds that the FERC did not adequately deal with the take-or-pay contract problem. In responding to the Court remand, the primary issue involved who should bear the costs associated with buying-out, or buying-down the price, in these contracts. In Order No. 500, the FERC provided mechanisms for resolving the current liabilities, as well as preventing future take-or-pay liabilities from being incurred. The FERC's approach initially was to attempt to share the burden among pipelines, local distribution companies (LDCs) and end users.
>
> Under traditional ratemaking, pipelines could recover 100% of any contract settlement costs as a surcharge on their commodity sales rate (subject to regulatory review of the "prudence" of their decisions). But such a recovery mechanism was not particularly

> attractive to pipelines because an increase in the volumetric charge on a pipeline risks the loss of throughput as customers cut back on their demand, switch fuels, or bypass the pipeline altogether. In Order No. 500, an alternative mechanism was set up to induce a "sharing" of the cost of take-or-pay contract reform. Under the Order No. 500 sharing mechanism, and after a pipeline elected to become an open-access transporter, if it agreed to absorb 25 to 50 % of its total take-or-pay contract settlement costs, then it would be entitled as a quid pro quo to recover an equal share of these costs by directly levying a fixed charge on its firm sales customers. The remaining amount, not to exceed 50 %, could be collected through a volumetric surcharge on total pipeline throughput. The volumetric portion of this mechanism faced the same risk as did the commodity charge in the traditional ratemaking mechanism. Since the courts and FERC wanted contract settlement payments to be only paid by current customers (and not customers that had "departed"), the "purchase deficiency methodology" of Order No. 500 (through which a customer's share of the fixed levy is based on how much the customer has reduced its purchases in recent years relative to other customers of the same pipeline) was struck down by the courts as "retroactive ratemaking." The revised Order No. 528 laid down principles for recovering the settlement costs, and concurrently provided flexibility for pipeline companies to come up with more equitable recovery mechanisms.[74]

Clearly, TCPL agrees that the treatment of take-or-pay contracts and the related equitable sharing of the burden between investors and shareholders is a relevant consideration for this case.

Q41. Do you agree with TCPL's explanation of the take-or-pay issue?

A41. In part, yes. However, TCPL's explanation seems to imply that FERC's policy in the take-or-pay cases was intended for the advantage of the pipelines. In fact, FERC's pronouncements show the exact opposite. As mentioned above, FERC's reasoning was clearly stated as follows: "because the take-or-pay problem was caused more by general market conditions than by any regulatory action of the Commission and the underlying take-or-pay contracts were no longer used and useful, *it was appropriate to require the pipelines to share in the losses* arising

[74] *See* TransCanada's Responses to Round 3 Information Requests, Pages 5-6 of Response to NEB 3.1.

from those market conditions."[75] Therefore, FERC's intention from the take-or-pay cases was to *require pipelines to share in the losses*. This imposes a burden on pipelines and does not relieve them from a burden as TCPL implies.

C. FERC's Response to Unsubscribed or Turned Back Capacity

Q42. Are there other precedents related to the sharing of costs associated with turned back or unsubscribed capacity that might be of interest?

A42. Yes. In cases where pipeline customers turn back capacity, FERC does not allow the pipeline to place the full burden of the costs related to this unutilized or excess capacity on the remaining customers. Instead, FERC requires that the pipeline and the customers share these costs. FERC has also expressed a clear preference for sharing mechanisms where the customers' burden is limited to a specific period of time after which the pipeline becomes 100% responsible for the costs and during which the pipeline bears most of the cost.

Q43. Did FERC find that the pipelines' actions were imprudent as a prerequisite of determining that the costs related to turned back capacity had to be shared between the pipeline and its customers?

A43. No. The cost-sharing in capacity turn-back cases is independent of a prudency review. Specifically, in *El Paso Natural Gas Co.*,[76] FERC stated: "Notwithstanding the absence of a finding of imprudence on the part of El Paso, there are other considerations with respect to a pipeline's responsibility when faced with turnback capacity which have been addressed by this Commission."[77]

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[75] Order No. 636-C at p. 61,785 citing Order No. 528-A, 54 FERC at pp. 61,303-5 (1991) (emphasis added).

[76] 84 FERC ¶ 63,004 (1998) ("*El Paso II*").

[77] *Id.* at p. 65,006.

Q44. Can you give examples of cost-sharing in the context of turned back capacity?

A44. Yes. In *Transwestern Pipeline Company*,[78] FERC approved a settlement where "Current Customers share the costs attributable to [Southern California Gas Company's ("SoCal")] capacity relinquishment over a five-year period, through a demand charge."[79] FERC described the sharing mechanism as follows:

> The Current Customers have two options for sharing the demand surcharge costs. Under Option No. 1, the Current Customers split costs with [Transwestern Pipeline Company ("Transwestern")] (50/50) for the first year of the surcharge, and the Current Customers' percentage decreases and Transwestern's increases (25/75) for years two through five. In year six Transwestern absorbs 100 percent of the costs. Under Option No. 2, Current Customers, other than SoCal, pay a fixed (30.67) percentage for the entire five year period.[80]

FERC added:

> The centerpiece of the settlement is the cost-sharing mechanism for approximately $51 million in costs related to SoCal's . . relinquishment of 457 MMBtu/day of capacity on Transwestern's system. The Shared Cost Surcharge proposed in the settlement is an inventive risk-sharing mechanism whereby Transwestern and its current firm customers share the relinquishment costs until the year 2001, at which time Transwestern assumes responsibility for 100 percent of the costs related to the returned capacity. This mechanism is crafted so as to fairly share the costs and burdens associated with the relinquished capacity.[81]

In *El Paso Natural Gas Co.*,[82] FERC approved a settlement similar to the one in the *Transwestern* case. FERC stated:

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78 72 FERC ¶61,085 (1995) ("*Transwestern*").

79 *Id.* at p. 61,446.

80 *Id.* at p. 61,446 (special arrangements were made for SoCal, the customer relinquishing the capacity).

81 *Id.* at p. 61,447-61,448.

82 79 FERC ¶61,028 (1997) (*El Paso III*).

> we find the Settlement to be fair and reasonable, and in the public interest, and accept the Settlement as to the consenting parties. Our action is consistent with the decision in [*Transwestern*] where the Commission approved a settlement which included a risk-sharing mechanism for costs associated with the turnback capacity on Transwestern's pipeline system. There, as in the El Paso settlement, the pipeline and its customers shared the costs for an initial period, and thereafter the pipeline assumed all the costs. In approving the Transwestern settlement, the Commission stated that the risk sharing mechanism was the centerpiece of the settlement and "is crafted so as to fairly share the costs and burdens associated with the relinquished capacity."[83]

Additionally, in *Mississippi River Transmission Corp.*,[84] FERC rejected a cost-sharing proposal partly because the pipeline proposed to absorb only 50% of the cost and left the sharing open-ended without proposing a time limit on the customers' burden. FERC stated:

> The [prior order] rejected [Mississippi River Transmission's ("MRT")] proposal. . . . [T]he Commission stated that the circumstances in this case are not analogous to those in *El Paso III* and *Transwestern* . . . The Commission explained that those cases involved settlements where the quantity and timing of the turnbacks were known. Further, the Commission explained that in those cases, *the pipeline agreed to absorb a larger share of the costs* than MRT proposes to absorb, *and the mechanism terminated after a specified period.*[85]

FERC added:

> Every pipeline faces a risk of capacity turnback or unsubscribed capacity when its contracts expire. The Commission has stated that, if such turnback occurs, pipelines have an obligation to attempt to develop new business opportunities to make use of the capacity. . . . The Commission has not held that pipelines must necessarily bear the *full* costs of capacity turnback, but the Commission is mindful of its *obligation to protect captive customers and is concerned that captive customers not be required to bear a burdensome portion of costs associated with capacity*

83 *Id.* at p. 61,127 (citing *Transwestern* at p. 61,448).

84 95 FERC ¶ 61,460 (2001).

85 *Id.* at p. 62,658 (emphasis added).

> *turnback. The Commission does not guarantee pipelines recovery of costs associated with capacity turnback.* [citing *United Distribution Companies v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *cert.denied*, 117 S. Ct. 1723 (1997)] As the Commission pointed out in the prior order, the Commission has, on a case-by-case basis, approved cost-sharing and revenue sharing in settlements where the quantity and timing of the turnbacks were known, the pipeline agreed to absorb a larger potion of the costs than MRT proposes to absorb, and the cost-sharing mechanism terminated after a specified period.
>
> In this case, MRT has not experienced any capacity turnback, but it has proposed an open-ended tariff mechanism that would allow it to charge its remaining customers 50 percent of the costs of any capacity turnback that may occur in the future. The Commission does not find such a general tariff provision to be just and reasonable. The mechanism would operate regardless of whether MRT had attempted to remarket the capacity and it would have no termination date . . .
>
> The Commission will not approve an open-ended general tariff provision that permits the pipeline to recover half the costs of all capacity turnback from their remaining customers for an indefinite period of time.[86]

Further, in *El Paso Natural Gas Company*,[87] FERC stated:

> The Commission recognizes that some cost-sharing may be appropriate when a large, historic customer leaves a system that was originally designed to meet its needs. When historic customers terminate service at the end of their contracts *it is not appropriate to expect the remaining customers . . . to pay for all the remaining costs of the pipeline*. The pipeline has some obligation to attempt to develop new business opportunities to make use of its unused capacity.[88]

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86 *Id.* at p. 62,659 (emphasis added, footnotes omitted).

87 72 FERC ¶61,083 (1995) ("*El Paso I*").

88 *Id.* at p. 61,441 (emphasis added).

Furthermore, in *Natural Gas Pipeline Co.*,[89] FERC did not allow the pipeline to charge its remaining customers for the costs of unsubscribed capacity. FERC stated:

> the Commission advises Natural that we will not permit the . . . rates, which reflect customer service elections and the related pathing changes, to be implemented. Those rates have the effect of reallocating to Natural's remaining customers the costs of the capacity which will become unsubscribed as a result of the expiration of the firm customers' current contracts and the negotiation of contracts for the new services. That would lead to a 50 to 60 percent increase in the maximum rates paid by the captive customers who do not receive discounts. . . .. It would not be fair to require Natural's captive customers to pay rates that are 50-60 percent higher for the same services, with the same cost of service.[90]

FERC re-emphasized its policy regarding cost-sharing of turned-back capacity and stated:

> As the Commission stated recently in [*El Paso I*], *a pipeline cannot expect to be able to recover all the costs of its unsubscribed capacity from its remaining customers*. It is appropriate for a pipeline's customers to pay their fair share of the pipeline's costs in proportion to the capacity they use. But *the Commission will not permit a pipeline losing customers simply to shift the costs of resulting unsubscribed capacity to the remaining customers without regard to the adverse effects on those customers*. Rather, the pipeline must have an incentive to recover the costs of its unsubscribed capacity from new markets. *This principle is an important safeguard for the pipeline's existing customers, particularly captive customers, against pipeline overreaching*.[91]

Furthermore, in *El Paso II*, FERC required that "turnback costs . . . be shared equally by both El Paso and its customers."[92] FERC clarified its turnback cost-sharing policy by quoting from *NGPL II*, *El Paso I*, and *Transwestern* (as quoted

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[89] 73 FERC ¶ 61,050 (1995) ("*NGPL II*").

[90] *Id.* at p. 61,129.

[91] *Id.* (emphasis added, footnote omitted).

[92] *El Paso II* at p. 65,007.

above) and concluded as follows: "Therefore, consistent with Commission policy, El Paso's customers should not bear all of the costs associated with the turnback."[93]

Thus, including unsubscribed capacity costs in TCPL's maximum rates significantly reduces the financial risk to TCPL and reduces the incentive TCPL has to market that unsubscribed capacity. This would inappropriately shift the risk of overbuilding capacity from the pipeline to the shippers, while the potential benefit of return on capital investment continues to be captured by the pipeline. Additionally, unsubscribed capacity is, by definition, capacity that a pipeline does not use to meet the needs of any shippers and therefore, allocating its costs to shippers is contrary to FERC's repeated stated goal of safeguarding customers "against pipeline overreaching."

D. FERC's Response to Failed Gas Supply Projects and the "Used and Useful" Analysis

Q45. You mentioned earlier that costs related to abandoned assets must be excluded from rate base, are there other situations in which FERC has disallowed full cost recovery related to prudently incurred expenses?

A45. Yes, as I briefly mentioned earlier, there is a line of cases involving the appropriate ratemaking treatment of costs related to failed gas supply projects.

Q46. Please explain.

A46. One such case in *NGPL I* mentioned above.[94] In this case, NGPL sought to recover costs associated with three gas supply projects. Each of these gas supply projects was unsuccessful and NGPL eventually sought to recover certain costs related to each. NGPL did not seek to include the expenses in its *rate base* (and therefore was not proposing to earn a return on an investment in a failed project).

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93 *Id.*

94 *Natural Gas Pipeline Company of America v. FERC*, 765 F.2d 1155 (D.C. Cir. 1985) ("*NGPL I*")

Rather, NGPL argued that it should be allowed to recover through its *cost of service* its prudently incurred expenses for these failed projects.

Q47. How did FERC view these arguments?

A47. FERC rejected NGPL's proposal and held that "[t]he used and useful principle does not permit the pipeline to shift the risk of loss by imposing the expenses of the unsuccessful project upon its current ratepayers who have received no benefit from the project."[95] NGPL appealed this decision to the U.S. Court of Appeals for the D.C. Circuit.

On appeal, FERC argued that the expenses were not used and useful to ratepayers and therefore should not be included in the cost of service, but instead should be a "risk to be shouldered by the shareholders."[96]

Q48. How did the Court view these arguments?

A48. The court stated that,

> [a]t bottom, Natural's claim is that *because it acted prudently*, it cannot fairly be punished by nonrecovery of its expenses. But the problem of risk allocation in this case is not a problem of fault. *The Commission did not find that the disputed expenditures were imprudent, and we therefore assume that the natural gas pipeline and its ratepayers were equally blameless for the losses at issue.* That assumption, however need not lead to the conclusion that Natural's ratepayers must, through the utility's cost of service, make good on all or any party of the money Natural lost. The Natural Gas Act simply *does not guarantee the shareholders of even a prudently managed utility that ratepayers can always be stuck with the bill for supply projects that turn out to be total failures, however praiseworthy the utility's motives for undertaking these projects may have been.*[97]

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95 *NGPL I*, 765 F.2d at 1161 citing *Columbia Gas Transmission Corporation*, Opinion No. 101, 13 FERC ¶61,102 at p. 61,222 (1980).

96 *NGPL I*, 765 F.2d at 1158.

97 *Id.* at 1163-64 (emphasis added).

Q49. How did the court decide the case?

A49. The Court held in favor of FERC's view, and thus denied NGPL's attempt to seek cost recovery for failed supply projects.

Q50. Are there other cases in which the FERC refused to allow interstate pipelines to recover costs associated with failed supply projects?

A50. Yes, as the Court noted in *NGPL I*, FERC has an "established policy of disallowing costs of unsuccessful alternate gas supply projects to be included in jurisdictional rates."[98]

Further, FERC has disallowed costs expended in unsuccessful projects related to the production of synthetic natural gas ("SNG") because it found that the expenditures were not "used and useful" in providing service and should not be charged to the rate payers since the projects did not produce any jurisdictional gas.[99]

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98 *Id.* at 1159.

99 *See, e.g., Tennessee Gas* Pipeline *Co. v. Federal Energy Regulatory Com.*, 606 F.2d 1094, 1123-1124 (D.C. Cir. 1979). Further, in *Northern Natural Gas Co.*, 4 FERC ¶ 61,312 at p. 61,706 (1978), FERC explained its policy and precedent regarding disallowing the costs of unsuccessful alternate gas supply projects as follows:

> In Opinion No. 801 [*Transcontinental Gas Pipe Line Corp.*, Opinion No. 801, issued May 31, 1977, in Docket Nos. RP74-48 and RP75-3, 58 FPC 2038 at 2043], the Commission considered Transco's application to amortize, as an operation and maintenance expense, some $12 million expended for four non-R&D SNG projects which Transco ultimately abandoned for a variety of reasons [*id.*]. The Commission concluded: "Although we support further SNG development, the jurisdictional ratepayer should not bear the full risk [*id.*]" On rehearing, the Commission added:
>
> . . . even if these SNG project expenditures are assumed to be prudent, rate base inclusion . . . is not necessarily mandated. Part and parcel of the "prudent investment" theory is the "used and useful" requirement; that is, only prudent investment for utility property which is used and useful to provide service to the utility's customers should be compensated [Opinion No. 801-A, issued July 29, 1977, 59 FPC 1237 # at 1239].
>
> Similarly, Texas Eastern Transmission Corporation submitted a settlement, article VI of which provided for the amortization of five nonjurisdictional, non-R&D projects which had been designed to develop new or supplemental gas supplies but which had been terminated. Again, the prudence of the investments

(continued...)

E. FERC's Response to Other Failed Projects

Q51. Are there any other cases involving the concept of "failed" projects?

A51. Yes. The concept of "failed project" was also used in *Koch Gateway Pipe Line Company*.[100] In that case, Koch Gateway Pipe Line Company ("Koch Gateway") requested to include the costs of the SunCoast Pipeline ("SunCoast") which was never built and no certificate application for the project was ever filed with FERC.[101] Koch Gateway argued that the basis for the project was the rapidly expanding natural gas markets in Florida, that the SunCoast project was one of several projects considered for meeting increased Florida demand, that Koch Gateway continues to benefit from the analysis of the pipeline's ability to source gas from various locations and the required investment and returns associated with each, and that initial expectations for the SunCoast expenditures were confirmed by Florida's market needs.[102]

(...continued)

was not challenged. In its order modifying and accepting the settlement, the Commission deleted article VI, stating:

> We have recently reaffirmed our established policy of disallowing the costs of unsuccessful alternate gas supply projects to be included in jurisdictional rates [citing Opinion Nos. 801, 58 FPC 2038, and 738, 53 FPC 1287]. In those cases we have held that, while we endorse such efforts as potentially beneficial to the interstate market, we view the risks associated with such efforts as properly borne by the shareholders and not the jurisdictional ratepayer [*Texas Eastern Transmission Corp.*, order issued June 6, 1977, in Docket No. RP75-73 , 58 FPC 2412 at 2423].

See also *Transcontinental Gas Pipe Line Corp. v. F.E.R.C.,* (1979) Cir. 606 F. 2d 1094; in affirming Opinion Nos. 801 and 801-A mentioned above, the court stated:

> These expenditures were prudent investments, argues Transco; however, for rate base inclusion expenditures must satisfy not only the necessary condition of prudent investment but also must be "used and useful" in providing service. The Commission did not abuse its discretion when it applied a policy "that SNG expenditures which do not qualify as R & D can be recovered, if at all, only through the price paid for actual SNG production sold in interstate commerce."

Id. at 1123-1124.

[100] 68 FERC ¶ 61,189 (1994).

[101] *Koch Gateway Pipe Line Company*, 68 FERC ¶ 61,189 at p. 61,954 (1994).

[102] *Id.* at pp. 61,954-61,955.

Again citing *NGPL I*, FERC rejected Koch Gateway's request, reasoning as follows:

> we conclude that Koch Gateway's ratepayers should not bear the cost responsibility for the SunCoast project. Koch Gateway's justification for inclusion of these expenses is that they continue to benefit Koch Gateway's ongoing system analysis and marketing efforts today, and that all Koch Gateway's customers will benefit as a result if SunCoast or some other pipeline project is ultimately built. Further, it is alleged that consumers will benefit from legislation designed to encourage competition in the natural gas industry. These allegations are extremely speculative and any connection between the alleged benefits and the SunCoast project is extremely tenuous.[103]

Q52. Are you aware of any case where FERC declined to apply the "failed project" concept?

A52. Yes. FERC declined to apply the "failed project" concept in the case of the Great Plains gasification project.[104] In that case, four natural gas pipeline companies (including Transcontinental Gas Pipeline Corporation ("Transcontinental")) formed a partnership named Great Plains Gasification Associates ("Great Plains") to build and operate a coal gasification plant in North Dakota designed to use lignite coal to produce synthetic natural gas. However, faced with the economic realities of the mid 1980's, Great Plains defaulted on its financial obligations, was foreclosed upon, and a Trustee was appointed to operate the plant. Nonetheless, FERC allowed Transcontinental to recover its costs in the project.

Q53. It appears that FERC viewed the facts of this case differently than cost recovery in other cases. Why is that?

A53. According to FERC, this case was different, because of the project's significant technological benefits. FERC stated:

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[103] *Id.* at pp. 61,955-61,956.

[104] *Transcontinental Gas Pipe Line Corporation*, 55 FERC ¶ 61,446 (1991).

> The Great Plains project was a *pioneering and unique* project which, at the time of Commission approval, was thought to provide national benefits to a primarily bundled sales pipeline system. . . . Hence, the Commission concludes that it is reasonable for all of Transco's customers to share in the above-market costs of the nation's first large-scale synthetic fuels plant, whose technological benefits would have redounded to all future gas users (including CNG) by increasing the supply of available gas.[105]

Therefore, FERC's allowance of recovery in the Great Plains case is explained by FERC's consideration of the Great Plains project as being a "pioneering and unique" project with "national benefits." Such considerations do not appear to be present in TCPL's case.

F. <u>FERC's Response to Assets that May Be Returned to Service in the Future</u>

Q54. Has FERC addressed any situation where assets are no longer "used and useful" but may be returned to service in the future?

A54. Yes, in *Panhandle Eastern Pipe Line Company,*[106] a FERC Administrative Law Judge ("ALJ") addressed the issue of facilities that are no longer "used and useful," but may be returned to service in the future. The ALJ stated that:

> where certificated facilities are determined to no longer be "used and useful", but may be returned to service in the future, such plant would be removed from Gas Plant in Service (Account No. 101) and moved to Gas Plant Held For Future Use (Account No. 105). . . . If there is not a potential for returning the certificated facility to service, [FERC] authority for abandonment would have to be obtained and the facility would be retired in accordance with the Gas Plant Instruction No. 10 of Commission Regulations.[107]

However, in reviewing the ALJ's decision, FERC considered intervenors' argument that certain compressors were not "used and useful" and that the

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105 *Id.* at p. 62,341.

106 68 FERC ¶ 63,008 (1994).

107 *Panhandle Eastern Pipe Line Company*, 68 FERC ¶ 63,008 at pp. 65,079-65,080 (1994).

pipeline was no longer entitled to recover the cost of such property.[108] FERC decided that it could not "find that the compressors were not "used and useful" during the period at issue in that proceeding."[109] Nonetheless FERC noted that intervenors are

> free in subsequent Panhandle rate cases to address the issue of whether these compressors were used and useful in the periods at issue in those cases. If these compressors have not been put back in service in succeeding rate periods, the Commission may require Panhandle to file abandonment certificates for them, and, ultimately, to remove them from rate base.[110]

Therefore, under *Panhandle*, if an asset is shown to be no longer "used and useful", FERC may require that it be abandoned and removed from rate base.

Q55. Does FERC allow ratepayers to be at risk for facilities that become no longer "used and useful"?

A55. No. In *Boundary Gas, Inc.*,[111] FERC refused to allow a contract provision putting ratepayers at risk if facilities become no longer "used and useful." FERC stated:

> We note that Tennessee's *pro forma* transportation agreement . . . provides that in the event [FERC] were to declare these facilities no longer used and useful, Tennessee would bill each shipper for its proportional share of Tennessee's unrecovered incremental facility costs. For the reasons expressed above, *we believe it premature at this time to approve a contract provision that would allow Tennessee to pass the ultimate cost responsibility for these facilities to the individual shippers. Such time, if any, that we declare these facilities no longer used and useful would be the appropriate moment to determine the proper treatment of any unrecovered facility costs.*[112]

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108 *Panhandle Eastern Pipe Line Company*, 71 FERC ¶ 61,228 at p. 61,824 (1995).

109 *Id.* at p. 61,825.

110 *Id.*

111 40 FERC ¶ 61,088 (1987).

112 *Id.* at p. 61,250 (emphasis added).

Therefore, FERC is unwilling to establish a rule that recovery will be allowed for facilities no longer "used and useful" and has adopted a more flexible approach requiring that the issue be decided on a case by case basis if and when changed conditions render an asset no longer "used and useful."

Additionally, FERC has addressed the situation where only part of an asset is "used and useful."

Q56. How did FERC address the situation where only part of an asset is "used and useful"?

A56. FERC has addressed this situation in conjunction with the question whether the pipeline is allowed to include the whole asset in the rate base. In *El Paso Natural Gas Company*,[113] FERC refused to allow El Paso Natural Gas Company ("EPNG") to roll-in 303 miles of pipe where only 87.8 miles were certificated and put in service. EPNG argued that where a utility has

> to purchase a three-acre lot on which to put a compressor that only requires two acres of land because the seller wants to sell the whole lot[, a]rguably the one acre that the compressor is not sitting on is not used and useful[. Nonetheless] . . . the Commission has routinely allowed a pipeline to include the purchase price of the entire lot in rates because the market value of the useful two acres is equal to the purchase price, and assuming there is no willing buyer (*i.e.*, no market) for the remaining acre, the market value of that one acre is zero. EPNG did not want to, but was required to purchase the entire line because of All-American's position on selling the entire line.[114]

FERC disagreed with EPNG stating that:

> EPNG's proposal to roll-in and recover in its cost-of-service $36.2 million it claims was the price of the entire All-American pipeline is unjust and unreasonable. . . . The fact is that by rolling in and seeking to recover the remaining $25.7 All-American purchase

[113] 134 FERC ¶ 63,002 (2011).

[114] *Id.* at P 35.

> price in its cost-of-service rate base, EPNG is seeking to recover costs for facilities that are not "used or useful."[115]

This indicates that where only part of an asset is "used and useful", only that part should be allowed in the rate base.

Additionally, in *United Gas Pipe Line Company*,[116] FERC addressed the factors that it would consider in deciding whether "facilities should be deemed no longer used and useful, and therefore removed *partially* or entirely from rate base."[117] In this context, FERC considers "past, current, and projected use of . . . system capacity, . . . whether there currently are queues for interruptible and firm services using this capacity; the anticipated demand for use of this capacity on a firm basis if it becomes available; the amount of revenues . . . from interruptible transportation services using this capacity; and the length of the periods . . . that interruptible customers have been able to use this capacity without interruption, . . . [and] how this capacity may benefit other customers using the systems through enhanced operational flexibility."[118]

VI. STATE CASE LAW

A. <u>Abandoned or Cancelled Projects</u>

Q57. Have you looked at any legal precedents arising in the various states involving the "used and useful" principle?

A57. Yes. In some states this issue has arisen in the context of the appropriate rate treatment afforded utilities for abandoned or cancelled projects. In general, certain U.S. state cases hold that, when a utility abandons or cancels a project, it may not recover some or all abandonment or cancellation costs. These cases are relevant because they indicate that, if an investment does not result in a "used and

115 *Id.* at P 49.

116 49 FERC 61,278 (1989).

117 *Id.* at p. 62,059 (1989) (emphasis added).

118 *Id.*

useful" facility, costs associated with it may not be recovered from ratepayers.[119] Accordingly, some decisions do not allow *any* recovery of the investment in canceled plants.

For example, in *Office of Consumers' Counsel v. Public Utilities Commission*,[120] the Ohio Supreme Court held that the Ohio commission does not have the statutory authority to treat *any* part of a utility's investment in terminated nuclear generating facilities as amortizable costs to be recovered from ratepayers despite a favorable prudency review. The court stated:

> The commission order engrafts upon the statutory ratemaking scheme an exception that would allow utility companies to recover their investment in unfinished projects ineligible for rate base treatment *if the original decision to build the facilities and the subsequent decision to cancel the projects are prudent* under the circumstances. In so doing the commission has exceeded its statutory mandate. We hold that the commission unreasonably and unlawfully exceeded its statutory authority when it approved amortization of CEI's investment in the four terminated nuclear power plants.[121]

The court added:

> If a utility completes a project that should have been abandoned, then the commission must under the "used and useful" requirement of R.C. 4909.15(A)(1) disallow rate base treatment and under R.C. 4909.154 disallow any claimed operating expenses related to the unnecessary project.[122]

Similarly, no recovery was allowed in *Pacific Power & Light Co.*,[123] where investment in two terminated electric generating facilities were not used to provide service to ratepayers and therefore, the commission had no jurisdiction to

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119 Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Cancelled Plants and Excess Capacity*, 132 U. PA. L. REV. 497 at 518 (1984) (*hereinafter* "Pierce").

120 67 Ohio St. 2d 153 (1981).

121 *Id.* at 166 (emphasis added).

122 *Id.* at 168.

123 53 Pub. Util, Rep. 4th (PUR) 24 (Mont. Pub. Serv. Comm'n 1983).

require ratepayers to compensate the utility for its investment. The Montana commission stated:

> *The commission finds it unnecessary in this proceeding to make any findings with regard to the prudency* of PP&L's participation in these projects. This is so because the standard set forth by the legislature and applied by the commission is whether the projects are used and useful and not whether PP&L was prudent in participating in them. Had the legislature intended to allow utilities to recover from ratepayers all of their 'prudent' investments rather than only those investments that are 'actually used and useful' it could easily have substituted 'prudency' language for the 'used and useful' language in 69-3-109, MCA.[124]

Also, in *Pacific Power & Light Co.*,[125] the Oregon commission decided that the utility may use gains, such as those generated through tax benefits and debt-equity exchange, to offset a portion of the investment in a terminated project; however, investment amounts not covered by such gains must be absorbed by stockholders because the utility may not recover from ratepayers any cost pertaining to facilities not used for providing service to customers.

Q58. Has the cost-sharing principle been applied in this context?

A58. Yes. In most states, when a utility abandons or cancels a project, the abandonment cost is divided between investors and ratepayers by allowing the utility to recover only a part of its out-of-pocket costs. For example, in *Re Atlantic City Electric Company*,[126] the New Jersey Board of Public Utilities' method for sharing abandoned plant losses between ratepayers and investors includes a straight-line amortization period of fifteen years and a denial of rate

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124 *Id.* at 28, P. 21.

125 49 Pub. Util. Rep. 4th (PUR) 82 (Or. P.U.C. 1982).

126 51 P.U.R.4th 109 (N.J. Bd. Pub. Util. 1983).

base treatment for the unamortized balance.[127] This decision effectively allocated eighty-four percent of the costs to the utility and sixteen percent to consumers.[128]

However, a typical abandonment/cancellation case can be found in *Bangor Hydroelectric Co.*[129] In that case, the utility was permitted to amortize its investment over a five-year period, but it was not permitted to include the unamortized balance in its rate base and it was not permitted to recover its allowance for funds used during construction ("AFUDC").[130] This decision effectively allocated the costs of the investment in the canceled plant fifty-one percent to the utility and forty-nine percent to consumers.[131]

B. <u>State Reliance on Securitization as an Option to Reduce Ratepayer Burden</u>

Q59. Are you aware of any additional mechanism that has been used to alleviate the burden of under-utilized assets?

A59. Yes. The burden can be further alleviated if the assets are refinanced and securitized.

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[127] *Id.* at 115 ("[w]ith respect to the request for carrying charges on the unamortized balance, the board has established a policy that effects a sharing of abandonment losses between a utility's investors and its customers by denying rate base treatment of the unamortized balance").

[128] Pierce at 518-519. *See also*, Cleaves, *Article And Comment: Constitutional Protection For The Utility Investor: The Confiscation Doctrine After Cleveland Electric Illuminating Co. v. Public Utilities Commission Of Ohio*, 12 B.C. Envtl. Aff. L. Rev. 527 (1985), which notes with approval the "widely recognized regulatory concept" that "the operation of a public utility involves risks and controls that must be shared equally by investors and consumers." *Id.* at 541. Cleaves adds that, therefore, "a majority of state jurisdictions, along with [FERC], grant only partial recovery" of plant cancellation costs through apportionment methods that distribute losses between investors and consumers. *Id.* at 541.

[129] 46 Pub. Util. Rep. 4th (PUR) 503 (Me. P.U.C. 1982).

[130] *Id.* at 539 ("unlike firms in a competitive industry, utilities rarely face the risk of a complete loss if their expansion decisions turn out to be wrong, *as long as the original decision to invest was prudent.* Thus inclusion of CWIP in rate base removes an important constraint on unnecessary expansion") (emphasis added); *see also id.* at 529.

[131] Pierce at 518-519. FERC generally agrees with the apportionment of costs of cancelled facilities among ratepayers and investors. *See, e.g., Northern States Power Co.*, 17 FERC ¶61,196 at 61,383 (1981) ("We think it entirely appropriate to allocate the carrying costs accruing prior to abandonment to the ratepayers and those pertaining to the amortization period to the utility").

Q60. What is securitization?

A60. TransCanada has explained securitization as a relevant form of cost recovery as follows:

> Securitization is a legal and financial structure that has often been utilized in the energy utility sector. While originally applied as a tool to reduce and recover uneconomic or "stranded" electric utility generation costs, securitization has been extended to other applications, including financing of pollution control equipment and recovery of hurricane damage restoration costs.[132]

TransCanada added:

> Specifically, securitization is a debt financing structure that relies on the use of government-sponsored debt as a substitute for the mix of traditional debt and equity typically used to finance utility capital expenditures. The fundamental purpose of securitization is to achieve a lower cost of capital through the use of very highly-rated debt for 100% of the financing requirements of a utility project. The high debt rating (and lower cost of debt) is achieved through the use of a set of "credit enhancements" that are initiated by governmental action.[133]

Essentially, securitization is

> a financing tool which has been employed for many years to expand the availability and reduce the cost of consumer and business credit. Securitization achieves this purpose by obtaining funds from the securities markets by means of specially developed securities whose attributes are carefully shaped to minimize investment risk and thereby to obtain a high investment rating with corresponding reduced interest cost.[134]

Q61. Has securitization been implemented in the US?

A61. In the context of electric market restructuring, a number of states in the U.S. "have enacted legislation which permits securitization of electric utility stranded

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132 TransCanada's Responses to Round 3 Information Requests, Response to NEB 3.1 at Pages 7-8.

133 *Id.* at Page 8.

134 Walter R. Hall II, *Securitization and Stranded Cost Recovery*, 25 Energy L. J. 173 (2004), *originally published as* 18 Energy L. J. 363 (1997) (*hereinafter* "Hall").

costs."[135] Typically, such a legislation defines "'stranded' or 'transition' costs permitted to be recovered through the securitization process [as those costs] which traditionally would be recoverable under a regulated environment but which may not be recoverable in a competitive electric generation market."[136] As a mechanism mainly designed to support major transitions, proceeds of securitization bonds are normally "used to reduce capitalization, to finance transition costs or acquire transition property." These bonds (often referred to as "transition bonds") "may be issued only after the state public utility commission issues a . . . [financing order] approving the stranded costs to be securitized and the charge to be employed in amortizing and recovering the costs associated with the bonds."[137] This "financing order creates a property right . . . employed as the asset or collateral which supports the credit evaluation of the transition bonds."[138] The legislation typically also includes provisions aimed at "procuring a high credit rating for the bonds."[139]

However, securitization has also been criticized in the sense that, "while providing ratepayers with only 'minuscule' rate reductions, securitization

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135 Hall at 191. These states are California, Pennsylvania, Montana and Rhode Island. A number of other states (*i.e.* Connecticut, Illinois, Massachusetts, Michigan, Nevada, New Hampshire, New Jersey, New York, Texas and Vermont) have considered or enacted similar legislation. *See id* at 191 and notes 43, 44. The most recent state that I am aware of to enact securitization legislation is Ohio. *See* Electric Utility Securitization (House Bill 364, Senate Bill 248), 2011 Ohio Laws File 61 (passed Dec. 14, 2011, effective Mar. 22, 2012). Ohio's legislation enables the Public Utilities Commission of Ohio to "securitize" certain utility assets and achieve lower interest rates in order to save money for ratepayers.

136 Hall at 191 and n. 45 *quoting* 66 PA. CONS. STAT. ANN. § 2803 (West Supp. 1997).

137 Hall at 192 and 47 *citing* 66 PA. CONS. STAT. ANN. § 2812 (West Supp. 1997).

138 Hall at 192 and n. 48 *citing* S.B. 390, 55th Leg., Reg. Sess. § 3, Item 24 (Mont. 1997).

139 Hall at 193. A number of securitization proposals have been brought before state public utility commissions. *See, e.g.*, Hall at 202-204 and notes 3 and 65 *citing* Application of Pacific Gas & Electric Co./Southern California Edison Co./San Diego Gas & Electric Co. For Authority to Reduce Rates Effective January 1998 *etc.*, Application Dockets A9705006, A9705018 & A9705022, Interim Order-Decision No. 97-09-054, Financing Orders-Decision Nos. 97-09-055, 97-09-056 & 97-09-057 (Ca. P.U.C., September 3, 1997) (California utilities authorized to issue $7.4 billion of rate reduction bonds to securitize a portion of their claimed stranded costs in excess of $28 billion; this securitization is expected to produce a 10% rate reduction over 4 years); Application of PECO Energy Company for Issuance of a Qualified Rate Order under Sections 2808 and 2812 of the Public Utility Code, 177 Pub. Util. Rep. 4th 417, Docket No. R-00973877 *et al* (Pa. P.U.C., May 22, 1997); Joint Petition for Partial Settlement of PECO Energy Company's Proposed Restructuring Plan and Application for a Qualified Rate Order, Docket No. R-00973953 (Pa. P.U.C., August 26, 1997).

provides utilities with legislatively guaranteed recovery of their stranded costs, which costs are by definition uneconomic and of little or no value to ratepayers."[140]

As TCPL agrees, securitization is mainly designed to recover "electric utility stranded costs."[141] Normally, securitization is used to recover the costs of facilities that are stranded because of major changes in regulatory policy. Securitization in the U.S. is typically related to electric market restructuring. It is typically "proposed as a part of broad legislation which comprehensively restructures the electric industry and state utility regulatory processes to permit a competitive electric market place."[142]

C. <u>Excess Capacity: Reducing the Return on Equity Invested in Non-"Used and Useful" Assets</u>

Q62. Can the return on equity be affected by whether an asset is "used and useful?"

A62. Yes. In Colton, *Excess Capacity: Who Gets the Charge From the Power Plant?*[143] the author asserts that "consumers should not pay the entire cost of excess capacity; rather, utility companies and investors should bear all or part of the burden."[144]

Colton argues that one reason for high utility rates is over-construction[145] and advocates that "shared-risk" and "used-and-useful" theories be used to address over-construction.[146] "Placing the risk of not receiving a full return on equity

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140 Hall at 174.

141 Hall at 191; *see also* TransCanada's Responses to Round 3 Information Requests, Response to NEB 3.1 at Pages 7-8.

142 Hall at 191.

143 34 HASTINGS L.J. 1133 (1983) (*hereinafter* "Colton").

144 Colton at 1136.

145 *Id.* at 1133.

146 *Id.* at 1150.

upon common stockholders is in part justified by the compensation that those investors receive to take such risks."[147] If customers pay for "company errors in forecasts with resulting excess capacity," there is "no incentive for company planners to adopt a more responsible and reliable posture in their forecasts . . ."[148] Excess capacity adjustments "encourage utilities to fine-tune their planning methodologies to more accurately predict demand and to promote a better match between load growth and generating capacity expansion."[149] "[A]fter ascertaining the level of demand, a company must construct capacity both of the type and at the time necessary. Making a company bear the risk of overconstruction furthers this goal."[150]

With regard to cost allocation, Colton states:

> The most common method used by public utility commissions is to adjust a company's weighted rate of return. [footnote omitted] A company's weighted rate of return is the aggregation of its interest on debt, its return on common equity, and its return on preferred equity. The return adjustments have varied widely in severity. . . . [T]he Pennsylvania commission completely excluded Philadelphia Electric Company's surplus investment from rate base, but allowed the company to recover the costs of depreciation, operation and maintenance, and fuel stocks from ratepayers. [citing *Philadelphia Elec. Co.*, 37 Pub. Util. Rep. (PUR) 4th 381, 389 (Pa. Pub. Util. Comm'n 1980)] In this manner, a sharing of the burden of the excess was accomplished with investors "paying" the return *on* equity (*i.e.*, the profit) and ratepayers paying the return *of* equity (*i.e.*, the depreciation).
>
> Some commissions have limited excess capacity adjustments to a company's return on common equity. The North Dakota [citing *Otter Tail Power Co.*, 44 Pub. Util. Rep. (PUR) 4th 219, 228 (N.D. Pub. Serv. Comm'n 1981)] and South Dakota [citing *Northern States Power Co.*, No. F-3382, slip op. at 42 (S.D. Pub. Serv.

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147 *Id.* at 1147.

148 *Id.* at 1152, citing *Philadelphia Elec. Co.*, 31 Pub. Util. Rep. (PUR) 4th 15, 26 (Pa. Pub. Util. Comm'n 1979).

149 *Id.* at 1152, citing *Iowa Pub. Serv. Co.*, No. RPU-80-65, at 13 (Iowa State Commerce Comm'n, Order on Rehearing, issued Apr. 30, 1982) (internal quotations omitted).

150 *Id.* at 1152.

> Comm'n Dec. 15, 1981)] commissions held that shareholders would be allowed no return on equity in excess plant.[151]

With regard to apportionment of plant, Colton states:

> Deciding on a cost allocation method does not provide a regulator with an excess capacity adjustment. A regulator must also identify the plants that will not be charged to ratepayers. . . The Pennsylvania commission . . . apportioned the surplus to the "least economical units" and eliminated the depreciated original cost of those units from rate base [citing *Philadelphia Elec. Co.*, 37 Pub. Util. Rep. (PUR) 4th 381, 388 (Pa. Pub. Util. Comm'n 1980)]. The South Dakota commission made its adjustment based on the company's average net investment [citing *Northern States Power Co.*, F-3382, slip op. at 42-43 (S.D. Pub. Serv. Comm'n Dec. 15, 1982)]. This method aggregates a company's total investment, including all types and all vintages of capacity, and applies the equity reduction to the average cost per megawatt. The Iowa commission also adopted this method [citing *Iowa Power & Light Co.*, Nos. RPU-78-27, RPU-78-30, RPU-80-36, slip op. at 12-13 (Iowa State Commerce Comm'n Feb. 27, 1982); *Iowa-Illinois Gas & Elec.* Co., 46 Pub. Util. Rep. (PUR) 4th 616, 622 (Iowa State Commerce Comm'n 1982); *Iowa Pub. Serv. Co.*, 46 Pub. Util. Rep. (PUR) 4th 339, 370-71 (Iowa State Commerce Comm'n 1982)].[152]

With regard to the measurement of the excess, Colton states that "[a] third key issue is how much generation capability must be apportioned as 'excess.' The most common method is to compare total generating capacity to the sum of peak demand plus an adequate reserve margin."[153]

Colton concludes as follows:

> The better-reasoned regulatory response to the excess capacity issue has been the adoption of a cost-sharing approach. Such an action allocates the financial responsibility for surplus generating capability between investor and customer. Even if the company was reasonable in building a plant, ratepayers should not be

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151 *Id.* at 1153-1155.

152 *Id.* at 1157-1158 (footnote omitted).

153 *Id.* at 1160 (footnotes omitted).

> completely responsible for the costs of unused capacity. Excess capacity adjustments have generally been effected through modifications to a company's weighted rate of return.[154]

As mentioned above, in *Duquesne*, the U.S. Supreme Court examined the constitutionality of the "used and useful" concept when applied to deny cost recovery. The Court considered a Pennsylvania law requiring that rates for electricity be fixed without consideration of a utility's expenditures for facilities which were planned but never built, even though the expenditures were prudent and reasonable when made. The Court held that such a law did not "take" the utilities' property in violation of the Constitution. The Court further held that a state scheme of utility regulation does not "take" property if it disallows recovery of capital investments that are not "used and useful" in service to the public. The Court affirmed a Pennsylvania Supreme Court's decision holding that Pennsylvania law prohibits recovery of the costs in question whether such recovery is accomplished through inclusion in the rate-base or through amortization.

Also as mentioned above, a number of state cases hold that, where there is "excess capacity" on the system, the facilities representing the excess capacity may be excluded from the rate base. For example, in *Iowa Public Service Co.*,[155] the commission took the position that the prudent investment test was inadequate to address excess capacity because it failed to provide utility management with an incentive constantly to rethink investment decisions in light of new developments.[156] The commission balanced the interests of investors and consumers and established a formula where the utility's rate of return is reduced by an amount proportionate to its excess capacity.[157]

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154 *Id.* at 1162 (footnote omitted).

155 46 Pub. Util. Rep. 4th (PUR) 339 (Iowa Commerce Comm'n 1982).

156 *Id.* at 367-68.

157 *Id.* at 370-71.

Further, in *Montana-Dakota Utilities Co.*,[158] the North Dakota Commission disallowed a portion of the utility's investment in a new coal-fired generating plant previously certified by the commission because it created excess capacity on the system.[159] Although the excess capacity was attributable to an unanticipated decline in demand, the portion of the investment corresponding to the excess capacity was denied inclusion in rate base.[160]

Furthermore, in *Philadelphia Electric Company v. Pennsylvania Public Utilities Commission*,[161] the Commonwealth Court of Pennsylvania affirmed the above-mentioned decision of the Pennsylvania commission (*i.e.*, *Philadelphia Elec. Co.*, 37 Pub. Util. Rep. (PUR) 4th 381 (Pa. Pub. Util. Comm'n 1980)), to exclude excess capacity facilities from rate base with regard to the return on the investment and opined that a facility prudently constructed may be excluded from the rate base if the facility will not be "used and useful" in rendering service to the public. The Pennsylvania commission identified as the facilities most representative of excess capacity those which were the least economical and deducted the depreciated original cost of these facilities from the claimed rate base. The commission specified that it was not questioning the company's decisions to build the facilities. Rather, the basis for its order was the finding that, to the degree that there is excess capacity on the system, there are facilities that are not "used and useful" in rendering service to rate payers.[162]

Therefore, there are various ways for the return on equity to be adjusted in order to account for non-"used and useful" assets or excess capacity on the system.

158 44 Pub. Util. Rep. 4th (PUR) 249 (N.D. Pub. Serv. Comm'n 1981).

159 *Id.* at 254.

160 *Id.* at 255-256.

161 61 Pa. Commw. 325, 433 A.2d 620 (1981).

162 *Id.* at 327-331. Additionally, TransCanada has suggested that U.S. state decisions are relevant in considering its Application. *See, e.g.*, TransCanada's Responses to Round 1 Information Requests, Page 3 of response to NEB 2.34.

In Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Cancelled Plants and Excess Capacity*, mentioned above, the author asserts that utilities should not be rewarded for wasteful investment decisions.[163]

Pierce states that,

> [h]istorically, the used and useful test was employed primarily to exclude from the rate base investments in plants that are not yet operable, investments in assets that provide benefits exclusively to parties other than consumers of regulated services, and investments in plants that are no longer used because of obsolescence, chronic mechanical failure, or an order from a government agency requiring termination of operations for a sustained period of time. Unlike the prudent investment test, the used and useful test does not make the finding of fault a prerequisite for the exclusion of an asset from rate base.[164]

Pierce adds that "a plant can be the product of prudent decisions but not be used and useful because of factors beyond the control of the utility or because of changes in conditions beyond the reasonable foresight of the utility."[165] Therefore, in most jurisdictions the "used and useful" test operates as a basis "for excluding an asset from rate base."[166]

Specifically with regard to excess capacity, Pierce states:

> [o]bviously, inclusion of all excess capacity in rate base provides no check on the regulatory incentive to overinvest in capital assets. *If the used and useful test is not available to restrain the utilities from responding to this incentive*, the commission will have no tools except whatever direct control it is able to exert over investment decisions through its power to certify and cancel plants and its power to exclude plants from rate base through the prudent investment test. Neither provides a reliable means of limiting the

[163] Pierce at 506.

[164] *Id.* at 512-513, citing *Pennsylvania Pub. Util. Comm'n v. Metropolitan Edison Co.*, 29 Pub. Util. Rep. 4th (PUR) 502, 505-08 (Pa. P.U.C. 1979).

[165] *Id.* at 513, citing *Pennsylvania Pub. Util. Comm'n v. Metropolitan Edison Co.*, 37 (Pub. Util. Rep.) 4th (PUR) 77, 86 (Pa. P.U.C. 1980).

[166] *Id.*

> ability of utilities . . . to respond to the regulatory incentive to overinvest in capital-intensive capacity.[167]

Pierce adds that the "most promising approach to the difficult problem of regulatory treatment of excess capacity . . . [is to] reduc[e] a utility's rate of return by an amount proportionate to the amount of excess capacity on the utility's system."[168]

VII. CONCLUSION

Q63. Does this conclude your written evidence?

A63. Yes.

Dena E. Wiggins

Dena E. Wiggins

[167] *Id.* at 540 (emphasis added).

[168] *Id.* at 540-541, citing *Iowa Public Service Co.*, 46 Pub. Util. Rep. 4th (PUR) 339 (Iowa Commerce Comm'n 1982) (explained in more detail below).