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Deploying IGCC in This Decade With 3Party Covenant Financing

Volume II

William G. Rosenberg, Dwight C. Alpern, Michael R. Walker

Energy Technology Innovation Project
a joint project of the
Science, Technology and Public Policy Program
and the
Environment and Natural Resources Program
Belfer Center for Science and International Affairs

2004 - 08
JULY 2004

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John F. Kennedy School of Government
Harvard University

July 2004

CITATION INFORMATION

This paper may be cited as: Rosenberg, William G., Dwight C. Alpern and Michael R. Walker. "Deploying IGCC Technology in this Decade with 3 Party Covenant Financing: Volume II." ENRP Discussion Paper, Discussion Paper 2004-07. Cambridge, MA: Belfer Center for Science and International Affairs, Kennedy School of Government, Harvard University, July 2004. Comments are welcome and may be directed to William Rosenberg; e-mail William_Rosenberg@KSG.Harvard.edu. Electronic copies of this report are available at: www.ksg.harvard.edu/bcsia/enrp

PROJECT SPONSORS

Department of Energy, National Energy Technology Laboratory

Environmental Protection Agency, Office of Air and Radiation

National Commission on Energy Policy

John F. Kennedy School of Government

Center for Clean Air Policy

Hogan & Hartson LLC

AUTHORS

William G. Rosenberg

79 John F. Kennedy Street
Center for Business & Government
Belfer Center for Science & International Affairs
Kennedy School of Government, Harvard University
919.601.0563
wrosenberg@e3ventures.com

Dwight C. Alpern

Research Director
Legal & Regulatory Issues
202.343.9151
Alpern.Dwight@epa.gov

Michael R. Walker

Research Director
Economic & Technical Issues
720.842.5345
mwalker@e3ventures.com

ACKNOWLEDGEMENTS

The authors of this report would like to offer the deepest appreciation to all of the extraordinary people and organizations that provided support, assistance, and advice. The project would not have been possible without the counsel of many experts, or the generous time and resource contributions of a number of forward thinking people and organizations.

First and foremost, our deepest appreciation to the organizations that sponsored and supported the effort, including the Department of Energy, National Energy Technology Laboratory; Environmental Protection Agency, Clean Air Markets Division; National Commission on Energy Policy; John F. Kennedy School of Government; Center for Clean Air Policy; and Hogan & Hartson law firm. Without the assistance from these groups, the project would never have gotten off the ground or made its way to completion.

Thank you to all of our friends and colleagues at the John F. Kennedy School of Government. Our deepest appreciation to Professor Henry Lee, Jaidah Family Director, Environment and Natural Resources Program for his tireless assistance in steering the project and ensuring an organized and thorough peer review. Thank you to Professor John Holdren, Teresa and John Heinz Professor of Environmental Policy, Director, Science, Technology and Public Policy Program for his encouragement, advice, and introductions. Thank you also to Dr. Kelly Sims Gallagher, Director, Energy Technology Innovation Project who was an important, helpful resource for the project and to Professor Roger Porter, IBM Professor of Business and Government, Center for Business and Government for his counsel. We would also like to thank the many other people at the Kennedy School that worked with and supported the project, including Elizabeth Bulette, Dawn Hilali, Jason Jennaro, Jo-Ann Mahoney, Swaminathan Narasimhan, John Neffinger, Ann Stewart, and Amanda Swanson.

Special thanks also to Robert Williams, Senior Research Scientist, Princeton University for sharing his expertise and advice and for assisting with several critical and difficult technical aspects of the report. We are also grateful for the encouragement and advice of David Hadley, Commissioner, Indiana Utility Regulatory Commission, Kim Wissman, Deputy Director, Utilities Department, Public Utilities Commission of Ohio, David Hawkins, Program Director, Climate Center, Natural Resources Defense Counsel and Jeff Cohen, White House Taskforce on Energy Project Streamlining.

The project would also like to offer special thanks to Mildred Perry and Gary Stiegel of the National Energy Technology Lab for their generous support and advice from the outset of the project, as well as Massood Ramazaan of SAIC for helping the project find its way. Thanks also to Jim Childress, Gasification Technology Counsel, for sharing his expertise and for connecting the project with the many knowledgeable people in the gasification industry. Thank you to Darlene Radcliffe and her colleagues at Cinergy for sharing their knowledge, to Patrick Raher, Senior Environmental Partner, Hogan & Hartson for his expertise and assistance with many complex legal and political matters, and to Don Elliott, Adjunct Professor of Law, Yale Law School for his considered advice.

Finally, thanks to all who attended the February 11, 2004 workshop to discuss the draft report and offer comments and suggestions. Although the arguments and ideas contained in this work are strictly those of the authors and do not necessarily represent the views of the sponsors or any of the other experts consulted along the way, the authors are well aware that without all of the advice, guidance, and support, successful completion would not have been feasible. Thank you to our families who put up with extended work hours and everyone that helped this project along as it endeavored to make a contribution in a very important national energy and environmental policy arena.

FOREWORD

These two volumes emanate from fourteen months of research, discussion and countless drafts. The three authors, William Rosenberg, Dwight Alpern, and Michael Walker, conducted meetings with key players, including officials from both the federal and state government, representatives of the power, engineering, coal and chemical industries, environmental groups and academic experts. We are especially grateful for the cooperation of the Carbon Mitigation Initiative at Princeton University and two of its leaders, Robert Socolow and Robert Williams, and for the continuing advice from the MIT Laboratory for Energy and the Environment.

Both of these volumes have been extensively peer reviewed by a team of experts, including faculty at Harvard, Yale, and Princeton. The authors have consulted with officials from the Electric Power Research Institute (EPRI), Center for Clean Air Policy (CCAP), and the National Association of Regulatory Utility Commissioners (NARUC). The authors also benefited from a workshop held at the John F. Kennedy School in February, 2004. Over eighty experts from across the country participated in a discussion on opportunities to overcome the financial and political challenges confronting the deployment and commercialization of Integrated Gasification Combined Cycle technologies (IGCC), (see the ENRP rapporteur's report: “Workshop on Integrated Gasification Combined Cycle: Financing and Deploying IGCC Technologies in this Decade,” #2004-06).

These reports are part of a three-year program in the Kennedy School's Energy Technology Innovation Project (ETIP), a joint effort of the Environment and Natural Resources Program (ENRP) and the Science, Technology and Public Policy Program (STPP). ETIP has fostered extensive work on the obstacles and opportunities for development and utilization of IGCC technologies in China and India, as well as in the United States.

These efforts are stimulated by three policy imperatives: the need to increase the use of indigenous coal supplies and to meet a growing demand for electricity; the need to clean up our air, and reduce the threat of global climate change; and the need to address the nation's energy security. These reports provide a blueprint of how the United States might take the initial steps to commercially deploy IGCC technology to significantly improve our air, economy, and national interest.

We are very grateful for the support of the National Commission on Energy Policy, the Department of Energy, the Environmental Protection Agency, the Hewlett Foundation, the Packard Foundation, the Roy Family Fund, and the hundreds of experts who have generously given the authors the benefit of their advice and counsel.

John Holdren and Henry Lee
Co-chairs, Energy Technology and Innovation Project

REPORT ORGANIZATION

The paper is divided into two volumes. Volume I describes IGCC technology, why it is an important advanced clean coal technology for generating electricity, the hurdles to near-term deployment, the 3Party Covenant financing and regulatory program to stimulate near-term IGCC deployment, and how the 3Party Covenant improves the economics of IGCC technology to make it competitive. Appendix A of Volume I outlines the components of federal legislation that are needed to implement the 3Party Covenant.

Volume II provides a detailed legal analysis of the federal and state authorities and regulatory mechanisms for implementing the 3Party Covenant, including a review of traditional electric utility regulatory systems, the current regulatory systems in 5 specific states, and a model regulatory mechanism for review and approval of IGCC project costs under the 3Party Covenant.

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VOLUME I

6.0. INTRODUCTION

Volume I of this report provides background on IGCC as a clean coal technology and discusses why it is an important electricity generation technology that yields energy, environmental, national security, and economic development public benefits and what economic and financing hurdles exist to near-term, commercial IGCC deployment. Volume I also describes in detail the 3Party Covenant financing and regulatory program, including the economics of IGCC under the 3Party Covenant and the components of federal legislation recommended for implementation of the program.

This Volume II provides background on the legal and regulatory framework for implementing the 3Party Covenant and addresses important implementation issues regarding: state PUC regulatory authority, procedures, and policies; application of the 3Party Covenant in states with more traditional utility regulatory systems and states with retail electric competition; and the interaction of state PUC and FERC jurisdiction.

In particular, Section 7.0 (the first section of Volume II) begins with an overview of the traditional electric industry regulatory system and how it impacts the allocation of risk in the development of new electricity generating plants, such as new IGCC plants. This section provides a foundation for understanding how utility regulatory commissions' ratemaking and cost recovery procedures and policies affect the allocation of construction, operating, and market risk between investors and ratepayers. A critical aspect of the 3Party Covenant is that it re-allocates risk among the federal government, investors, and ratepayers in a manner that reduces capital costs (and thus the cost of electricity produced) and creates a risk tolerant investment structure, while assuring protection of the interests of ratepayers and the federal loan guarantor.

Section 8.0 provides a detailed review of the electric industry regulatory systems in three states with a more traditional regulatory approach (Indiana, Kentucky, and New Mexico) and two states with retail electric competition (Ohio and Texas). This detailed review highlights a number of important legal requirements and policies (e.g., as applicable, the review of costs and determination of rates, the treatment of cancelled plants, the use of adjustment clauses, and special provisions for different types of generation) that affect the treatment and pass-through of costs, and the allocation of risks, associated with developing new electricity generating plants. The discussion focuses on aspects of each state's regulatory system that will make the system suitable for implementing the 3Party Covenant and those aspects that will need clarification or modification (e.g., through state legislation) for 3Party Covenant implementation.

Section 9.0 provides a model state PUC regulatory mechanism for review, approval, and recovery of IGCC project costs. This mechanism is at the heart of the 3Party Covenant financing and regulatory program. It is through state PUC review, approval, and recovery processes that an assured revenue stream is established for IGCC project costs in order to reduce the risk (and cost) of the federal loan guarantee under the 3Party Covenant. Several scenarios for development of new IGCC plants are described and used in discussing the application of the model regulatory mechanism. This section also describes the state statutory changes that may be necessary for application of the model regulatory mechanism. Finally, this section discusses FERC rate jurisdiction over new IGCC plants and the potential interaction between the FERC and a state PUC in the review, approval, and recovery of IGCC project costs under the 3Party Covenant.

7.0. TRADITIONAL ELECTRIC INDUSTRY REGULATORY SYSTEM AND EFFECT ON ALLOCATION OF INVESTMENT RISK OF NEW IGCC PLANTS.

7.1. Description of traditional electric industry regulatory system.

What follows is a summary description of the traditional approach to regulation of the electric industry. While the structure of the electric industry has become more complicated with, inter alia, the increased role of merchant generators, most, but not all states, continue to use a more traditional approach to regulating the electric industry. However, in some states and in varying degrees, the electric industry has been significantly restructured, and competition has been introduced for retail electricity generation and sales. Section 8.0 below discusses in detail the regulatory systems in five example states, three with more traditional regulatory systems and two with retail competition. Included in that discussion are detailed citations to statutes and administrative and judicial decisions that support the more summary discussion in this Section 7.0. The purpose of discussing traditional and competitive regulatory systems is to develop an understanding of the effect that they have on the allocation of electricity-generation investment risk between investors and ratepayers and to examine the legal authority and precedents for allocating such risk.

7.11. Treatment of Companies as Natural Monopolies.

The business of generating, transmitting, and distributing electricity to the public has traditionally been regarded as a natural monopoly. Generation, transmission, and distribution were believed to be most efficiently provided by a single company that was the sole provider of these services for the public in an assigned geographic area. See Transmission Access Policy Study Group v. Federal Energy Regulatory Commission, 225 F.3d 667, 681 (D.C. Cir. 2000), aff'd sub nom. New York v. Federal Energy Regulatory Commission, 535 U.S. 1 (2002).

Under this approach, a state grants a single company the exclusive right to sell and distribute electricity to consumers in a specified service area and requires that company to undertake the obligation to meet the electricity needs of all such consumers, including both existing and future consumers. The corporate structure of the company can vary. One possible structure is a single corporation handling all of these activities for a given service area. Another possible structure is a parent (or holding) company with subsidiary operating companies, each of which handles generation, transmission, and distribution within a particular service area generally in a specific state.

In light of the utility's exclusive right and obligation to meet consumers' electricity needs in the service area, the state generally regulates (through a state PUC) the generation, retail sale, and distribution of electricity by the utility. Such regulation encompasses setting of electric rates and may also include authorization to construct facilities. Rural electric cooperatives (most of which are nonprofit cooperatives financed through the Rural Utilities Service of the U.S. Department of Agriculture under the Rural Electrification Act) and municipal utilities are also generally given the exclusive right and obligation to meet consumers' electricity needs in their respective service areas. In general, the municipality (rather than the state PUC) has jurisdiction over the rates for municipal utilities. Rural electric cooperatives may or may not be under state PUC jurisdiction. See Arkansas Electric Cooperative, Corp. v. Arkansas Public Service Commission, 461 U.S. 375 (1983) (upholding jurisdiction asserted by state PUC over rates, for wholesale sales to cooperative members (as well as for retail sales to consumers), of rural electric generation cooperative with federal financing).

In contrast with the regulation of generation, retail sale, and distribution of electricity at the state or local level, transmission of electricity, and sale of electricity for resale, in interstate commerce are regulated at the federal level under the Federal Power Act (16 U.S.C. 791a-828e) by the FERC.[158] Transmission Access Policy Study Group, 225 F.3d at 690-96 (describing FERC jurisdiction over transmission and wholesale sales in interstate commerce and upholding FERC's jurisdiction over unbundled retail transmission and use of multifactor test to distinguish transmission from distribution facilities); see also Northern States Power v. Federal Energy Regulatory Commission, 176 F.3d 1090 (8th Cir. 1999), cert. den., 528 U.S. 1182 (2000). (holding that FERC exceeded its jurisdiction in requiring utility to curtail provision of electricity to its retail and its wholesale customers on the same pro rata basis). For example, where one company purchases electricity from another company generating the electricity and in turn sells the purchased electricity to retail customers, the initial purchase for resale is generally subject to FERC jurisdiction, including rate review. See Federal Power Commission v. Florida Power & Lighting Co., 404 U.S. 453 (1972) (upholding FERC jurisdiction over utility generating electricity sold in same state because utility is connected with interstate transmission system). However, because the transmission and distribution system in the portion of Texas in the Electric Reliability Council of Texas (ERCOT) region of the North American Electric Reliability Council (NERC) has very limited interconnections with transmission and distribution systems in contiguous states, the FERC lacks jurisdiction over transmission and sales for resale in that portion of Texas. See City Public Service Board of San Antonio v. Public Utility Commission of

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[158] In exercising its jurisdiction over sales for resale, the FERC requires public utilities making such sales to charge just and reasonable rates, which may be either cost-based rates or market-based rates (i.e., rates reflecting prices in a competitive electricity market when such a market is shown to exist). See Section 9.5 below. In exercising its jurisdiction over interstate transmission, the FERC generally requires public utilities that own, control, or operate facilities used for transmitting electricity in interstate commerce to file open-access, nondiscriminatory transmission tariffs. See Order No. 888, 61 Fed Reg. 21,540 (1996), clarified, 76 FERC ¶ 61,009 and 76 FERC ¶61,347 (1999), on reh'g, Order No. 888-A, 62 Fed. Reg.12274 (1997), clarified, 79 FERC ¶ 61,182 (1997), on reh'g, Order No. 888-B, 62 Fed. Reg. 64688 (1997), on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group, 225 F.3d 667.

Texas, 9 S.W.3d 868, 875 n.15 (Tex. App. 2000), aff'd , 53 S.W.3d 310 (Tex. Sup. Ct. 2001).[159]

Sales for resale and transmission by rural electric cooperatives with federal financing and by municipal utilities are not subject to FERC jurisdiction. Salt River Project Agricultural Improvement and Power District v. Federal Power Commission, 391 F.2d 470 (D.C. Cir. 1968). However, the exception from FERC jurisdiction for rural electric cooperatives does not apply once they are no longer using federal financing. Golden Spread Electric Cooperative, 39 FERC ¶ 61,322 (1987), reh'g den., 40 FERC ¶ 61,348 (1987).

FERC jurisdiction over sales for resale in interstate commerce includes review of wholesale sale rates. In order to approve or set wholesale rates, the FERC must find them to be "just and reasonable." See 16 U.S.C. 824d(b) and 824e(a). Further, under the Supremacy Clause of the U.S. Constitution (art. VI, clause 2), the FERC's rate jurisdiction over sales for resale in interstate commerce is exclusive and pre-empts review by state PUCs or other state or local ratemaking authorities of the justness and reasonableness of wholesale rates. See, e.g., Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 963-66 (1986); and Sinclair Machines Products, Inc., 498 A.2d 696, 698-705 (N.H. 1985) (holding state PUC is pre-empted from denying pass-through of FERC-approved costs of cancelled nuclear plant despite state statutory bar against recovery of capital costs on construction work in progress).

Moreover, federal pre-emption is not limited to the wholesale rates themselves. Generally, matters on which the FERC makes justness and reasonableness determinations while exercising its jurisdiction over wholesale sales cannot be revisited by the state PUC in a way that results in denying pass-through (i.e., in trapping) of costs that are under FERC jurisdiction and that the FERC determines are just and reasonable. As part of its wholesale-sales jurisdiction, the FERC has the authority to review any inter-company agreement that "significantly *affects*" wholesale sales. Mississippi Industries v. Federal Energy Regulatory Commission, 808 F.2d 1527, 1542 (D.C. Cir. 1987). Consequently, a state PUC is pre-empted from finding unjust or unreasonable any costs reflected in wholesale rates, or based on inter-company agreements, approved by the FERC and from denying pass-through of these costs by wholesale purchasers to their retail customers based on such a finding.

For example, where the FERC reviewed an inter-company agreement that allocated quantities of low-cost hydroelectric power, generated and provided by a third party, between two purchasing affiliated companies, the FERC found the allocations were unfair and ordered different allocations. One of the affiliated companies made sales to its parent industrial company, while the second of the affiliated companies had retail and wholesale customers. The U.S. Supreme Court held that the state PUC had to set the

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[159] For similar reasons, the FERC lacks jurisdiction over transmission and wholesale sales in Alaska and Hawaii. See New York, 535 U.S. at 7. These two states are not further discussed in this paper.

second affiliated company's retail rates based on the FERC-determined allocations, not on different allocations that would assume a greater share of low-cost power (and thus lower power costs) for retail sales. Nantahala Power & Light, 476 U.S. at 969. The state PUC lacked the authority to assume a greater low-cost-power allocation for retail sales because that would effectively attribute a lower amount of power costs to retail sales and thereby prevent pass-through of (i.e., trap) a portion of the power costs that the FERC had approved for the affiliated companies. Id. at 970-72.

Similarly, where, after reviewing an inter-company agreement that allocated quantities of high-cost nuclear power among the operating companies in a holding company, the FERC required different allocations and set wholesale rates for the power, the allocations and rates were binding on a state PUC with jurisdiction over one of the operating companies. Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354, 372-77 (1988). In making those determinations, the FERC did not made an express finding on the prudence of the inter-company agreement or the investment in the nuclear plant because the issues, while integral to the FERC's review, were not raised. Id. at 368. The state PUC was still pre-empted from considering such prudence for the purpose of trapping the FERC-approved costs and had to allow pass-through of the nuclear plant costs resulting from the quantity of high-cost power and the rates determined by the FERC. Id. at 372-73.

However, this does not mean that state PUC rate review is entirely pre-empted in all circumstances. While the state PUC must treat, as just and reasonable, the FERC-approved wholesale rates charged by the wholesale seller, the state PUC has the authority to review the quantity of electricity contracted for or purchased at those rates by the wholesale purchaser, unless a FERC-approved agreement obligates the wholesale purchaser concerning the quantity as well as the price. For example, in Pike County Light and Power Co. v. Pennsylvania Public Utility Commission, 465 A.2d 735, 737-38 (Pa. Commw. 1983), the Court held that the state PUC could not review the wholesale rates paid for electricity resold to retail customers, but could review whether and how much electricity was prudently purchased by the wholesale purchaser and determine what amount of costs could be passed through to retail customers. Because the FERC had approved the rates, but not any particular quantity of electricity, for the sale for resale, the state PUC could consider the wholesale purchaser's alternative sources for electricity to determine what quantity was prudently purchased in the particular sale for resale. Id. at 738. Similarly, in Gulf States Utilities Co. v. Public Utility Commission of Texas, 841 S.W.2d 459, 468-71 (Tex. App. 1992), it was held that the state PUC could review a utility's prudence in entering into a wholesale purchase agreement where the utility was not otherwise obligated (e.g., under an integrated pooling agreement) to purchase the power. See also Pennsylvania Power Co. v. Pennsylvania Public Utility Commission, 561 A.2d 43, 49-53 (Pa. Commw. 1989), aff'd, 587 A.2d 312 (Pa. 1991), cert. den., 502 U.S. 821 (1991); Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Commission, 837 F.2d 600, 605-16 (3d Cir. 1988), cert. den., 488 U.S. 941 (1988); and Sinclair Machines Products, 498 A.2d at 705.

Moreover, even where a utility is obligated under a FERC-approved agreement to purchase power (i.e., capacity in a nuclear plant) so that the state PUC cannot review the prudence of the purchase, the state PUC may review the utility's prudence in retaining, rather than selling, its share of such capacity. New Orleans Public Service, Inc. v. Council of City of New Orleans, 491 U.S. 350 (1989); and New Orleans Public Service, Inc. v. Council of City of New Orleans, 911 F.2d 993, 1001-04 (5th Cir. 1990).

In summary, the scope of state PUC review is much more limited for pass-through to retail customers of plant costs reflected in the wholesale rates of the plant owner or in inter-company agreements than for direct recovery from retail customers of plant costs reflected in the retail rates of the plant owner. Yet, some prudence issues remain within the purview of the state PUC. In addition, even when the state PUC must allow eventual pass-through of FERC-approved costs to retail customers, the state PUC may apply normal rate procedures even if they result in delaying that pass-through (e.g., through suspension of proposed rate increases) and do not allow the utility to recover interest during the delay period. Arkansas Power & Light Co. v. Missouri Public Service Commission, 829 F.2d 1444, 1452-53 (8th Cir. 1987). Similarly, the state PUC may exercise its discretion to require pass-through in a general rate case or other procedure that results in delayed cost recovery, rather than in an adjustment clause. See, e.g., Kentucky West Virginia Gas Co. v. Pennsylvania Public Utility Commission, 862 F.2d 69, 73-74 (3d Cir. 1988); Public Service Co. of Colorado v. Public Utilities Commission of Colorado, 644 P.2d 933, 940-42 (Colo. 1982); and Narragansett Electric Co. v. Burke, 381 A.2d 1358, 1362-63 (R.I. 1977), cert. den., 435 U.S. 972 (1978). However, where, under state statute, a state PUC only has discretion to deny pass-through in an adjustment clause if the costs are unreasonable, the state PUC cannot deny or delay pass-through of FERC-approved costs. See Eastern Edison Co. v. Department of Public Utilities, 446 N.E.2d 684, 689-90 (Mass. 1973).

7.12. Just and reasonable rates.

Utility regulatory commissions (whether federal or state) are generally required by statute, as interpreted by the courts, to set rates for a utility that are "just and reasonable." The U.S. Supreme Court explained this requirement as follows:

> [T] he fixing of 'just and reasonable' rates [ ] involves a balancing of the investor and consumer interests...[T]he investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business...[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to

> maintain its credit and to attract capital. Federal Power Commission v. Hope Natural Gas Co. (FPC v. Hope), 320 U.S. 591, 603 (1944).

See also Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923) (holding that rates must permit a public utility to "earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties"); and Duquesne Light Co. v. Barasch, 488 U.S. 299, 315-16 (1989) (explaining that "just and reasonable" rates must balance the interests of investors and consumers). This requirement for "just and reasonable" rates is generally grounded in the federal constitutional bar against confiscatory taking of private property. See id. at 307-08.

Aside from this general standard, utility regulatory commissions are "not bound to the use of any single formula or combination of formulae in determining rates...[I]t is the result reached not the method employed which is controlling." FPC v. Hope, 320 U.S. at 602. Moreover, due to the economic complexity of the ratemaking process, there is no single "just and reasonable" rate. Instead, there is a "zone of reasonableness" within which the rate must be set. Federal Power Commission v. Conway Corp., 426 U.S. 271, 278 (1976); see also Permian Basin Area Rate Cases, 390 U.S. 747, 770 (1968) and Montana-Dakota Co. v. Northwestern Public Service Co., 341 U.S. 246, 251 (1951).

This emphasis by the U.S. Supreme Court on "end results" changed the focus of the ratemaking process. For example, before FPC v. Hope, much attention was paid to whether the property on which investors would receive a return should be valued at the original cost or the reproduction cost of property. See, e.g., Smyth v. Ames, 169 U.S. 469, 546 (1898) (requiring receipt of "fair value" of the property); McCardle v. Indianapolis Water Co., 272 U.S. 402, 411-12 (1925) (requiring receipt of fair return on reproduction costs of property); Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U.S. 276, 306-07 (1923) (dissenting opinion suggesting requirement of fair return on prudent investment); and Duquesne Light, 488 U.S. at 308-10 (explaining effect of FPC v. Hope on ratemaking process). After FPC v. Hope, none of these specific approaches was constitutionally required, and, in fact, some utility regulatory commissions consider multiple approaches to property valuation in setting just and reasonable rates.

7.13. Cost-based ratemaking.

In setting just and reasonable rates under traditional utility regulation, utility regulatory commissions apply a cost-of-service analysis. Under this approach, rates are set to allow the utility to earn total revenues sufficient to cover the cost of service approved by the utility regulatory commission. The cost of service includes: return of (through depreciation and amortization) and return on the utility's capital investment (i.e., the utility's "rate base") related to electric service; and the utility's operating expenses related to such service. For purposes of establishing the cost of service, the utility regulatory commission initially selects a representative test period, often including the twelve months just before initiation of the rate review. See NEPCO Municipal Rate Committee v. FERC, 668 F.2d 1327, 1338 (D.C. Cir. 1981), cert. den., 457 U.S. 1117 (1982) (discussing use of two test periods, i.e., the most recent 12 months and the subsequent projected 12 months). The levels of capital investment, cost of capital (except return on equity, for which the most current data are generally used), and operating expenses in the test period are evaluated by the utility regulatory commission and provide a starting point for determining what levels should be included in the cost of service and covered by the rates. The levels in the test period may be adjusted to the extent that they are determined to be unrepresentative of the future (e.g., are unlikely to continue) or to be unreasonable. See Paul Rodgers and Charles D. Gray, "State Commission Treatment of Nuclear Plant Cancellation Costs," 13 Hofstra L. Rev. 443, 447-49 (Spring 1985) (generally describing cost-based ratemaking process).

Costs related to capital.

Specifically, with regard to capital investments, the utility regulatory commission determines which investments should be included in the rate base and in what dollar amounts. In general, investments are included in the rate base to the extent that they were prudent at the time that they were made and are used and useful (i.e., actually used and not superfluous) in providing electric service. See Jonathan A. Lesser, "The Used and Useful Test: Implications for a Restructured Electric Industry," 23 Energy L. J. 349, 352 (2002).

However, the extent to which investments were prudent when made and to which they turned out to be used and useful in providing electric service may not be coincident. For example, while a utility might prudently decide to invest in a new electricity generating plant based on then-current projections of electricity demand and planning and construction costs, the plant might be cancelled before completion because of changes in projected or actual demand or construction costs. Depending on, inter alia, the applicable underlying statutory authority for setting rates, utility regulatory commissions take various approaches to addressing plant cancellations.

One approach (the "prudent investment" approach) is to include, in rate base, electricity generating plant investments that were prudent when made, regardless of whether the plant is ultimately completed and used. See William J. Baumol and J. Gregory Sidak, "The Pig in the Python: Is Lumpy Capacity Investment Used and Useful?", 23 Energy L. J. 383, 391-93 (2002). Review to determine whether an investment was prudent is generally conducted after plant construction is completed or terminated and may encompass an entire series of utility decisions, including the initial decision to build, decisions during design and construction, and decisions to delay or terminate construction. Nevertheless, the determination of prudence is based on the information that was known or reasonably should have been known at the time the particular decision was made. See Richard D. Gary and Edgar M. Roach, Jr. "the Proper Regulatory Treatment of Investment in Cancelled Nuclear Plants," 13 Hofstra L. Rev. 469, 472-84 (Spring 1985). To the extent the investment is found to be prudent and is included in rate base, the plant owner is allowed to recover both his investment and return on the investment. At least with regard to cancelled nuclear plants, utility regulatory commissions have not frequently used the "prudent investment" approach and thereby allowed recovery of both return on and return of capital. See Rodgers and Gray, 13 Hofstra L. Rev. at 452-53; and David P. Barker, "Who Pays? An Analysis of the Allocation of the Costs of Cancelled Nuclear Plants After Duquesne Light Co. v. Barasch," 50 Ohio St. L. J. 999, 1002 (Fall 1989).

A second approach (the "used and useful" approach) is to include in rate base only electricity generating plant investments that both were prudent when made and become used and useful. Under this approach, the utility regulatory commission reviews the investment decision with the benefit of some hindsight, i.e., the benefit of information that was not available when the investment decision was made. See, e.g., City of Cincinnati v. Public Utilities Commission of Ohio, 620 N.E.2d 826, 829-31 (Ohio 1993) (explaining that used and useful portion of plant is set by stipulation and prudence of that portion is determined based on knowledge at time of investment). The review is necessarily conducted after plant construction is completed and the plant is operating or after plant construction is terminated.

There is significant variation in the details of how various utility regulatory commissions apply the "used and useful" approach test to cancelled-plant investment. See Rodgers and Gray, 13 Hofstra L. Rev. at 452-67. For example, in some cases, when applying the "used and useful" test, utility regulatory commissions both exclude investment that is not used and useful from rate base and deny any recovery of the investment principal. See, e.g., Pacific Power and Light Co. v. Public Service Commission of Wyoming, 677 P.2d 799, 804-09 (Wyo. 1984), cert. den., 469 U.S. 831 (1984) (holding that cancelled nuclear plant is not used and useful property and so plant costs are not recoverable through inclusion in rate base or as operating costs, but stating that costs might be recoverable if plant were reviewed and approved by commission before commencement). By further example, some utility regulatory commissions exclude the investment from rate base but allow amortization, and thus recovery, of the investment principal (but not return on capital). See, e.g., Duquesne Light, 488 U.S. at 313 n.7; Violet v. Federal Energy Regulatory Commission, 800 F.2d 280, 282 (1st Cir. 1986); and NEPCO Municipal Rate Committee, 668 F.2d at 1333 (stating that, while "general rule" is that only "used and useful" investments are included in rate base, FERC may use any method of valuing rate base as long as result is not "unjust or unreasonable" and upholding amortization of costs of cancelled plant and exclusion of such costs from rate base). But see Jersey Central Power & Light Co. v. Federal Energy Regulatory Commission, 810 F.2d 1168, 1175-77 (D.C. Cir. 1987) (explaining that "used and useful" requirement is not constitutionally based and remanding to FERC to determine whether costs of cancelled nuclear plant should be included in rate base). With regard to cancelled nuclear plants, the majority of utility regulatory commissions have applied the "used and useful" approach, excluded the investment in the plants from rate base, and allowed at least some amortization.[160] Rodgers and Gray, 13 Hofstra L. Rev. at 452-53.

Under a third approach (the "economic used and useful" approach), which is the least frequently used approach, the utility regulatory commission includes, in rate base, plant that was prudent to build and that was initially used and useful but considers whether to continue to allow the plant in rate base in light of ongoing economic changes. Review continues even after the plant is completed and operating. The plant continues to be in the rate base only if the utility regulatory commission finds that the plant continues to be the least cost alternative for the company. See Lesser, 23 Energy L.J. at 359-63.

The "prudent investment," "used and useful," and "economic used and useful" approaches represent the spectrum of approaches used by utility regulatory commissions concerning recovery of capital (and associated return on capital) in electricity generating plants after plant construction is completed or terminated. Depending on the technology and size of an electricity generating plant, design and construction may extend over multiple months or years. Consequently, utility regulatory commissions must also consider the treatment of preconstruction and construction costs during plant construction. Some utility regulatory commissions allow preconstruction and construction costs ("construction work in progress" or "CWIP") to be added periodically to the rate base, during construction until the plant goes into service. See Public Service Co. of New Hampshire, 480 A.2d 20, 23 (N.H. 1984) (explaining that state PUC allowed CWIP in rate base for ongoing nuclear plant construction until prohibited by state legislature). In contrast, some utility regulatory commissions do not allow any preconstruction and construction costs in the rate base until the plant is completed and is in use. The return on capital ("allowance for funds during construction" or "AFUDC") for such costs during construction accrues, and must be carried by the investors, until the plant is in use and becomes used and useful. At that point, the total accrued return on capital during construction is added to the rate base, along with the preconstruction and construction costs of the plant. See Cities for Fair Utility Rates v. Public Utilities Commission of Texas, 924 S.W.2d 933, 935-36 (Tex. 1996); and Kentucky Utilities v. Federal Energy Regulatory Commission, 760 F.2d 1321, 1325 (D.C. Cir. 1985). Some utility commissions have allowed AFUDC to continue to accrue after the plant begins operating and until new rates recovering the cost of the plant actually go into effect. Kentucky Utilities, 760 F.2d at 1326. However, accrual of AFUDC may be suspended while construction is interrupted. See, e.g., Columbus Southern Power Co. v. Public Utilities Commission of Ohio, 620 N.E.2d 835, 842-43 (Ohio 1993).

[160] In a few cases, when the plant investment was excluded from rate base and was amortized, the utility regulatory commission allowed the utility to recover "carrying charges" on the unamortized amounts. If the carrying charges equal the utility's allowed rate of return, this treatment is essentially equivalent to including the plant investment in rate base. Rodgers and Gray, 13 Hofstra L. Rev. at 457 n.105.

Once the rate base is established, the utility regulatory commission must determine a reasonable level for return on capital. The return on capital reflects the anticipated return and risks to the investors providing the capital for the utility and varies depending on the manner in which the capital is obtained (e.g., through the sale to investors of common stock, preferred stock, or long-term debt). Long-term debt may be unsecured (i.e., based on the overall credit of the company issuing the debt), secured (i.e., based both on the overall credit of the company and on a mortgage lien on specified assets of the company), or project-financed (i.e., non-recourse to the company and based on a mortgage on the specific project for which the debt proceeds are used). In general, interest on long-term debt must be paid before dividends on common or preferred stock, and, in the event of bankruptcy, debt holders must be paid off before shareholders. Consequently, long-term debt is considered a less risky form of investment. Preferred stock is considered less risky than common stock because the preferred stock specifies the level of the dividends, payment of such dividends has priority over payment of dividends on common stock, and preferred stock generally outranks common stock in bankruptcy. See Energy Industrial Center Study, Dow Chemical Co. Environmental Research Institute of Michigan, Townsend-Greenspan and Co., Inc., and Cravath, Swaine and Moore, at 432-44 (National Science Foundation June 1975) (discussing the distinctions between debt and equity and the limitations on issuance of debt).

The utility regulatory commission must determine what capital structure (i.e., what proportions of common stock, preferred stock, and long term debt), and what costs of common stock, preferred stock, and long-term debt, to use in determining the utility's return on capital. Generally, utility regulatory commissions use the utility's actual capital structure during the test period and determine the cost of long-term debt and preferred stock by looking at the average, actual cost of existing debt and preferred stock for the test period. The cost of common stock is generally determined by evaluating the return currently required by prospective purchasers of common stock, and various methodologies are used to estimate currently required return. However, some utility regulatory commissions adjust the capital structure to reflect the parent company's capital structure and cost of capital, rather than the structure and costs of the subsidiary utility. See, e.g., General Telephone Co. of Southwest v. Corporation Commission, 652 P.2d 1200, 1205-6 (N.M. 1982). Further, utility regulatory commissions sometimes assume a hypothetical "optimal" (i.e., least cost) capital structure for the utility and determine the costs of common stock, preferred stock, and long-term debt based on that capital structure. See, e.g., Zia Natural Gas Co., 998 P.2d 564, 567-68 (N.M. 2000); Northern Carolina Utilities v. FERC, 42 F.3d 659, 663-64 (D.C. Cir. 1994); and Southern Bell Telephone Co v. Louisiana Public Service Commission, 118 So.2d 372, 380-82 (La. 1960).

In addition to covering return on capital, cost-based rates cover return of capital (i.e., depreciation or amortization of the utility's capital investments). The utility regulatory commission must determine the number of years over which capital investments are depreciated or amortized for purposes of setting rates.

Costs related to operation.

Cost-based rates also cover the utility's operating costs. Operating costs include operation and maintenance (e.g., labor, maintenance materials, administrative support, consumable supplies, and waste disposal), fuel and purchased power, and taxes. Coverage of these costs, of course, may affect investors' return on capital since these costs generally must be paid before any return on equity is actually realized. As with return on capital, utility regulatory commissions generally use actual costs during the test period as a starting point for determining the operating costs to be included in the rates. Test period operating costs may be adjusted in order to ensure that they are representative of future operations. These costs may also be reviewed to determine whether they are reasonable and reasonably related to electric service and may be disallowed if they are not. Generally, operating costs must be disallowed based on evidence of insufficient relationship to electric service or of inefficiency, improvidence, or negligence on the part of the utility, rather than simply on the utility regulatory commission's substitution of its own judgment for that of the company management. <u>See, e.g.,</u> <u>Indiana Gas Co. Inc. v. Office of Utility Consumer Counselor</u>, 675 N.E.2d 739, 744 (Ind. Ct. App. 1997). <u>See also</u> <u>Cleveland Electric Illuminating Co.</u>, 99 PUR4th 407, 445, 1989 WL 418554 (PUCO Jan. 31, 1989), <u>cause dismissed,</u> <u>Concerned Citizens of Lake County. v. Public Utility Commission of Ohio</u>, 545 N.E.2d 899 (Ohio 1989) (explaining that presumption of reasonableness of operating costs is necessary to limit issues in order to make state PUC review process workable); and Robert L. Swartwout, "Current Utility Regulatory Practice From a Historical Perspective", 32 Nat. Resources J. 289, 327-28 (1992) (stating that prudence review is conducted after a company management decision is made in order to avoid substituting commission judgment for management decision-making, but that current practice is to put the burden of proof of prudence on the utility once a prudence issue is raised).

Rates are not constantly updated, but generally stay in effect until the utility requests, and is allowed to charge, new rates or until the utility regulatory commission initiates, and completes, a review of the existing rates. In some jurisdictions, rates requested by the utility company are suspended for a period of time, after which they may be charged subject to review and refund. In other jurisdictions, requested rates cannot go in effect at all until after regulatory review is completed. Moreover, whether initiated by the utility or the utility regulatory commission, the ratemaking process takes time to complete, and the test-period cost data on which final rates are based may become outdated in the meantime. In addition, in some jurisdictions, limitations exist on how frequently rate-increase requests may be filed. As a result, rates may stay in effect for significant periods of time, and there may be a significant lag between changes in operating costs (or cost of capital) and changes in rates to reflect such changes in costs. The degree of regulatory lag is reduced to the extent that rate changes are allowed to go into effect subject to refund.

In order to reduce the effect of regulatory lag and achieve a closer match of revenues and costs, utility regulatory commissions often allow certain operating costs (primarily fuel costs and purchased power costs) to be included in rates through an adjustment clause, i.e., a formula that reflects ongoing changes in these costs, rather than at a fixed level based on test period costs. There are various ways to design a fuel or purchased power adjustment clause. See Public Service Co. of New Hampshire v. Federal Energy Regulatory Commission, 600 F.2d 944, 947-49 (D.C. Cir. 1979), cert. den., 444 U.S. 990 (1979) (describing "cost of service" fuel adjustment clause, whose purpose is recovery of actual fuel costs, and "fixed rate" fuel adjustment clause, which does not necessarily reflect accurately actual fuel costs). Under one possible approach, the difference in fuel or purchased power costs for a given future period (e.g., the next quarter) from a baseline level already reflected in the general rates is paid by each customer as an estimated per-kilowatthour charge calculated using recent costs and projected kilowatthours of electricity sales. In addition, the customer's per-kilowatthour charge reflects an adjustment to correct for any difference between the recent and actual costs for the immediately prior period (e.g., the prior quarter) and any difference between projected and actual electricity sales for that period. In some cases, a utility regulatory commission may expand the use of adjustment clauses to encompass the entire cost of service so that the entire rate is expressed as a formula and varies with changes in elements of the cost of service beyond simply fuel or purchased power costs. See Public Utilities Commission of California v. Federal Energy Regulatory Commission, 254 F.3d 250, 254 (D.C. Cir. 2001).

7.2. Effect on allocation of electricity generation investment risk.

What follows is a qualitative analysis of the effect of the traditional regulatory system on the allocation of the risk of investment in new electricity generating projects (such as new IGCC plants).[161] For purposes of this qualitative analysis, it is useful to subcategorize investment risk into construction risk, operating risk, and market risk. "Construction risk" is defined as the risk that the project construction will not be completed. Plant cancellation may result, for example, from problems with new technology or design, cost overruns, or declines in demand forecasts. "Construction risk" is also defined to include the risk that, if completed, the plant construction will not be within scheduling or cost targets. "Operating risk" is defined as the risk that the completed project will not achieve

[161] The discussion of risk of investment in, and recovery of project costs of, new IGCC plants applies to all three categories of IGCC plants discussed in Sections 3 and 6 above: i.e., new IGCC plants located on greenfield sites; new IGCC plants located on the sites of, and replacing (repowering), existing pulverized coal plants; and new gasification islands and other equipment added to, and refueling, existing natural gas combined cycle electricity generation equipment.

long-term operational benchmarks, e.g., a minimum level of plant availability or maximum level of generation when the plant is available. Operating problems may result, for example, from problems with new technology or design or from poor operation and maintenance. Both construction and operating risk reflect, at least in part, the technology risk of the type of plant involved and may result in the need to increase electricity generation at, or purchase of electricity from, other sources of electricity in order to meet demand. "Market risk" is defined as the risk that the electricity generated by the operating plant will not be sold at prices that cover capital and operating costs of the plant. The inability to cover costs may result from a reduction in demand or market price or increases in operating costs such as fuel.

7.21. Construction and operating risk.

The inability to complete or operate a new electricity generating plant threatens the recovery of capital investment in the plant and associated return on capital. Such recovery is also threatened to some extent if plant completion is not within scheduling or cost targets. The allocation of construction and operating risk is particularly important for new IGCC plants because they use a capital-intensive technology with which there is relatively limited commercial-scale experience.

Risk allocation when plant is owned by utility.

When the new plant is owned by a company subject to traditional utility regulation, the allocation of construction and operating risk associated with the plant depends largely on the utility regulatory commission's approach to setting, for purposes of cost-based ratemaking, the rate base used in determining return of and on capital. As discussed above, utility regulatory commissions use various approaches in determining rate base.

Under the "prudent investment" approach of including, in rate base, plant investment that is prudent when made regardless of whether the plant is ultimately completed and used, investors bear the risk that utility regulatory commission may determine that the initial decision to invest the capital involved (or a subsequent decision concerning the investment) was imprudent. Ratepayers bear the risk that the plant, which was prudent to construct at the time of the initial and subsequent investment decisions, may not be completed (e.g., due to factors arising after such decisions were made) or, even if prudently completed, may not meet long-term operational benchmarks. Ratepayers also bear the risk of cost overruns where a plant that was prudent to construct at the time of the initial investment and is prudently completed turns out to cost more than originally projected. Ratepayers similarly bear the risk of higher costs for substitute power if, as a result of prudent decisions, such plant takes longer to complete than scheduled. The timing of the utility regulatory commission's prudence review relative to the timing of the investment determines when risk is put on ratepayers. Generally, the review -- and thus the imposition of risk on ratepayers -- occurs after plant construction is completed or terminated.

To the extent that the utility regulatory commission allows preconstruction and construction costs for prudent projects to be included (as construction work in progress or CWIP) in the rate base before plant completion, there is further allocation of construction and operating risk to ratepayers and that imposition of risk on ratepayers occurs sooner. This is because investors' recovery of construction costs from ratepayers begins earlier and the investors' need for construction loans is reduced. The earlier recovery of cost of capital during construction (which may span two or more years in the case of large, technologically complex plant like an IGCC plant) reduces the accrued cost of capital (in the form of allowance for funds during construction or AFUDC) added to the rate base.

In contrast, under the "used and useful" approach of including in rate base only electricity generating plant investments that both are prudent when made and are actually used and useful, the investor bears more construction and operating risk, than under the "prudent investment" approach. Under the "used and useful" approach, investors bear the risk of an imprudence finding based on conditions when investment decisions were made, the risk that factors arising after those decisions may make the plant investment no longer prudent, and the risk that the completed plant will not operate properly. However, even under this approach, these risks are shared to some extent with ratepayers to the extent the utility is allowed to amortize plant investment that is excluded from rate base. Application of the "used and useful" approach also generally means that investors cannot begin recovering construction costs until after plant completion. Because plant under construction is not yet used and useful, construction work in progress is often not allowed in rate base under this approach. In some jurisdictions, exceptions exist, e.g., for construction of emission controls, but the revenue from including such construction work in progress in the rate base may have to be refunded to ratepayers if the plant is not completed. Ratepayers still bear the risk of cost overruns if the plant was prudently completed but costs more than projected, if the increased costs are found to be reasonable. Ratepayers similarly bear the risk of higher costs for substitute power if completion of such plant was prudently delayed.

Some utility regulatory commissions have explicitly recognized the resulting increased risk to investors under the "used and useful" approach and have therefore allowed companies a higher return on common equity than in the absence of such risk. This higher return is supposed to compensate investors for the enhanced risk that they will be required to write off investments, e.g., in electricity generating projects that are cancelled or that never operate properly.

Under the "economic used and useful" approach, the utility regulatory commission considers on an ongoing basis whether to continue allowing, in the rate base, plant that was prudent to build and that was initially used and useful. Under this approach, plant continues to be allowed in the rate base only if the utility regulatory commission finds that the plant continues to be the least cost alternative for the company. This approach provides the utility regulatory commission with additional, ongoing opportunities to review investment decisions and puts additional risk on the investors. Investors, not ratepayers, bear the risk that more economic alternatives become available after the plant is prudently constructed and is initially used and useful.

Under the "prudent investment" approach, "used and useful" approach, or "economic used and useful" approach, other entities may assume some of the construction or operating risk. In particular, the engineering, procurement, and construction (EPC) contractor may be willing to guarantee plant completion (e.g., in terms of time, availability schedule, and total cost), supported by underlying warranties that equipment vendors may be willing to provide for specified periods of time for particular equipment and parts. However, it should be noted that the EPC contractor's guarantee of plant completion addresses primarily construction risk, rather than operating risk. The guarantee will likely cover risk up to the point of plant completion and will be satisfied as soon as specific performance tests (e.g., operation at a specified load over a specified period of time) are passed. Moreover, while the underlying equipment warranties covering defects in manufacture may extend over a longer period of time than the plant-completion guarantee, the warranties will likely expire after a relatively limited period of time. Neither the guarantee nor the warranties will likely cover long-term operation of the plant.

In addition, the scope of liability under the guarantee and the warranties is likely to be limited. In particular, the guarantee is likely to be in the form of liquidated damages, and the warranties are likely to be limited to equipment repair or replacement (possibly with an upper limit in the form of liquidated damages). Neither the guarantee nor the warranties are likely to cover fully the replacement energy costs incurred because the plant is not completed or not operating properly.

Risk allocation where utility has power purchase contract with new plant.

If a utility does not attempt to construct and own a new plant but rather has a power purchase contract with a new plant that another company undertakes to construct and own, the allocation of construction and operating risk is affected by the terms of the power purchase contract and the regulatory approach taken by the utility regulatory commission concerning pass-through of the purchased power costs under the contract. Power purchase contracts (e.g., contracts for purchase of electricity from qualifying facilities under the Public Utility Regulatory Policy Act (PURPA), 16 U.S.C. 823a, et. seq.) may require payment for capacity and energy only to the extent the plant actually operates to make capacity and electricity available. In that case, the plant's investors (not the purchasing company's investors or ratepayers) bear the construction and operating risk. However, to the extent that a power purchase contract requires some capacity payment regardless of whether the plant actually is completed and operates, the plant's investors share the construction and operating risk with the purchasing utility. The allocation of the risk borne by the purchasing utility, between the utility's investors and ratepayers, depends on the approach taken by the utility regulatory commission with jurisdiction over the utility's pass-through of purchased power costs. The allocation of such risk is affected by the same factors (other than the factor related to capital structure) that are discussed in Section 7.22 below concerning the allocation of market risk.

7.22. Market risk.

Risk allocation when plant is owned by utility.

When the new electricity generating plant is owned or operated by a company subject to traditional utility regulation, the allocation of market risk depends on the ratemaking process and not on market forces because the regulated company is a monopoly with captive customers. In particular, once the utility regulatory commission has determined the extent to which the investment in plant is included in the company's rate base, the allocation of market risk depends generally on: how the utility regulatory commission uses test period costs to set rates; how the commission sets rate of return; how expeditious the commission is in its rate determinations; and whether the commission allows pass-through of costs (e.g., fuel or purchased power costs) through adjustment clauses.

First, utility regulatory commissions generally require that rates be based on actual test period costs, with some adjustments. As discussed above, utility regulatory commissions have the authority to disallow test period costs found to be insufficiently related to electric service or to be imprudent, and this increases investors' risk that revenues will not cover all costs, with the result that ability to pay interest on debt may be threatened and earned return on equity may be eroded. In addition, utility regulatory commissions may make adjustments of actual test period costs to make costs representative of normal operation for the period or to reflect anticipated future changes in operation. The adjustment of test period costs, particularly for future changes in costs, tends to reduce the investors' risk that revenues will not reflect cost increases and so will erode return on equity. Some utility regulatory commissions take an alternative approach to addressing future changes by allowing use of a forward-looking test period based on projected costs and sales. In addition, during periods of increasing costs, utility regulatory commissions have sometimes included in allowed rate of return an "attrition allowance" in order to offset the potential erosion of earned return in the future. See, e.g., Office of Consumers' Counsel, v. Public Utilities Commission of Ohio, 413 N.E.2d 799, 802-5 (Ohio 1980). The latter approach also tends to reduce investors' market risk.

Second, utility regulatory commissions must determine, for purposes of setting rates, what capital structure, and what capital-cost determination methodologies, to use in setting the utility's return on capital. As discussed above, utility regulatory commissions generally use the utility's actual capital structure in the test period, calculate the actual embedded cost of debt and preferred stock, and use various methodologies to determine the return on common equity. However, some utility regulatory commissions assume -- and determine cost of capital and set the return on capital based on -- a hypothetical "optimal" capital structure for the utility, rather than the utility's actual capital structure.

That approach increases the market risk to investors in that the utility regulatory commission may review both the investment decision itself and the means by which the utility finances the investment. A determination that the utility did not use the optimal capital structure may effectively result in disallowance of a portion of the utility's cost of capital. In addition, utility regulatory commissions generally determine the cost of capital, and set the return on capital, after the investment has been made and put in rate base and retain the right to periodically review and change the return on capital (and, in particular, the return on common equity). This increases the risk to investors that anticipated return may not be realized throughout the life of the investment.

Third, the longer the lag between the time when a rate case is initiated (e.g., when a company requests a rate increase based on test-period cost data) and the time when the utility regulatory commission renders a rate determination and allows new rates to go into effect, the greater the risk borne by investors that revenues will not properly reflect cost changes and that the ability to pay interest on debt and return on equity will be eroded. As discussed above, regulatory lag and resulting risk to investors are reduced to the extent the utility regulatory commission is authorized to allow rates requested by the company to go into effect, subject to refund, before the final rate determination. Obviously, depending on whether costs are generally rising or falling, the delay may actually turn out be advantageous or disadvantageous to investors during a particular period. However, a ratemaking system that tends to result in a relatively close matching of revenues and costs (including return on equity) provides a relatively stable return on equity and tends to reduce investors' risk.

Fourth, in order to mitigate the effect of regulatory lag, many utility regulatory commissions allow the significant, and potentially volatile, costs of fuel to be passed through to ratepayers through adjustment clauses. A fuel adjustment clause establishes a formula under which the fuel-charge portion of the rate is recalculated periodically (e.g., for each upcoming quarter) to reflect recent levels of fuel costs (e.g., fuel costs during the prior quarter) and projected electricity sales. The formula also has a component that takes account of any difference between the dollar amount of fuel costs recovered through the adjustment clause during the prior period (e.g., prior quarter) and that period's actual dollar amount of fuel costs. In that way, over time, the company generally recovers no more, and no less, than its actual fuel costs. This is important because fuel costs may comprise as much as 40 percent of a utility's total cost of service (and, e.g., 20 to 25 percent of the cost of energy from a coal-fired plant). Coordinated to occur with each periodic adjustment (or after several adjustments) are expedited review proceedings conducted by the utility regulatory commission to ensure that only reasonable, properly calculated costs are passed through. By reducing the risk to investors that volatility of fuel costs will erode the return on common equity, use of adjustment clauses puts the risk of fuel-cost volatility on ratepayers.

To the extent purchased power costs (or costs of fuel used to generate purchased power) are passed through an adjustment clause, the risk of volatility of such costs is also put on ratepayers. Similarly, the use by some utility regulatory commission of adjustment clauses for other types of costs of service, or the entire cost or service, puts the risk of cost changes on ratepayers and reduces investors' market risk.

Risk allocation when utility has power purchase contract with new plant.

To the extent that a company purchases electricity from another company rather than constructing electricity generating plant, the allocation of market risk is affected by the terms of the power purchase contract and the approach taken by the utility regulatory commission concerning recovery of costs under the contract. The power purchase contract may set the power purchase price using a formula that recalculates the price periodically to reflect changes in costs (e.g., annual changes in fuel costs). Where the power purchase price is adjustable, market risk is imposed on the purchasing utility, which bears increases in the plant owner's costs; where the power purchase price is fixed, market risk is imposed on the plant owner, who cannot pass through cost increases to the purchasing utility. As between investors and ratepayers of the purchasing utility, the allocation of market risk is affected by the factors (other than the capital-structure-related factor) discussed in this Section 7.22 with regard to a utility that owns a new plant.

8.0. CURRENT ELECTRIC INDUSTRY REGULATORY SYSTEM IN SPECIFIC STATES.

The degree to which the traditional approach (summarized in Section 7.0 above) to regulation of the electric industry applies varies from state to state. Most states have retained a more traditional approach with vertically integrated, monopoly companies providing electricity generation, transmission, and distribution (but with an increased role for merchant generators) and state PUCs setting rates using cost-based ratemaking. This approach exists along side the approach taken by the FERC of promoting competition in wholesale electricity sales. However, some states have started, or are well along in the process of, separating (functionally within a company or structurally among separate companies) electricity generation from transmission and distribution, promoting competition in retail electricity generation and sales, and allowing the competitive market to determine retail sale prices for electricity. Whether or not the separation is by function or structure, electricity distribution continues to be provided, and regulated, as a monopoly service.

Below are discussed the electric industry regulatory systems in several sample states. Five states with significant coal reserves and production (Indiana, Kentucky, New Mexico, Ohio, and Texas) were selected as sample states because states with significant coal reserves and production are more likely to be interested in encouraging local construction of new IGCC plants in order to promote economic development.[162] These five states also provide a spectrum of electric industry regulation, ranging from states following a more traditional approach (Indiana, Kentucky, and New Mexico) to states following a competitive approach (Ohio and Texas).[163]

For Indiana, Kentucky, and New Mexico, the existing regulatory system is described, with particular emphasis on: state PUC jurisdiction and designation of service areas; submission and treatment of rate change requests; determination of test period and cost of service; determination of rate base and treatment of cancelled plant and construction work in progress; use of adjustment clauses; and coal- or other fuel-related provisions. New Mexico's now-repealed retail electric competition provisions are also discussed. For Ohio and Texas, the pre-retail-competition regulatory system is described, focusing on the same matters as for the more traditional states. Then the provisions under retail competition are described, with particular focus on: restructuring through separation of retail electricity generation and sales from transmission and distribution; imposition of

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[162] The states with significant coal reserves and production (defined, for purposes of this paper, as states with estimated recoverable reserves of at least 2,500 million short tons and annual production of at least 15,000 thousand short tons) are, grouped by region: Kentucky, Pennsylvania, and West Virginia; Indiana, Ohio, and Illinois; Texas and Alabama; and New Mexico, Colorado, Montana, North Dakota, Utah, and Wyoming. See http://www.eia.doe.gov/cnea/coal/page/acr/table1.html and http://www.eia.doe.gov/cneaf/coal/page/acr/table15.html.

[163] Of the states with significant coal reserves and production, all except the following have retained a more traditional approach to electric industry regulation: Ohio, Texas, Illinois, and Pennsylvania. See http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

nonbypassable wires charges; and provider-of-last-resort requirements. In addition to the detailed discussion of the regulatory systems in the five states, certain coal-related regulatory provisions for several other states (i.e., Colorado, Illinois, Minnesota, Pennsylvania, and West Virginia) are cited. It should be noted that often the official name of the state PUC in a state discussed below has changed over time; this paper refers to the state PUCs by their most current, official names.

8.1. States with a more traditional electric industry regulatory system.

8.11. Indiana.

Jurisdiction.

Indiana has largely retained a more traditional approach to electric industry regulation. Indiana statute grants the Indiana Utility Regulatory Commission (IURC) jurisdiction over "public utilities," which is defined to include every corporation, partnership, or company that owns, manages, or controls any plant or equipment within the State for "production, transmission, delivery, or furnishing of heat, light, water, or power." Indiana Code (IC) 8-1-2-1(a)(2). For some (but not all) purposes, the definition of "public utility" excludes municipally owned utilities, and the IURC's jurisdiction over municipally owned utilities is not as broad as its jurisdiction over other public utilities. Compare IC 8-1-2-1(a) (defining "public utility" to exclude municipal utilities in connection with rate regulation) and IC 8-1-8.5-1(a) (defining "public utility" to include municipal utilities in connection with power plant construction). Rural electric cooperatives are not excluded from IURC jurisdiction. Further, the IURC may decline to exercise jurisdiction over an "energy utility" or over "retail energy service" of an "energy utility." IC 8-1-2.5-5(a). The IURC has used this authority to decline jurisdiction over merchant plants. See, e.g., Hammond Energy L.L.C., 2002 WL 32091044 (IURC Nov. 26, 2002) (declining jurisdiction over qualifying facility/merchant plant); see also Citizens Action Coalition of Indiana v. Indiana Statewide Association of Rural Electric Cooperatives, 693 N.E.2d 1324 (Ind. Ct. App.1998) (discussing authority under IC 8-1-2.5-5)

Each "electricity supplier" (i.e., each company that "furnishes retail electric service to the public" (IC 8-1-2.3-2(b)) has an "assigned service area." IC 8-1-2.3-3. The assigned service areas cannot be changed, except under limited circumstances involving, e.g., mutual agreement of affected utilities or certain annexations by a municipality with a municipal utility. IC 8-1-2.3-3(h) and 8-1-2.3-6. So long as adequate service is provided, the electricity supplier has the sole right to furnish retail electric service in its assigned service area. IC 8-1-2.3-4(a). See also IC 8-1-2-86(a) (limiting operation of more than one utility in a municipality); and Indiana Gas Co. v. Office of Utility Consumer Counselor, 575 N.E.2d 1044, 1046 (Ind. Ct. App. 1991) (stating that utility regulation "arises out of a 'bargain' struck between the utilities and the state" under which utilities are regulated to ensure provision of the best possible service as "a quid pro quo for being granted a monopoly in a geographical area" for the service).

Ratemaking process: rate changes; test period; rate base; and rate of return.

Under Indiana statute, a public utility's rates must be "reasonable and just" (IC 8-1-2-4), and "unnecessary or excessive" costs cannot be considered in setting such rates (IC 8-1-2-48(a)). The rates must be reflected in rate schedules filed with the IURC (IC 8-1-2-38), and no changes may be made to the rate schedules unless the public utility provides 30 days' notice to the IURC (or such shorter notice as the IURC allows) and the IURC approves the changes (IC 8-1-2-42(a)). A public utility cannot file a request for a general rate increase within 15 months of its prior general rate increase request. Id. However, the IURC may order a "more timely increase" if the increase is for a different type of service, if the "utility's financial integrity or service reliability is threatened" (IC 8-1-2-42(a)(2)) or if the increase is based on a "rate structure previously approved" or on orders of federal courts or regulatory agencies (IC 8-1-2-42(a)(3)).

The IURC must generally review public utilities' "basic rates and charges" at least every 4 years. IC 8-1-2-42.5. If the IURC finds that any rates are unjust or unreasonable, the IURC must determine just and reasonable rates to be charged in the future. IC 8-1-2-68.

The IURC has some flexibility in setting rates in that it may approve rates based on "market or average prices, price caps, index based prices," or performance based prices. IC 8-1-2.5-6(a)(2). However, the IURC has followed a more traditional approach of cost-based ratemaking.

In particular, the IURC generally uses the following approach to set rates. The IURC's primary objective in a rate case is to establish rates that are "sufficient to permit the utility to meet its operating expenses plus a return on investment which will compensate its investors." L.S. Ayers & Co. v. Indianapolis Power & Light Co., 351 N.E.2d 814, 819 (Ind. Ct. App. 1976) (citing FPC v. Hope). This usually involves an initial determination of the utility's future revenue requirement based on the operating results of a test year, which is generally the most recent year for which complete data are available.

The IURC may adjust the test year results in order to disallow excessive or imprudent expenditures or to correct for any unrepresentative operating results. Id. at 819-20; see also City of Evansville v. Southern Indiana Gas and Electric Co., 339 N.E.2d 562, 569-71 (Ind. Ct. App. 1975) (stating that IURC has discretion to disallow costs and adjust test period costs to make them representative of normal operation in the test period and of future operation); and Indiana Gas, 675 N.E.2d at 745 (stating that rates can not be based on "hypothetical" expenses). The IURC may also disallow expenditures that are not sufficiently related to the provision of utility service. Indiana Gas, 675 N.E. at 744 (holding that operating costs must have a "connection" to utility service and upholding disallowance of costs of cleanup of hazardous wastes produced before utility ownership of sites because connection of costs to utility service was "too tenuous").

In addition, the IURC must determine the "fair value" of a public utility's property that is "actually used and useful for the convenience of the public." IC 8-1-2-6. Used and useful property is property "actually devoted to" and "reasonabl[y] necessary to" providing utility service. Citizens Action Coalition of Indiana Inc. v. Northern Indiana Public Service Co., 472 N.E.2d 938, 941 (Ind. Ct. App. 1984), aff'd, 485 N.E.2d 610 (Ind. 1985), cert. den., 476 U.S. 1137 (1986). In making the "fair value" determination, the IURC must consider both the original cost and the reproduction cost of the property (e.g., an electricity generating plant) and must balance this evidence along with other relevant factors to reach a figure that is "fair and equitable to both investor and consumer." Capital Improvement Board of Managers of Marion County v. Public Service Commission of Indiana, 375 N.E.2d 616, 631 (Ind. Ct. App. 1978); see also Indianapolis Water Co. v. Public Service Commission of Indiana, 484 N.E.2d 635, 638-40 (Ind. Ct. App. 1985) (holding that IURC cannot ignore "inflation" in determining "fair value" of property). Since utility property must be used and useful to be included in rate base, return on capital during construction accrues as AFUDC and is added to rate base when the plant goes into service. However, the IURC considers on a case-by-case basis the financial consequences of such an approach and may allow AFUDC to continue to accrue until new rates that include the plant costs go into effect. See, e.g., Northern Indiana Public Service Co., 71 PUR4th 462, 464-65 (IURC Nov. 27, 1985).

Except as modified by certain statutory provisions adopted in the 1980s in response to nuclear plant cancellations (and discussed below), the fair value of used and useful utility property is the rate base for which the IURC must set a rate of return, which must meet the requirements in Bluefield Water Works & Improvement. L.S. Ayers, 351 N.E.2d at 821. The company's return on capital is determined by considering the amount and cost of each component (debt, preferred stock, and common stock) of the company's capital structure. City of Evansville, 339 N.E.2d at 569-70. In setting rate of return the IURC may consider various factors including "the ability to attract new capital, a comparison with return in other industries, production efficiency, and credit ratings." Office of Utility Consumer Counselor v. Public Service Co. of Indiana, 449 N.E.2d 604, 609 (Ind. Ct. App. 1983). However, the IURC must set a rate of return based on the "impact of known circumstances," and not on "speculation" concerning, e.g., the impact of possible legislation not yet enacted. Citizens Action Coalition of Indiana v. Public Service Co. of Indiana, 612 N.E.2d 199, 201 (Ind. Ct. App. 1993).

The above-described ratemaking approach was applied to several nuclear plants in Indiana whose construction was commenced but which were cancelled in the 1980s prior to completion. The IURC's reviews of the cancelled plants, like the review of completed plants, were conducted after the fact, i.e., after construction was completed or terminated.

For example, a public utility began construction of a nuclear plant in 1970 but cancelled the project in 1981 due to litigation, opposition to licensing, and escalating costs. Determining that the decision to build the plant was prudent when construction began, the IURC allowed the utility to amortize, and thereby recover in its rates, about $191 million out of a total of about $206 million invested in the project. No return on the capital was allowed. On review, the Indiana Supreme Court reversed the IURC's decision on the ground that the cancelled plant was not used and useful. Citizens Action Coalition of Indiana, 485 N.E.2d at 614. As the Court explained, the ratepayers cannot be required to "replenish lost capital which had never become 'used and useful' property or, in other words be required to act..., as insurer of the investor's risk, unless the consumers received an interest in return which provided an opportunity to earn a return on the capital supplied." Id. at 615. The Court distinguished between plant that was used and useful and so could be amortized after retirement and plant that never became used and useful and so could not be amortized. Subsequently, the Court clarified that even "planning, analysis, and investigation expenses" associated with the cancelled plant were not recoverable. Northern Indiana Public Service Co. v. Citizens Action Coalition of Indiana, 548 N.E.2d 153, 156 (Ind. 1989). See also National Rural Utilities Cooperative Finance Corp. v. Public Service Commission of Indiana, 528 N.E.2d 95, 103 (Ind. Ct. App. 1988), aff'd, 552 N.E.2d 23 (Ind. 1990) (upholding denial of recovery of costs of cancelled nuclear plant as not "used and useful," even though owner was insolvent).

In light of the Court's 1985 Citizens Action Coalition of Indiana decision, the IURC took a different approach concerning recovery of costs incurred by another public utility for another cancelled nuclear plant. That public utility began construction of a nuclear plant but cancelled the project in light of construction delays, cost escalations, and a task force report recommending cancellation. Consistent with Citizens Action Coalition of Indiana, the IURC did not allow recover of the costs of the cancelled plant. However, in setting the utility's rates, the IURC added a risk premium to the rate of return on the utility's rate base (which did not include the nuclear plant costs). Upon review of the IURC's decision, the Court upheld the approval of a risk premium to reflect the utility's increased risks of lack of access to capital markets, cash flow deficiency, inflated equity cost, and insolvency as a result of the writing off of the utility's investment in the cancelled nuclear plant. Citizens Action Coalition of Indiana Inc. v. Public Service Co. of Indiana, 552 N.E.2d 834, 838 (Ind. Ct. App. 1990).

The IURC took further action concerning recovery of the utility's cancelled plant investment. The IURC allowed the utility to recover, as an amortized "regulatory asset," $475 million of federal income tax savings that would be realized from deducting the utility's net loss due to the plant cancellation from the utility's net income. The Court had previously held that such tax savings should be retained by the utility. Id. at 839-40. Although the federal income tax rate was subsequently reduced, the IURC did not reduce the utility's rates to reflect the lower tax benefit. The Court reversed the IURC on the ground that the failure to reduce rates to reflect the reduced tax benefit had an effect analogous to amortizing the cancelled plant, an approach that had been previously rejected. Citizens Action Coalition of Indiana Inc. v. Public Service Co. of Indiana, 582 N.E.2d 330, 336 (Ind. 1990).

After the decisions denying recovery of costs of cancelled nuclear plants, Indiana adopted statutory provisions to allow for recovery of cancelled plant under certain circumstances. Under these provisions, proposed construction of new facilities by a public utility (including a municipal utility) must be approved upfront by the IURC. In particular, the IURC must develop and keep current an analysis of the long-range needs for expansion of facilities for electricity generation in the state. IC 8-1-8.5-3(a). A public utility must not construct, purchase, or lease any "facility for the generation of electricity" (e.g., a new IGCC plant) for use in furnishing public utility service without first obtaining a certificate of public convenience and necessity from the IURC. IC 8-1-8.5-2. In order to obtain such a certificate, the utility must file an estimate of the construction, purchase, or lease cost of the proposed facility. IC 8-1-8.5-5(a). In approving the certificate, the IURC must make a finding on the best estimate of the facility's costs. In addition, the IURC must make findings that, inter alia, the facility is required by the public convenience and necessity and is consistent with the IURC's analysis of long-range needs and with any approved utility-specific proposal as to future needs for serving the state or the utility's service area. IC 8-1-8.5-5(b)(2).

Moreover, the certificate of public convenience and necessity is subject to future review by the IURC. The certificate must be reviewed if the IURC's estimate of future growth in electricity use changes and must be modified or revoked if completion of the facility is no longer in the public interest. IC 8-1-8.5-5.5. In general, absent fraud, concealment, or gross mismanagement, a utility "shall recover" through its rates the actual costs (including capital investment and return on capital) that the utility incurs in reliance on the certificate of public convenience and necessity for the facility. IC 8-1-8.5-6.5. Cost recovery begins once the facility is completed and used and useful or, to the extent allowed, after the facility is cancelled and construction is terminated.

Further, after issuance of the certificate, as construction of the facility proceeds, the IURC must conduct, if requested by the utility, an ongoing review of the construction and the costs and may modify or revoke the certificate if the construction or costs are disapproved. However, utility has the option of electing to have the IURC instead conduct review of construction and costs only subsequent to completion or cancellation of the facility. IC 8-1-8.5-6. The advantage of ongoing review by the IURC is that construction costs approved in the ongoing review (and return on those costs) must be included in the utility's rates without further IURC review. This includes both cases where the facility is completed (IC 8-1-8.5-6.5(1)) and cases where the facility is cancelled due to modification or revocation of the certificate as a result of a change in the IURC's future electricity demand estimates or of the IURC's disapproval of other construction costs in the ongoing review (IC 8-1-8.5-6.5(3)). Another advantage is that the determination that imposes costs on ratepayers is made earlier (i.e., after each ongoing review proceeding), although the actual pass-through of approved costs does not begin until the facility is completed or cancelled. In contrast, if only subsequent review is conducted by the IURC, then construction costs of completed or cancelled plant (and return on those costs) within the certificate amount are included in the utility's rates unless they result from "inadequate quality control" and costs in excess of the certificate amount are included in rates only if the construction is shown to be "necessary and prudent." IC 8-1-8.5-6.5(2) and (4). Also the determination imposing costs on ratepayers is not made until the after-the-fact-review is conducted. While utilities have requested, and the IURC has approved, certificates for new electricity generating plant, none of these plants have been cancelled and so the provisions concerning recovery of costs of cancelled plant have not as yet been applied.

Indiana adopted similar statutory provisions concerning approval of, and cost recovery for, capital projects associated with compliance requirements for the Acid Rain Program under the Clean Air Act. A utility has the option of submitting an environmental compliance plan (IC 8-1-27-6), which includes the costs of developing and implementing the plan and is reviewed by the IURC (IC 8-1-27-8). In the absence of "fraud, concealment, gross mismanagement, or inadequate quality control" (IC 8-1-27-12(a)), the utility may include in rate base the costs of completed projects consistent with the approved plan if the projects are "used and useful" (IC 8-1-27-12(c)). To the extent such costs exceed the amount in the approved plan, the costs may be recovered if they are "necessary and prudent." IC 8-1-27-12(b). These criteria for recovery also apply, if the plan is modified by the IURC, to costs under the plan that were incurred before such modification. IC 8-1-26-16. If the utility cancels a project due to the IURC's withdrawal of approval of inclusion in the plan, the utility may recover previously incurred costs and associated return (absent fraud, concealment, gross mismanagement, or inadequate quality control) that were previously approved or, for costs in excess of the previously approved plan, that are necessary and prudent. IC 8-1-27-17. The IURC must conduct an ongoing review, if requested by the utility, of the capital project, and recovery of costs approved in such a review cannot be challenged if the project is "used and useful." IC 8-1-27-19.

Adjustment clauses.

Rates may include a fuel adjustment clause. City of Evansville, 339 N.E.2d at 591-95; see also IC 8-1-2-42(b) (stating that no changes in rates "based on costs" are "effective without the approval" of the IURC) and 8-1-2-42(d) (allowing changes in the fuel charge no more frequently than every three months). The fuel cost charge may be based on the cost of fuel used by the public utility to generate electricity or the cost of fuel included in a utility's purchased power costs. The IURC will approve a requested fuel cost charge if, inter alia: the utility made "every reasonable effort to acquire fuel and generate or purchase power or both" in order to provide electricity "at the lowest fuel cost reasonably possible" (IC 8-1-2-42(d)(1)); increased fuel costs are not offset by other decreased operating costs; and the charge will not result in a return exceeding the utility's allowed return. IC 8-1-2-42(d). The utility must also provide reasonable estimates of future, average fuel costs. Before approving any rate change based on cost of fuel, the IURC must examine the utility's books and records and hold "a summary hearing on the sole issue of the fuel charge." IC 8-1-2-42(b). The IURC's consumer counselor must review and report to the IURC on any proposed fuel cost charge within 20 days after the request is filed, and the IURC must hold the summary hearing within 20 days after receipt of such report. Id.

Similarly, rates may include other adjustment clauses determined by the IURC to be appropriate. IC 8-1-2-42(a) distinguishes between, and authorizes the IURC to allow, "a general increase in basic rates and charges" (e.g., a rate increase in a general rate case) and "changes in rates related solely to the cost of fuel or to the cost of purchased gas or purchased electricity or adjustments in accordance with tracking provisions approved by" the IURC. In accordance with these provisions, the IURC has approved the inclusion of purchased power demand costs in adjustment clauses because the costs are potentially volatile. See, e.g., PSI Energy, Inc., 210 PUR4th 299, 2001 WL 797974 (IURC May 16, 2001); and PSI Energy Inc. v. Indiana Office of Utility Consumer Counsel, 764 N.E.2d 772 (Ind. Ct. App. 2002), transfer den., 783 N.E.2d 698 (Ind. 2002). The IURC has also allowed inclusion of payments by the owner of the combined cycle portion of an IGCC plant for coal gasification services provided by the owner of the coal gasification portion of the plant because of uncertainty as to the level of payments over time. PSI Energy, Inc., 173 PUR4th 393, 456-58, 1996 WL 767535 (IURC Sept. 27, 1996).

Special provisions for clean coal technology.

Over several years, Indiana has adopted an array of special provisions aimed at encouraging "clean coal technology." The earliest provision, IC 8-1-2-6.6 (initially adopted in 1985), addresses inclusion in rates of certain construction costs associated with "clean coal technology," which is defined as including technology that "directly or indirectly" reduces sulfur or nitrogen based emissions associated with combustion or use of coal and that is "not in general commercial use at the same or greater scale" in the U.S. as of January 1, 1989. IC 8-1-2-6.6(a) (definition of "clean coal technology"). A utility may include in rate base, as construction work in progress or CWIP, the value of air pollution control property where construction began after October 1985 and is ongoing and where the property constitutes clean coal technology approved by the IURC and is designed to "accommodate" burning of Illinois Basin coal. IC 8-1-2-6.6(a) (definition of "qualified pollution control property"). The facility must burn "only Indiana coal as its primary fuel source" (IC 8-1-2-6.6(b)(1)) or show justification for burning "some non-Indiana coal" (IC 8-1-2-6.6(b)(2)).

This provision (along with similar provisions in IC 8-1-27-1, et seq., discussed above) was successfully challenged as contrary to the commerce clause of the U.S. Constitution because of its limitation to controls on facilities designed for and burning Indiana coal. General Motors Corp. v. Indianapolis Power & Light Co., 654 N.E.2d 752, 763-67 (Ind. Ct. App. 1995). A similar provision was adopted (in 1990) that allows rate base treatment of CWIP for air pollution control property whose construction began after March 2002 and is ongoing, but the provision is not limited to facilities designed for and burning Indiana coal. The provision defines, as clean coal technology, technology that reduces mercury (as well as technology that reduces sulfur or nitrogen emissions) and that was not in general commercial use on November 15, 1990. IC 8-1-2-6.8.

Under either IC 8-1-2-6.6 or 8-1-2-6.8, the utility may request rate base treatment to the extent that the qualified air pollution control property has been under construction for at least six months. 170 Indiana Administrative Code (IAC) 4-6-9. The inclusion of a portion of the value of air pollution control property under construction in rate base, for purposes of a general rate case, means that the utility's rates may recover the return on capital associated with that portion of utility's investment in such property. The IURC must approve the use of air pollution control property if, inter alia, the costs are reasonable. Approval is deemed granted if the property is covered by a certification under IC 8-1-8.5-1, et seq. , a certification under analogous provisions (discussed below) in IC 8-1-8.7-1, et seq., or a utility's approved environmental compliance plan under the Clean Air Act under IC 8-1-27-1, et seq. 170 IAC 4-6-4. The IURC must give rate base treatment, during construction, to approved air pollution control property and may do so in a general rate proceeding, in a certification proceeding under IC 8-1-8.5-1, et seq. or IC 8-1-8.7-1, et seq. , or in an environmental-compliance-plan review proceeding under IC 8-1-27-1, et seq. 170 IAC 4-6-11. Rate treatment of air pollution control property when construction is cancelled or indefinitely suspended is governed by the appropriate provisions under IC 8-1-8.5-1, et seq., 8-1-8.7-1, et seq., or 8-1-27-1, et seq.. 170 IAC 4-6-23. After its initial request for rate base treatment of air pollution control property, the utility may request such treatment for additional amounts of such property in six-month intervals. 170 IAC 4-6-18. Assuming that the IURC's handling of such requests takes about four months, this means that a utility may recover, on an ongoing basis, the return on capital for each six-month portion of investment in air pollution control equipment about four to ten months after making that portion of the investment. During the lag period between making the investment and including the return on capital for the investment in the rates, the utility treats the return on capital as allowance for funds during construction (AFUDC). The AFUDC is subsequently treated as part of the value of the investment and is eventually added to rate base, consistent with the appropriate provisions under IC 8-1-8.5-1, et seq., 8-1-8.7-1, et seq., or 8-1-27-1, et seq..

The IURC has applied IC 8-1-6.6 and 8-1-6.8 to projects involving construction of nitrogen oxides emission controls (e.g., selective catalytic reduction control equipment and combustion modifications such as low NOx burners) undertaken by some utilities. See, e.g., PSI Energy, Inc., 2001 WL 401306 at 6 (IURC Feb. 14, 2001). Moreover, in several cases, the IURC held that it has the authority to allow a utility to recover -- through an adjustment clause, rather than in a rate case -- the return on capital for CWIP in such projects during ongoing emission control installation. The IURC stated that it was adopting this approach because: the investment in the projects was substantial; it would be difficult to coordinate initiation of rate cases with investments in ongoing construction; and the inability to recover return on capital on an ongoing basis would have a significant, adverse impact on the companies involved. See, e.g., Northern Indiana Public Service Co., 2002 WL 32089927 at 9 (IURC Nov. 26, 2002), aff'd, Citizens Action Coalition v. Northern Indiana Public Service Co., 804 N.E.2d 289 (Ind. Ct. App. 2004); and Indianapolis Power & Light Co., 2002 WL 32091040 at 8 (IURC Nov. 14, 2002).

Although the operative terms in IC 8-1-6.6 and 8-1-6.8, "air pollution control property" and "clean coal technology," have been applied to emission controls, it can be argued that the terms are broad enough to include an entire IGCC plant, which integrates coal gasification, synthesis gas cleaning, combined cycle, and emission control technologies to achieve clean use -- with, e.g., reduced sulfur dioxide, nitrogen oxide, and mercury emissions -- of coal to generate electricity. However, it seems more likely that only certain elements (e.g., gasification and synthesis gas cleaning) of the plant will be treated as property subject to these provisions and that other elements (e.g., coal handling equipment and the combined cycle combustion and steam turbines) will not be included in such property.[164]

Indiana statute also includes other special provisions -- similar to the electricity-generating-plant certification provisions under IC 8-1-8.5-2 through 8-1-8.5-6.5 -- concerning approval of, and recovery of costs (including return of and on capital) associated with, clean coal technology. Under IC 8-1-8.7-3(a), a public utility (including a municipal utility) must apply for and obtain a certificate of public convenience and necessity before using clean coal technology at an electricity generating facility. The IURC must issue a certificate if the project offers "substantial potential of reducing sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989." IC 8-1-8.7-3(b). In issuing a certificate, the IURC must make findings on the estimated project costs and on the expected "dispatching priority" for the project (IC 8-1-8.7-3(b)(8)), as well as findings that the public convenience and necessity will be served and that the project will use Indiana coal as the primary fuel or is justified in using non-Indiana coal. IC 8-1-8.7-4(b)(3). The IURC may modify or revoke the certificate in light of changes in the estimate of cost of, or need for,

[164] Indiana statute includes two other provisions (IC 8-1-2-6.1 and 8-1-2-6.7) affecting the timing of recovery of investment in clean coal technology. The IURC is required to allow recovery, "as operating expenses" (IC 8-1-2-6.1(c)), of "preconstruction costs (including design and engineering costs) associated with employing clean coal technology" that is certificated if the project uses and will continue to use Indiana coal as the primary fuel or is justified in using non-Indiana coal (IC 8-1-2-6.1(c)(2)). A utility may seek treatment of such costs as operating costs in a general rate case. 170 IAC 4-6-16. The provision allows these preconstruction costs to be recovered on a more timely basis than would treating them as capital expenditures to be amortized, e.g., over the useful life of the project. Under IC 8-1-2-6.7, clean coal technology is allowed a depreciation period, for rate making purposes, of not less than the lesser of 10 years or the property's useful economic life and not more than 20 years if the facility uses Indiana coal or shows justification for using non-Indiana coal. The provision in effect allows accelerated depreciation of such property. For example, clean coal technology with a useful life between 10 and 20 years may be depreciated over a period that may be as short as 10 years, while such technology with a useful life exceeding 20 years may be depreciated over a period ranging from 10 to 20 years.

clean coal technology. IC 8-1-8.7-5. If the project is cancelled due to modification or revocation of the certificate, the utility may recover its "investment in the technology, along with a reasonable return on the unamortized balance." IC 8-1-8.7-6. However, costs in excess of the approved costs in the certificate may be recovered only if there is a showing that the excess costs were "necessary and prudent" and there was no "fraud, concealment, or gross mismanagement" by the utility. Id.

After certification of the clean coal technology, the IURC must conduct, if requested by the utility, an ongoing review of the construction and costs of the project as construction progresses. IC 8-1-8.7-7(b). The IURC has issued such certificates with ongoing review (under IC 8-1-8.7-7(b)) for nitrogen oxides control equipment, allowed recovery (under IC 8-1-2-6.6) of the return on capital for additional CWIP on such equipment at six-month intervals, and coordinated the ongoing review proceedings with the six-month updates for recovery of return on capital for CWIP. See e.g., Southern Indiana Gas and Electric Co., 2001 WL 1708778 at 14-15 (IURC Aug. 29, 2001) and PSI Energy, Inc., 2003 WL 21004706 (IURC Jan. 29, 2003). Upon approval of construction and costs in the ongoing review, the inclusion in the rate base of that part of the clean coal technology cannot be challenged "on the basis of excessive cost, inadequate quality control, or inability to employ the technology." IC 8-1-8.7-7(c). If construction and costs are disapproved in the ongoing review, the IURC may modify or revoke the certificate. If, as a result, the project is cancelled, the public utility can recover its previously approved investment plus a reasonable return, absent fraud, concealment, or gross mismanagement. IC 8-1-8.7-7(d). The utility has the option of having the IURC review construction and costs only after completion of the project. However, costs exceeding the costs in the certificate may be included in rate base only if shown to be "necessary and prudent," while costs within the certificate amount can be challenged "only on the basis of inadequate quality controls." IC 8-1-8.7-8.

Upon completion of the project, the utility may dispatch it in accordance with the dispatch priority set forth in the certificate, and such dispatching "shall not be considered to be in conflict with" the requirements for recovery of costs through a fuel adjustment clause (under IC 8-1-2-42). IC 8-1-8.7-9. Presumably this means that such dispatching may not be used as a basis for challenging recovery of fuel costs on the ground that the utility failed to make "every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible." IC 8-1-2-42(d)(1).

As noted above, the provisions for certification and cost recovery for clean cost technology (IC 8-1-8.7-3 through 8-1-8.7-9) are similar to the general certification and cost recovery provisions (IC 8-1-8.5-2 through 8-1-8.5-6.5) applicable to all new electricity generating facilities. For electricity generating facilities that will use clean coal technology, both sets of provisions apply. IC 8-1-8.7-10. For example, the Wabash gasification facility was certificated under both IC 8-1-8.5-1, et seq. and 8-1-8.7-1, et seq.. PSI Energy, Inc., 143 PUR4th 521, 542, 1993 WL 328722 (IURC May 26, 1993).

Apparently, no facilities certificated under IC 8-1-8.5-1, et seq. or IC 8-1-8.7-1, et seq. have been terminated and so the provisions concerning recovery of costs for cancelled plant have not yet been applied.

Finally, under two relatively new Indiana statutory provisions, IC 8-1-8.8-11 and 8-1-8.8-12, the IURC has broad, additional authority. Specifically, the IURC must encourage "clean coal and energy projects" by providing certain financial incentives if the projects are "reasonable and necessary."[165] IC 8-1-8.8-11(a). "Clean coal and energy projects" include: new energy generating facilities using clean coal technology, or advanced emission reduction technology for existing energy generating facilities, that are fueled primarily by coal or gas derived from coal from the Illinois Basin; projects for transmission to serve new energy generating facilities; projects using alternative energy sources such as renewables; and the purchase of fuels produced by a coal gasification facility in Indiana. IC 8-1-8.8-2. "Clean coal technology" under this provision includes technology that "directly or indirectly" reduces emissions "associated with the combustion or use of coal" and not in general commercial use at the same or greater scale in the U.S. as of November 15, 1990. IC 8-1-8.8-3(1) and (2). "New energy generating facilities" include new construction, repowering, or capacity expansion begun after July 1, 2002 that is "dedicated primarily to serving Indiana retail customers." IC 8-1-8.8-8(2)(B). The types of financial incentives that the IURC must provide include: timely recovery of construction and operating costs; authorization of up to three additional percentage points on return on equity; incentives (e.g., timely cost recovery and additional return on equity) for purchase of fuels produced by a coal gasification facility in Indiana; and incentives for development of alternative energy sources. IC 8-1-8.8-11(a). If a utility applies for financial incentives under this provision, the IURC must make a determination of eligibility for such incentives within 120 days, unless the utility does not cooperate fully in the proceeding. IC 8-1-8.8-11(d).

The IURC is also required to provide financial incentives for "new energy generating facilities" in the form of "timely recovery" (e.g., through a retail rate adjustment mechanism) of "costs incurred in connection with the construction, repowering, expansion, operation, or maintenance of the facilities." IC 8-1-8.8-12(a). Specifically, the IURC must allow recovery of costs associated with qualified utility system property if "the expected costs...and the schedule for incurring those costs are reasonable and necessary." IC 8-1-8.8-12(d). Similarly, the IURC must allow recovery of costs associated with purchase of fuel produced by a coal gasification facility if the costs are

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[165] West Virginia, another coal state using more traditional utility regulation, has a similar provision requiring the West Virginia Public Service Commission (WVPSC) to "authorize rate-making allowances for electric utility investment in clean coal technology facilities or electric utility purchases of power from clean coal technology facilities located in West Virginia" in order to encourage such investment. West Virginia Code (WVC) 24-2-1g(b). Apparently, the provision has not been used. However, West Virginia statute includes a similar provision for investment in alternative fuels. Under the latter provision, the WVPSC has approved "accelerated rate recovery of [natural gas vehicle] investments" (including cost of capital) by gas utilities through a rate surcharge on most customers. Hope Gas, Inc., 160 PUR4th 512, 515, 1995 WL 310052 (WVPSC 1995).

“reasonable and necessary.” IC 8-1-8.8-12(e). The term “timely recovery” in IC 8-1-8.8-12(a), as well as in IC 8-1-8.8-11(a), seems to encompass, inter alia, inclusion of construction work in progress in the rate base in order to allow for ongoing recovery of cost of capital for such construction and recovery of these and other costs through an adjustment clause (rather than through a rate case).

The IURC has coordinated its application of IC 8-1-8.7-3 through 8-1-8.7-9 and IC 8-1-8.8-11 and 8-1-8.8-12 in cases involving nitrogen oxides emission controls undertaken by some utilities. As discussed above, the IURC issued certificates of public convenience and necessity for the emission control projects and agreed to conduct ongoing review during construction. Further, the IURC approved not only adjustment-clause recovery of the return on capital during construction of such projects, but also adjustment-clause recovery of depreciation and operation and maintenance costs for the projects once the emission control projects go into service. See, e.g., Southern Indiana Gas and Electric Co., 2003 WL 21048981 at 4-5 (IURC Jan 2, 2003); Northern Indiana Public Service, 2002 WL 32089927 at 4-9; and Indianapolis Power & Light, 2002 WL 32091040 at 3-8. This approach ensures a dedicated stream of revenues covering all costs -- starting with return on capital on construction work in progress and continuing with return of and on capital and operating costs -- of the emission control projects.[166]

It seems that Indiana statute authorizes the IURC to adopt the same approach for new IGCC plants under the 3Party Covenant. Such a plant clearly seems to qualify as a new electricity generating facility and as clean coal technology eligible for certification and ongoing review under IC 8-1-8.5-2 through 8-1-8.5-6.5 and IC 8-1-8.7-3 through 8-1-8.7-9. In addition, such a plant clearly seems to qualify for: inclusion of construction work in progress in rate base; and for adjustment-clause recovery of return on capital during construction and of capital investment, return on capital and operating costs after commencement of plant service, under IC 8-1-2-6.8, 8-1-8.8-11, and 8-1-8.8-12. (The provision in IC 8-1-8.8-2 that Illinois Basin coal must be used for generation facilities under IC 8-1-8.8-11 is likely to be interpreted as unlawful and inapplicable. See General Motors, 654 N.E.2d at 763-67.) This approach will provide an assured revenue stream for full cost recovery for IGCC plants, consistent with the 3Party Covenant. See Sections 8.3, 9.3, and 9.4 below.

[166] Minnesota, another state using more traditional utility regulation, takes a different approach to encouragement of clean coal technology by entitling an “innovative energy project” (e.g., an IGCC plant proposed for the taconite region of the state) to enter into a long-term power purchase contract with a major utility in the state, with the terms subject to Minnesota Public Utilities Commission (MPUC) review. Minnesota Statutes (MS) 216B.1694(2)(a)(7). See also MS 216B.1694((2)(a)(8) (making project eligible for renewable development grant); and MS 216B.1693(a) and (c) (requiring utility to purchase at least 2 percent of its power supply for retail customers from “clean energy technology” found by the MPUC to be “a least-cost resource” (including the “innovative energy project” unless found to be contrary to the public interest)).

8.12. Kentucky.

Jurisdiction.

Kentucky has largely retained a more traditional approach to electric industry regulation. Kentucky statute provides the Kentucky Public Service Commission (KPSC) with authority to regulate any "utility", i.e., any person (except a municipality) that owns, controls or operates or manages a facility used or to be used for "generation, production, transmission, or distribution of electricity to or for the public, for compensation, for lights, heat, power, or other uses." Kentucky Revised Statutes Annotated (KRSA) 278.010(3)(a). Rural electric cooperatives are not excluded from the KPSC's jurisdiction.

In light of the Kentucky legislature's express determination that it is in the public interest to divide the state into geographic areas with one retail electric supplier for each certified territory (KRSA 278.016), the KPSC is required to set boundaries of the certified territory for each retail electric supplier based on the service areas as of 1972 (KRSA 278.017). Each retail electric supplier has an "exclusive right to furnish retail electric service to all electric consuming facilities" in its certified territory and must not provide service to customers in the certified territory of another retail electric supplier. However, if a supplier fails to provide adequate service to an electric consuming facility, the KPSC may authorize another supplier to provide the service. KRSA 278.018(1).

Further, no person may begin providing utility service "to or for the public" or begin construction of any plant for furnishing utility service without a certificate of public convenience and necessity. KRSA 278.020(1). There is an exception from this requirement for a retail electric supplier for "service connections to electric-consuming facilities" in its certified territory and for "ordinary extension of an existing system in the usual course of business." Id. A determination of public convenience and necessity requires findings of a need for a new facility to meet service requirements and an absence of wasteful duplication and multiplicity of physical properties. In considering an application for a certificate "to construct a base load electric generating facility," the KPSC may "consider the policy of the General Assembly to foster and encourage use of Kentucky coal by electric utilities" serving Kentucky. Id. See Kentucky Utilities Co. v. Public Service Commission of Kentucky, 252 S.W.2d 885, 890 (Ky. App. 1952) and Kentucky Utilities Co. v. Public Service Commission Kentucky, 390 S.W.2d 168 (Ky. App. 1965) (concerning findings necessary for issuance of certificate). A certificate must be exercised within one year in order to remain valid.

Ratemaking process: rate changes; test period; rate base; and rate of return.

A utility must charge "fair, just and reasonable rates" for services (KRSA 278.030(1)), and the rates must be set forth in filed rate schedules (KRSA 278.160). See Stephens v. South Central Bell Telephone Co., 545 S.W.2d 927, 931 (Ky. 1976) (citing FPC v. Hope in explaining that rates must be just and reasonable). Rates cannot generally be changed by the utility without 30 days notice, but the KPSC may shorten the notice period to 20 days for good cause. KRSA 278.180(1). The KPSC may suspend the effectiveness of the new rates for up to five months from the proposed effective date for the rates if the rates are based on costs from a historical test period and up to six months if the rates are based on projected costs from a forward-looking test period. If the KPSC does not complete its proceeding and issue a decision by the end of five or six months (whichever is applicable), the utility may begin charging the new rates, subject to refund. However, if the KPSC determines that, because of the failure to allow the rates to become effective before the end of the suspension period, the "company's credit or operations will be materially impaired or damaged," then the KPSC may let the rates become effective sooner. KRSA 278.190(2). The KPSC must issue a decision on a proposed rate increase within 10 months of the filing of the proposed increase. KRSA 278.190(3).

The KPSC may investigate any rate upon complaint that the rate is "unreasonable or unjustly discriminatory" or on the KPSC's own motion. KRSA 278.260. If the KPSC finds a rate in unjust or unreasonable, the KPSC must prescribe a just and reasonable rate for the future. KRSA 278.270.

Kentucky statute sets forth basic procedures for setting just and reasonable rates. Rates may be based on costs from a historical test period or a forward-looking test period. For proposed general rate increases, the KPSC must allow a utility to use a historical test period of 12 calendar months before the proposed rate filing or a forward-looking test period of 12 calendar months after the maximum suspension period. KRSA 278.192(1). The historical test period data may be adjusted for "known and measurable changes." 807 Kentucky Administrative Regulations Service (KAR) 5:001 §10(1)(a). A rate filing using a forward-looking period must provide data on nine months before the filing, including at least six months of actual data. KRSA 278.192(2). The KPSC generally bases rates on a historical, rather than a forward-looking, test period. <u>But see</u> <u>Kentucky-American Water Co.</u>, 1993 WL 595984 at 18 (KPSC Nov. 19, 1993) (stating that use of a forward-looking test period tend "to decrease the risk that...[a utility] will not earn its allowed return" and taking this into account in setting return on equity).

Further, the KPSC may "ascertain and fix the value of the whole or any part of the property of any utility in so far as the value is material to the exercise of the jurisdiction of the commission." KRSA 278.290(1). The KPSC may make "revaluations from time to time and ascertain the value of all new construction, extension and additions to the property." <u>Id.</u> It is not clear, from the face of the provision, whether revaluations can apply in cases other than new construction, extension, or addition, e.g., to unchanged, existing property. In fixing the value of property, the KPSC must "give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for ratemaking purposes." <u>Id.</u> On its face, KRSA 278.290(1) does not limit determinations of rate base to facilities that are used and useful.

On the contrary, the provision has been held to be "broad enough" to allow the KPSC to consider additional factors in the case of a rural electric cooperative with a new coal-fired plant producing more electricity than needed at that time to meet the cooperative's customer load. National-Southwire Aluminum Co. v. Big Rivers Electric Cooperative, 785 S.W.2d 503, 512 (Ky. App. 1990). Although in previous cases the KPSC had limited rate base to facilities that were "used and useful" (see, e.g., Fern Lake Co. v. Public Service Commission, 357 S.W.2d 701 (Ky. App. 1962) and Blue Grass State Telephone Co. v. Public Service Commission of Kentucky, 382 S.W.2d 81 (Ky. App.1964)), the Court upheld in National-Southwire Aluminum consideration by the KPSC of other factors. In particular, the Court held that the KPSC could consider "replacement cost, debt retirement, operating costs, and at least some excess capacity in order to insure continuation of adequate service during periods of high demand and some potential for growth and expansion." National Southwire Aluminum, 785 S.W.2d at 512. The KPSC could also consider "whether expansion investments were prudently or imprudently made, and whether a particular utility is investor owned or a cooperative operation." Id. The Court noted that the coal-fired plant was not like "an incomplete nuclear plant" and was "not a useless facility." Under these circumstances, the Court upheld the KPSC's order setting rates high enough for the rural electric cooperative to pay its debt on the plant under a workout plan, which plan allowed the cooperative to avoid bankruptcy and provided a longer pay-back period and lower interest rate. Id. at 513. As the Court explained, there is "no litmus test" for setting fair, just, and reasonable rates and "no single prescribed method to accomplish the goal." Id.

Once the rate base valuation is determined, the KPSC must set the rate of return on that rate base. See Public Service Commission of Kentucky v. Continental Telephone Co. of Kentucky, 692 S.W.2d 794, 798 (Ky. 1985) (citing Bluefield Water Works & Improvement as standard for determining rate of return). The method for setting rate of return may vary depending on the method used to value the rate base. Citizens Telephone Co. v. Public Service Commission of Kentucky, 247 S.W.2d 510 (Ky. App. 1952) (explaining that, where rate base is valued at reproduction costs, allowed return on capital may be lower than where rate base is valued at original cost).

Adjustment clauses.

Rates may include an automatic adjustment clause for costs of fuel used by the utility and fuel associated with purchased power. The adjustment clause may provide for periodic (monthly) adjustment per kilowatthour of sales equal to changes in fuel costs. Fuel costs under the adjustment clause include: the cost of fuel consumed in the utility's plants or the utility's share of fuel costs at jointly owned or leased plants; the cost of fuel that "would have been used in [such] plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation" resulting from such forced outages (807 KAR 5:056 §1(3)(a)); and certain costs of fuel associated with purchased power (807 KAR 5:056 §1(3)(b) and (c)). Every six months, the KPSC reviews the charges under the adjustment clause to correct for "improper calculation or application of the charges or improper fuel procurement practices." 807 KAR 5:056 §1(11). Every two years the KPSC reviews the past operation of the adjustment clause and may "disallow improper expenses" and reestablish the adjustment clause. 807 KAR 5:056 §1(12).

Moreover, the KPSC offered to adopt for certain electric utilities an optional earnings sharing mechanism (ESM) under which the amount of earnings above or below a specified earnings band is shared (on a 60 percent to 40 percent basis) between investors and ratepayers through an automatic monthly credit or surcharge (as appropriate) that is trued up annually in an expedited proceeding. Costs covered by the fuel adjustment clause (as well as the below-described environmental surcharge) are excluded from the calculations for the earnings sharing mechanism. Kentucky Utilities, 2000 WL 309957 at 20-21 (KPSC Jan. 7, 2000). This approach has been adopted for some utilities in the state. See Kentucky Utilities Co., 2000 WL 872715 at 5-6 (KPSC Jun. 1, 2000) and Louisville Gas and Electric Co., 2000 WL 872716 at 5-6 (KPSC Jun. 1, 2000). The KPSC is currently evaluating whether the earnings sharing mechanism is providing the intended incentives to improved performance. See Kentucky Utilities Co., 2003 WL 23336337 (Nov. 20, 2003) and Louisville Gas and Electric Co., 2003 WL 23336338 (Nov. 20, 2003). Apparently, the earnings sharing mechanism will be discontinued as of 2004.

Special provisions for costs of environmental compliance.

Under legislation enacted in 1992, the KPSC is required (starting January 1, 1993) to allow recovery through a rate surcharge, which is analogous to a fuel adjustment clause, for utilities' costs of complying with certain environmental requirements. Specifically, Kentucky statute provides that, "[n]otwithstanding any other provision of this chapter [278]," a utility "shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal" in accordance with a utility's approved compliance plan.[167] KRSA 278.183(1). The compliance costs include "a reasonable

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[167] Colorado, another coal state using more traditional utility regulation, has a similar provision stating that a public utility is "entitled to fully recover the air quality improvement costs that it prudently incurs" under a voluntary agreement with the Colorado Department of Public Health and Environment to reduce emissions. Colorado Revised Statutes (CRS) 40-3.2-102(1). The Colorado Public Utilities Commission must determine "an appropriate method of cost recovery that assures full cost recovery." CRS 40-3.2-102(3). See, e.g., Public Service Co. of Colorado, 1999 WL 716478 (Jun. 16, 1999) (recommended decision approving recovery of air quality improvement costs (including capital investment, return on capital, and operating costs) through "Air Quality Improvement Rider," a nonbypassable charge applied to all retail deliveries by utility); and Public Service Co. of Colorado, 2002 WL 32073085 (Dec. 19, 2002) (approving recovery of air quality improvement costs, i.e., early retirement of higher-emitting units and emission controls on other units, through "Air Quality Improvement Rider").

return on construction and other capital expenditures and reasonable operating expenses" (including operation and maintenance, taxes, and depreciation) "for any plant, equipment, property, facility or other action to be used to comply." Id. The costs must not be already reflected in existing rates. KRSA 278.183(2).

A utility may request such recovery through a rate "surcharge" applied starting in the second month after the month in which the costs to be recovered are incurred. At least 30 days in advance of commencing the surcharge, the utility must file a notice of intent to submit a plan for complying with the applicable environmental requirements and must subsequently file the plan. Id. Within six months of the filing, the KPSC must review the compliance plan and the rate surcharge, including the rate of return on the environmental capital expenditures. In addition, each monthly rate surcharge must be filed with the KPSC 10 days before going into effect. The KPSC must review the rate surcharge every six months and make a "temporary adjustment" to disallow any amounts that are "not just and reasonable" and to "reconcile past surcharges with actual costs." KRSA 278.183(3). The KPSC must also conduct review every two years and "disallow improper expenses" and incorporate the surcharge amounts into the utility's general rates. Id. In conducting these reviews, the KPSC does not carry out a full review of the utility's overall financial condition as is required in a general rate case. Instead, the KPSC separately considers the relevant environmental costs, in a manner analogous to the review of fuel costs in a review of a fuel adjustment clause. Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Co., 983 S.W.2d 493, 498 (Ky. Sup. Ct. 1998). On appeal, these provisions were upheld, with the Court holding that the Kentucky legislature had a legitimate interest in promoting "the use of Kentucky coal so as to provide jobs and other economic benefits in Kentucky" and to balance investor and ratepayer interests in a way that reflects that interest. Id. at 497; see also Kentucky Utilities Co., 2000 WL 309957 at 25 (KPSC Jan. 7, 2000) (holding that KRSA 278.183 provides a "stand alone cost recovery mechanism" separate from a general rate case).

The KPSC has approved use of this cost recovery mechanism for recovery of rate of return on construction work in progress and plant in service, depreciation, and operating costs for emission controls or waste handling through an environmental surcharge. See, e.g., Kentucky Utilities Co., 2003 WL 21246131 at 3-7 (KPSC Feb. 11, 2003) (allowing surcharge recovery for such costs for sulfur dioxide emission controls, but rejecting surcharge recovery of landfill site costs because costs were too uncertain for KPSC to determine reasonableness and cost-effectiveness of landfill site); and Kentucky Utilities Co., 2003 WL 21246128 at 2-4 (KPSC Feb. 11, 2003) (allowing surcharge recovery for such costs for fly and bottom ash pond dike).

Although the provision for surcharge recovery of the "costs of complying" with environmental requirements has been applied to emission controls or emission disposal property, it may be argued that the entire IGCC plant -- which integrates coal gasification, synthesis gas cleaning, combined cycle, and combustion emission control technologies to achieve clean use of coal to generate electricity -- is a means of "complying" with environmental requirements. However, it seems more likely that only certain elements (e.g., gasification and synthesis gas cleaning) of the plant will be treated as related to environmental compliance and that the costs of the other elements (e.g., coal handling equipment and combined cycle combustion and steam turbines) will be excluded from surcharge recovery.

The applicability of this provision (KRSA 278.183) is not stated as broadly as the Indiana provisions (e.g., IC 8-1-8.8-11 and 8-1-8.8-12) applying to "clean coal and energy projects" and "new energy generating facilities." While the Indiana provisions clearly cover an entire IGCC plant, the scope of the Kentucky provision is problematic. In addition, the Kentucky provision appears to require allowance of more rapid, but perhaps less certain, cost recovery than the Indiana provisions. Specifically, under KRSA 278.183 the utility may adjust the surcharge each month and pass through costs on an ongoing basis without upfront prudence review by the KPSC, but subject to KPSC review every six months and every two years. It seems that the KPSC can disallow costs and require refund of the pass-through as late as two or more years after the pass-through occurs, since the biennial review proceeding may take a number of months to complete. Further, although Kentucky statute establishes an entitlement to recovery for environmental compliance costs "[n]otwithstanding any other provision of" state utility law (KRSA 278.183(1)), it is not clear to what extent the KPSC will disallow recovery of costs of environmental compliance property that does not operate, or is not used, as intended under the environmental compliance plan. In contrast, the IURC allows the utility to adjust the charge under the adjustment clause every six months and to pass through the costs only after IURC review. It appears that once the IURC approves six-months' worth of capital expenditures, re-evaluation of the reasonableness of the expenditures is generally not allowed, in the absence of "fraud, concealment, or gross mismanagement," even if the facility is not completed. IC 8-1-8.7-7(d). See Sections 8.3, 9.3, and 9.4 below.

8.13. New Mexico

Jurisdiction.

In 1999, New Mexico enacted provisions for deregulating retail electricity generation and sales in 2001. See New Mexico Statutes Annotated (NMSA) 62-3A-1 through 62-3A-23. However, the New Mexico legislature subsequently postponed the commencement date for deregulation until 2007 and then, in a separate action, entirely repealed the deregulation provisions. New Mexico thus continues to retain a more traditional approach to electric industry regulation.

New Mexico statute establishes a state policy requiring the "regulation and supervision" of public utilities "to the end that reasonable and proper services shall be available at fair, just and reasonable rates, and to the end that capital and investment may be encouraged and attracted so as to provide for the construction, development and extension, without unnecessary duplication and economic waste, of proper plants and facilities for the rendition of service to the general public and to industry." NMSA 62-3-1(B). The New Mexico Public Regulation Commission (NMPRC) has jurisdiction over every public utility. "Public utilities" include any individual, firm, partnership, or company "not engaged solely in interstate business" that owns, operates, leases, or controls "any plant, property, or facility for the generation, transmission or distribution, sale or furnishing to or for the public of electricity for light, heat or power or other uses." NMSA 62-3-3(G)(1). However, unless a municipality elects to have its municipal utility regulated by the NMPRC, the municipal utility is excluded from NMPRC rate jurisdiction. NMSA 62-6-5. Further, the NMPRC has jurisdiction to review a rate change made: by rural electric generation or transmission cooperatives only if three or more New Mexico member utilities in the rural electric cooperative object to the rate change (NMSA 62-6-4(D)); and by other rural electric cooperatives if one or more members object (NMSA 62-8-7(G)).

A public utility may not begin construction or operation of "any public utility plant or system or of any extension to any plant or system" without first obtaining from the NMPRC "a certificate that public convenience and necessity require or will require such construction or operation." NMSA 62-9-1. In deciding whether to issue such a certificate, the NMPRC must give due regard to the public convenience and necessity, including, e.g., the avoidance of "unnecessary duplication and economic waste." NMSA 62-9-6. The requirement for a certificate does not apply to any extension that: is within the public utility's service area (as of July 13, 1941) or within or to an area already served by the utility, "necessary in the ordinary course of its business"; or is in a contiguous area not receiving similar service from another public utility. NMSA 62-9-1 See Sandel v. New Mexico Public Utility Commission, 980 P.2d 55, 58 (N.M. 1999) (describing general regulatory approach in New Mexico of giving vertically integrated utilities exclusive control of generation, transmission, and distribution in specific geographic areas and setting their rates).

The NMPRC has "general and exclusive power and jurisdiction to regulate and supervise every public utility in respect to its rates and service regulations and in respect to its securities." NMSA 62-6-4(A). However, the NMPRC regulates the "sale, furnishing or delivery of …electricity" to a public utility for resale and the "sale, furnishing or delivery of coal, uranium or other fuels by any affiliated interest" to a public utility only to the extent necessary for the NMPRC to determine that the cost to the public utility is "reasonable" and the methods of delivery of electricity are "adequate." NMSA 62-6-4(B) and (C).

Ratemaking process: rate changes; test year; rate base; and rate of return.

Every rate charged by a public utility must be "just and reasonable" (NMSA 62-8-1) and filed with the NMPRC (NMSA 62-8-3). A public utility cannot change its rates "except after thirty day's notice" to the NMPRC. NMSA 62-8-7(B). However, "for good cause shown," the NMPRC may allow a rate change to take effect without such prior notice. Id. The NMPRC must suspend operation of the new rates, if a hearing on the rates is necessary, for nine months after the effective date of the rate change and may extend the suspension for another three months. The NMPRC must "hear and decide cases with reasonable promptness." NMSA 62-8-7(C). In reviewing the rates, the NMPRC may determine "just and reasonable" rates or may require the utility to file new rates "designed" to produce revenues determined by the NMPRC to be just and reasonable. NMSA 62-8-7(D). The NMPRC may investigate a rate upon complaint that the rate is unjust or unreasonable or on its own motion and may issue orders affecting such rates. NMSA 62-10-1.

New Mexico statute does not specify the methodology to be used in setting just and reasonable rates. Otero County Electric Cooperative, Inc. v. New Mexico Public Service Commission, 774 P.2d 1050 (N.M. 1989). However, in setting rates, the NMPRC generally follows "the traditional elements of the ratemaking process and the establishment of the total revenue requirement," i.e., determination of cost of operation, rate base (which is the value of property "owned by the utility rendering service to the public") less depreciation, and rate of return. Hobbs Gas Co. v. New Mexico Public Service Commission, 616 P.2d 1116, 1118 (N.M. 1980); see also PNM Gas Service, 1 P.3d 383, 391 (N.M. 2000) (stating that NMPRC must set rates that are neither "unreasonably high so as to unjustly burden ratepayers with excessive rates nor unreasonably low so as to constitute a taking of property without just compensation or a violation of due process by preventing the utility from earning a reasonable rate of return on its investment"); and Sandel, 980 P.2d at 64 (reversing NMPRC's approval of market-based rates, rather than rates determined through ratemaking process).

With regard to determination of operating costs, the NMPRC evaluates a utility's costs for a historical year and "uses the utility's past experience as a guide to the utility's future revenue requirement." PNM Gas Service, 1 P.3d at 391. The test period may be a historical test year of 12 consecutive months ending not more than 150 days before the filing of new rates (adjusted for annualization and known and measurable changes) or a future test year of 12 consecutive months after the last 12 months of actual experience (adjusted for known and measurable changes and projected changes). New Mexico Administrative Code (NMAC) 17.9.530.7(S)(1) and (2). See, e.g., Gas Co. of New Mexico, 35 PUR4th 106, 127 (NMPRC Feb. 4, 1980) (adjusting historical test period data for known, measurable, and certain changes). The NMPRC generally uses the same time period as the test year for evaluating operating costs, revenues, and capital investment. See, e.g., Public Service Co. of New Mexico, 111 PUR4th 313, 369-70, 1990 WL 488711 (NMPRC Apr. 12, 1990).

In valuing utility property and business in order to determine rate base, the NMPRC must "give due consideration to the history and development of the property and business of the particular public utility, to the original cost thereof, to the cost of reproduction as a going concern, to the revenues, investment and expenses of the utility in this state and otherwise subject to the commission's jurisdiction and to other elements of value and rate-making formulae and methods recognized by the laws of the land for rate-making purposes." NMSA 62-6-14(A). In making determinations concerning public utility rates or service, the NMPRC may "change its past practices or procedures" if the change is justified by "substantial evidence" in the record. NMSA 62-6-14(C). Thus the NMPRC is not bound to use any specific method of property valuation but cannot rely solely on original cost. Hobbs Gas, 616 P.2d at 1119-20.

In particular, the NMPSC is not required to limit the rate base to property that is used and useful. New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission, 725 P.2d 244, 248-49 (N.M. 1986) (upholding the NMPRC's approach of allowing utilities to establish "inventory" of new electricity generation capacity above 20 percent reserve margin and to include plant plus accrued return on capital in rate base when plant becomes necessary to serve New Mexico customers). However, the Court in New Mexico Industrial Energy Consumers noted that the NMPRC had found that the specific utility decision at issue in that case (i.e., whether to build electricity generation capacity) was prudent and that the NMPRC's approach resulted in new capacity coming into rate base only when the capacity was put into service. Id. at 249; see also Public Service of New Mexico, 111 PUR4th at 318, 1990 WL 488711 (explaining that, under inventory approach, reasonableness and appropriateness of costs of plant could be challenged and, if any costs were disallowed, return on capital associated with disallowed costs would also be disallowed).

Although the NMPRC is not required to include, in rate base, only plant that is used and useful, the NMPRC generally treats the "used and useful" criterion as an important, albeit not dispositive, factor in determining what property to include in rate base. For example, in the case of property held for future use, the NMPRC has allowed such property to be included in rate base and thus in rates either if the property would be put into use shortly after the end of the test period for the rates or if the utility demonstrated that it had a plan to use the property in the foreseeable future and that inclusion in rate base would benefit ratepayers without imposing an undue burden. See, e.g., El Paso Electric Co., 29 PUR4th 427, 429-30 (NMPRC Jun. 8, 1979).

The NMPRC has similarly taken a flexible approach in deciding whether, and to what extent, to include construction work in progress in the rate base. When faced with the question of whether to include CWIP on a nuclear plant in rate base, the NMPRC, at least initially, did not allow inclusion of any such CWIP. See, e.g., El Paso Electric Co., 23 PUR4th 131, 137 (NMPRC Dec. 15, 1977) (denying inclusion of CWIP on nuclear plant not scheduled to go into service for five years, based on company's assurance that ratepayer financing of CWIP was not necessary to complete the plant, but suggesting different result if denial would cause "extensive financial hardship"). Subsequently, the NMPRC elaborated its analysis of rate-base inclusion of CWIP, stating that the factors considered in determining whether to include CWIP in rate base were: whether the construction program was reasonable; whether the construction could be financed without ratepayer participation before the plant was in service; and whether the construction was financed at the least cost. El Paso Electric, 29 PUR4th at 438-40 (denying inclusion of CWIP on nuclear plant, but approving CWIP on emission controls that would go into service during period that rates reflecting CWIP would be in effect). In El Paso Electric Co., 38 PUR4th 289, 340 (NMPRC July 24, 1980), the NMPRC further explained its criteria for inclusion of CWIP on a new electric generation plant in rate base, requiring an additional showing of "extensive financial hardship" to the utility and its customers without the inclusion of the CWIP in rate base. In that case, the NMPRC allowed in rate base some, but not all, of the CWIP on nuclear plant. In all these cases, the plants whose CWIP was allowed in rate base ultimately were completed and went into service; none of these were plants whose construction was started but was subsequently terminated.

The NMPRC has also taken a flexible approach to the application of the "used and useful" concept when addressing, in after-the-fact review, the extent to which completed excess capacity should be included in rate base. When a utility had a substantial amount of electricity generation capacity in excess of the amount needed to serve its retail customers reliably, the NMPRC rejected the approach of excluding from rate base all excess capacity as not being used and useful. Public Service Co. of New Mexico, 101 PUR4th 126, 169-75, 1989 WL 4185588 (NMPRC April 5, 1989), aff'd sub nom. New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission, 808 P.2d 592 (N.M. 1991). Instead, the NMPRC considered both a flexible "used and useful test" and a "financial health test" to determine what portion of the excess capacity should be treated as "used and useful" and included in the utility's rate base. Public Service of New Mexico, 101 PUR4th at 162-63, 1989 WL 418588. The NMPRC noted that the remedies available for excess capacity range from total inclusion of the capacity in rate base to total exclusion from rate base and that a "fair result" often involves a "sharing of costs" between investors and ratepayers. Public Service of New Mexico, 101 PUR4th at 163, 1989 WL 418588. After considering factors such as what was the amount of excess capacity, how long the capacity would remain excess, whether inclusion of any of the excess capacity in rate base would be just and reasonable, and what would be the economic consequences (e.g., the effect on the utility's financial health) of the rate treatment of the excess capacity, the NMPRC decided to include some, and exclude some, of the excess capacity (which included nuclear plant).[168]

Subsequently, with regard to the utility's nuclear units that the NMPRC allowed to be included in rate base, the NMPRC resolved the issue of the prudence of the utility's investment by approving a settlement disallowing a portion of the return of and on capital for the units. Public Service Co. of New Mexico, 110 PUR4th 69, 90-92, 1990 WL

[168] Under New Mexico statute, a public utility may own or operate an electric generating plant that is not intended to provide retail electric service to New Mexico customers, whose costs are not included in rate base and so are not reflected in New Mexico retail electric rates, and that is not subject to the NMPRC's rate jurisdiction. The NMPRC must ensure that "the regulated business is appropriately credited by any off-system sales made from regulated assets." NMSA 62-6-4.3(A).

488859 (NMPRC Mar. 6, 1990), aff'd sub nom. Attorney General of State of New Mexico v. New Mexico Public Service Commission, 808 P.2d 606 (N.M. 1991). However, in a later case, the NMPRC left open the possibility of additional disallowance of the cost of these units. Specifically, the NMPRC stated that it could "give no more assurances on the future ratemaking treatment" of the nuclear plants than "for any other utility asset in rate base" and, if the units become "wholly or partially unused or unuseful" in the future, additional return of or on capital for the units could be disallowed. Public Service Co. of New Mexico, 157 PUR4th 540, 563-64, 1994 WL 736326 (NMPRC Nov. 28, 1994). But see Public Service of New Mexico, 111 PUR4th at 330, 1990 WL 488711 (stating that utility need not show that these nuclear units warrant continued recovery of and on capital in next rate case); cf. Town of Norwood, Massachusetts v. Federal Energy Regulatory Commission, 80 F.3d 526, 531 (D.C. Cir. 1996) (upholding FERC allowing full recovery of unamortized capital investment, return on capital, and CWIP on nuclear plant that was in service for 31 years and has been prudently shutdown).

In setting the rate of return to be applied to the jurisdictional rate base, the NMPRC considers "current economic conditions, the present cost of capital, the rate of return of other enterprises having corresponding risk, and the principles of law governing the determination of just and reasonable rate for utilities." Southern Union Gas Co. v. New Mexico Public Service Commission, 503 P.2d 310, 313 (N.M. 1972). For example, a reasonable rate of return is one that provides an opportunity to receive just compensation for investment and fulfills the statutory goal in NMSA 62-3-1(B) of enabling a utility to attract capital. PNM Gas Service, 1 P.3d at 391. See also Behles v. New Mexico Public Service Commission, 836 P.2d 73, 80 (N.M. 1992) (stating that, in setting rate of return, there is a significant "zone of reasonableness…between utility confiscation and ratepayer extortion").

Adjustment clauses.

In 1975, the NMPRC adopted, for a major utility in the state, a new ratemaking methodology referred to as "cost-of-service indexing" or "COSI," under which rates were automatically adjusted on a periodic (at first, quarterly) basis when rate of return on the average book value of common equity for the period fell outside a range of 13.5 to 14.4 percent. Construction work in progress on environmental controls on existing plant, but not on new electricity generating plant, was allowed in rate base and thus in the equity portion of the rate base. See Public Service Co. of New Mexico, 8 PUR4th 113, 121-24 (NMPRC Apr. 22, 1975); see also Public Service Co. of New Mexico, 50 PUR4th 416, 418-23 (NMPRC Dec. 30, 1982) (describing history of cost-of-service indexing).

The NMPRC adopted cost-of-service indexing in order to enable the utility to attract new capital for new coal-fired and nuclear plants, which the NMPRC noted were more capital intensive than gas- and oil-fired plants. The NMPRC stated that coal and nuclear fuels had several advantages over gas and oil in terms of cost and reliability. Gas costs were increasing rapidly as compared to coal, and nuclear generation appeared to be cheaper than any fossil-fuel generation. Further, use of the enormous coal reserves and the uranium reserves in the U.S. would result in greater energy reliability and less dependence on foreign fuel. Public Service of New Mexico, 8 PUR4th at 119; see also Public Service of New Mexico, 101 PUR4th at 175, 1989 WL 418588 (explaining that fuel diversity minimizes risk of adverse changes in price or supply of a particular fuel resulting from unanticipated events, such as an oil embargo or adverse environmental impacts from fuel use). Because traditional cost-based ratemaking could not keep up with ongoing increases in utility costs, capital investment and cost of capital were not being recovered, and new capital investment was being discouraged. Public Service of New Mexico, 8 PUR4th at 119-21. Moreover, the NMPRC found that as the "earning stability and reliability of an energy utility are reduced, the market responds by increasing its cost of capital." Id. at 121.

According to the NMPRC, cost-of-service indexing would reduce risk and regulatory lag by restoring earnings stability and reliability, without reducing the utility's incentive "to resist cost increases and to effect economies." Id. at 132. Although rates were automatically adjusted, the NMPRC retained the right to review the rates using traditional cost-based ratemaking.

In 1979, the NMPRC reviewed the use of cost-of-service indexing. According to the NMPRC, cost-of-service indexing had the positive impacts of reduced cost of common equity and of improved ability to attract capital, but had the negative impacts of inadequate incentives to resist cost increases and effect economies and of reduced regulatory scrutiny due to overburdening of the NMPRC. Public Service of New Mexico, 50 PUR4th at 421-422. The NMPRC therefore changed the adjustment period for cost-of-service indexing from a quarterly to an annual adjustment period and based each new adjustment factor on a period consisting of ten months of actual data and two months of projected data. Further, each new adjustment factor was made subject to refund if an objection to any cost data underlying the calculation of return on common equity was received and accepted for hearing by the NMPRC. In the event of such an objection, the utility had the burden of demonstrating the prudence and reasonableness of each expense item subject to the objection. Id. at 422 and 427.

Finally, in 1982, the NMPRC terminated the use of cost-of-service indexing because the New Mexico legislature adopted a statutory provision (NMSA 62-8-7(E)) that the NMPRC interpreted as barring cost-of-service indexing. Id. at 423. The NMPSC also found that, while capital costs had been reduced, cost-of-service indexing resulted in less regulatory scrutiny and possibly "fueled [the utility's] ability to construct excessive capacity without concern for the long-term risks inherent to ratepayers and shareholders in such an endeavor." Id. at 451.

NMSA 62-8-7(E) provides that: "Except as otherwise provided by law, any increase in rates or charges for the utility commodity based upon cost factors other than taxes or cost of fuel, gas, or purchased power…shall be permitted only after notice and hearing, as provided by" NMSA 62-8-7(B) and (C) (requiring 30 day's notice and authorizing the NMPRC to suspend operation of new rates pending hearing for up to 12 months). The NMPRC is required to issue regulations "governing the use of tax, fuel, gas or purchased power adjustment clauses" and providing for consideration of several matters. NMSA 62-8-7(E). The matters that must be considered include: whether a particular adjustment clause is consistent with the purposes of utility regulation; what specific mechanism for recovery of such costs is to be used; what costs should be included; what procedures should be used to avoid inclusion of inappropriate costs; what methods should be used by the NMPRC for determining the "propriety" of costs "in a timely manner" (NMSA 62-8-7(E)(3)); and what adjustment period should be used. The NMPRC may eliminate or condition an adjustment clause if this action is consistent with the purposes of utility regulation and "will not place the affected utility at a competitive disadvantage." NMSA 62-8-7(F). The NMPRC must provide for "variances" and "separate examination of a utility's adjustment clause based upon that utility's particular operating characteristics." Id.

The NMPRC issued regulations implementing the adjustment clause provisions in NMSA 62-8-7(E). When making an initial application for a fuel and purchased power adjustment clause, a utility must show that: the cost of fuel and purchased power is a "significant percentage of the total cost of service" (NMAC 17.9.550.17(A)(1)); the cost "periodically fluctuates and cannot be precisely determined in a rate case" (NMAC 17.9.550.17(A)(2)); and the utility's policies and practices are designed to assure electricity is generated and purchased "at the lowest reasonable cost" (NMAC 17.9.550.17(A)(3)). In addition, the utility must show that the proposed adjustment clause is consistent with the goals of "adequate regulatory review" (NMAC 17.9.550.6(A)), "stability of utility earnings" when costs rise and "prompt credits" to customers when costs decline (NMAC 17.9.550.6(B)), and assurance of collection of "actually expended" costs (NMAC 17.9.550.6(C)). See NMAC 17.9.550.17(A) (requiring showing of consistency with purposes of rule). After approval of an adjustment clause, the utility must file every two years for continuation of the adjustment clause. The adjustment clause is deemed approved 30 days after the continuation filing unless the adjustment clause is suspended by the NMPRC. NMAC 17.9.550.18.

Prior to passage of NMSA 62-8-7(E), the NMPRC had allowed fuel and purchased power adjustment clauses in order to allow utilities to keep up with rapidly rising fuel costs, without repeated filings for increased rates and jeopardizing of cash flow. See ,e.g., Southwestern Public Service Co., 27 PUR4th 302, 320-21 (NMPRC Dec. 5, 1978). In applying the new statutory provisions, the NMPRC has allowed some, but not all, utilities to use fuel and purchased power adjustment clauses. For example, for one utility, the NMPRC eliminated entirely the fuel adjustment clause, and the accompanying credits for revenues from off-system electricity sales, that had previously been in effect. Public Service Co. of New Mexico, 157 PUR4th 579, 583, 1994 WL 736329 (NMPRC Nov. 28, 1994). The NMPRC explained that it considers the trade-off between "earnings stability" and “incentives” to minimize costs in determining whether to approve fuel adjustment clauses. Id. at 586. Because of the decline in inflation and the fact that fuel cost increases were more in line with inflation, the NMPRC terminated the utility’s adjustment clause.

Other utilities that demonstrated continued, rapid increases in fuel or purchased power costs or the potential for such increases have been allowed to use fuel and purchased power adjustment clauses. See, e.g., Texas-New Mexico Power Co., 2000 WL 1425094 at 8 (NMPRC Aug. 15, 2000) (approving fuel and purchased power adjustment clause with limitation on month-to-month fluctuations).

Retail electric competition: restructuring; nonbypassable charges; and provider of last resort.

Until New Mexico’s repeal of the utility deregulation legislation, the state’s more traditional approach to utility regulation (described above) was to be replaced by an approach requiring competitive retail electric generation and sales. The repealed legislation and implementing regulations are summarized below.

Under the repealed legislation, each public utility had to divide into at least two corporations in order to separate: “supply service and energy-related service consisting of generation and power supply facilities, operations and services and energy-related facilities,” to be made available to the public “on a competitive unregulated basis”; and transmission and distribution services “to be made available on a regulated basis.” NMSA 62-3A-8(B). Corporate separation could be accomplished by creating separate affiliated companies or separate unaffiliated companies or by selling assets to third parties. Unregulated service could not be provided by a regulated company. NMSA 62-3A-8(C). A utility was not required to “divest itself of any of its assets” that it owned or leased as of the effective date of the retail-electric-competition legislation. NMSA 62-3A-8(A).

Each public utility had to file a “transition plan” to implement deregulation of retail electric sales service. NMSA 62-3A-6. The transition plan had to include, inter alia: separation of “supply service and energy-related assets” from distribution and transmission assets consistent with NMSA 62-3A-8 (NMSA 62-3A-6(A)(1)); unbundled cost of service (NMSA 62-3A-6(A)(2)); projected “stranded costs” and “transition costs” (NMSA 62-3A-6(A)(8)); and “non-bypassable wires charges” for recovery of stranded and transition costs (NMSA 62-3A-6(A)(9)). “Stranded costs” were the difference between the net present value of generation-related “regulated revenue requirements” as of the commencement of retail sales competition that were recoverable in rates and the revenues “that could be earned from selling the same generation-related services” at competitive rates. NMSA 62-3A-3(Z). “Transition costs” were defined as the remaining costs of restructuring that were reasonable, prudent, and nonmitigable. NMSA 62-3A-3(CC).

The NMPRC was required to provide for recovery by a public utility of 50% of the company's stranded costs. However, recovery of up to 100% could be provided, but only if the NMPRC found that recovery exceeding 50% was in the "public interest" (NMSA 62-3A-6(B)(1)), "necessary to maintain financial integrity of the public utility" (NMSA 62-3A-6(B)(2)), and "necessary to continue adequate and reliable service" (NMSA 62-3A-6(B)(3)) and would not increase residential or small business rates during the stranded-cost recovery period (NMSA 62-3A-6(B)(4)).

The NMPRC had to set the nonbypassable wires charges for recovery of stranded and transition costs. With regard to stranded costs, the wires charges could be imposed for up to five years (or longer for nuclear decommissioning costs) and had to be "equitably designed in a competitively neutral manner." NMSA 62-3A-7(B)(3). With regard to transition costs, the wires charges could be modified in order to achieve full recovery, with crediting to customers for any overcollection. NMSA 62-3A-7(D). The wires charges would be imposed on every customer of a public utility, but only for system benefits for customers of rural electric distribution cooperatives or municipal utilities. NMSA 62-3A-14(A).

The public utility's transition plan also had to include: "standard offer service tariffs" for residential and small business customers that did not select a power supplier (NMSA 62-3A-6(A)(5)); and a proposed "procurement process or other process for selection of power supply for standard offer service" and rate setting procedures (NMSA 62-3A-6(A)(6)). A public utility had to design its electricity procurement to assure supply at the "lowest, reasonable price consistent with reliability, availability and portfolio requirements balancing local economic and environmental impacts." NMAC 17.9.591.10(A). Competitive bidding had to be used to produce supply for standard offer service unless the utility demonstrated that "another means [was] in the public interest." NMAC 17.9.591.10(B). Costs under the standard service offer had to be recovered through a purchased power adjustment clause. NMAC 17.9.591.9(C).

Special provisions for renewal-energy electric generation.

New Mexico recently passed a statute (Renewable Energy Act, Chapter 65, Laws of 2004) (REA) adopting a renewable portfolio standard for electric generation in the state. Underlying the statute are findings by the state legislature that, inter alia, use of renewable energy provides opportunities to "promote energy self-sufficiency, preserve the state's natural resources and pursue an improved environment in New Mexico" (REA Section 2.A(1)) and that public utilities should recover their "reasonable costs" of meeting the requirements of the statute (REA Section 2.A(4)). Within certain cost thresholds, each public utility's retail sales in New Mexico are required to comprise an increasing percentage, over time, of renewable energy: by 2006, five percent must be renewable energy, increasing one percent per year to ten percent in 2011 and thereafter. REA Section 4.A. The NMPRC must establish a system of renewable energy certificates that can be used to show compliance with such renewable portfolio requirements.

Certificates are generally owned by the generator of renewable energy and may be traded, sold, or otherwise transferred. Certificates are retired when used to meet a utility's renewable portfolio requirements and, if unused, may be carried forward for up to four years. REA Section 5. A public utility must "recover, through the rate-making process, the reasonable costs of complying with the renewable portfolio standard." REA Section 6.A. Each utility must submit an annual procurement plan for the next year, and costs consistent with an approved plan are deemed reasonable. REA Section 4.D and 6.A.

Unlike Indiana and Kentucky, New Mexico does not have provisions for ongoing review, approval, and recovery of capital expenditures, return on capital, and operating costs for new generation-related plant or equipment. Moreover, New Mexico statute and NMPRC precedent include certain provisions or policies that seem to be inconsistent with the provision of an assured revenue stream for new IGCC plants under the 3Party Covenant. These provisions or policies include: a statutory prohibition of the use of adjustment clauses, except for fuel, purchased power, and taxes; NMPRC precedent for re-evaluation of past "used and useful" determinations for electricity generating plant; and NMPRC precedent strictly limiting inclusion of CWIP in rate base. See Sections 8.3, 9.3, and 9.4 below.

8.2. States with competitive retail electricity generation and sales.

8.21. Ohio.

Jurisdiction.

Until January 1, 2001 when the Public Utilities Commission of Ohio (PUCO) began to implement "competitive retail electric service" under the state's utility deregulation statute, Ohio followed a more traditional approach of regulating electric utilities as vertically integrated monopolies with designated service areas. The PUCO is granted "power and jurisdiction to supervise and regulate public utilities." Ohio Revised Code Annotated (ORCA) 4905.04(A). Ohio statute defines "public utility" as including any "electric light company, when engaged in the business of supplying electricity for light, heat, or power purposes to consumers" (ORCA 4905.03(4)), with exceptions for municipal utilities and non-profit electric light companies, and utilities owned and operated exclusively by and for their customers (e.g., rural electric cooperatives) (ORCA 4905.02). An electric light company (also referred to as an "electric supplier") has a "certified territory" in which the company has the "exclusive right to furnish electric service to all electric load centers." ORCA 4933.83(A). In general, an electric light company's "certified territory" is its service area as of 1978. See ORCA 4933.82(B). The company may not extend electric service to load centers in another company's certified territory. ORCA 4933.83(A). (Under the regulatory system in place until 2001, "electric service" included retail electric generation, which starting in 2001, was exempted from "electric service." See ORCA 4933.81(F).) However, municipalities retain the right to generate, transmit, distribute, or sell electricity. ORCA 4933.87; see Toledo Edison Co. v. City of Bryan, 737 N.E.2d 529, 533 (Ohio 2000) (holding that municipalities may generate or purchase electricity for residents but not for the purpose of selling outside municipal boundaries).

Before construction of a "major utility facility," including any electricity generating plant of 50 MW or more (ORCA 4906.01), can commence, a certificate must be issued for the facility by the PUCO's power siting board. ORCA 4906.04. There is an exception for the certificate requirement for replacement of an existing facility "with a like facility." Id. In issuing a certificate, the board must make findings on the need for the facility and the nature of the facility's probable environmental impact and on whether the facility will serve the "public interest, convenience, and necessity." ORCA 4906.10(A)(6).

Ratemaking process: rate changes; test period; rate base; and rate of return.

The PUCO determines "just and reasonable rates" for public utility service (which until 2001 included retail electric service). ORCA 4905.22 and 4909.15(A). A public utility must file an application to establish or change any rate. ORCA 4909.18. When the PUCO fails to issue a final order on a proposed rate increase within 275 days, the rate goes into effect subject to refund, if the utility provides an "undertaking" payable to the PUCO in order to ensure refunds will be made as appropriate. If the PUCO does not issue a final order within 545 days, the utility has no refund requirement for amounts collected after the latter deadline. ORCA 4909.42. The PUCO may determine that a rate being charged or proposed to be charged is unjust or unreasonable and set the just and reasonable rate to be charged. ORCA 4909.15(D).

In determining just and reasonable rates for a public utility, the PUCO must determine: a "fair and reasonable rate of return" on the value of public utility property (ORCA 4909.15(A)(2)); and the "cost to the utility of rendering the public utility service" for a test period (ORCA 4909.15(A)(4)). Determination of a "fair and reasonable rate of return" is "prospective" and must be based on current, not historical, data. Babbit v. Public Utility Commission of Ohio, 391 N.E.2d 1376, 1383 (Ohio 1979). The test period for determining a public utility's cost of service is generally a 12-month period starting six months before the application for rates or a rate change is filed and not ending more than nine months after such filing. The PUCO can order use of a different test period. ORCA 4909.15(C). Generally, test year revenues and expenses may not be adjusted in order to set rates. Dayton Power & Light Co. v. Public Utility Commission of Ohio, 447 N.E.2d 733, 736-37 (Ohio 1983). The exception is where adjustment is necessary to prevent "an anomaly in the ratemaking equation, making the test year unrepresentative for ratemaking purposes." Board of Commissioners of Montgomery County v. Public Utility Commission of Ohio, 438 N.E.2d 111, 113 (Ohio 1982).

The property value on which rates are based is generally the value of the property that is "used and useful for the service and convenience of the public." ORCA 4909.04(A). The property value must be determined as the original cost (ORCA 4909.05(C) through (G)), less depreciation and contributions of capital (ORCA 4909.05(H) and (I)), of property used and useful as of "the date certain determined by" the PUCO. ORCA 4909.15(A)(1). See, e.g., Office of Consumers' Counsel v. Public Utility Commission of Ohio, 391 N.E.2d 311 (Ohio 1979) (rejecting inclusion in rate base of investment in nuclear plant that was not providing beneficial service to ratepayers as of the date on which utility property was valued for rate purposes, although the plant provided beneficial service as of a later date). These provisions were applied to deny or limit recovery of capital investment and return on capital for cancelled nuclear plants. See, e.g., Office of Consumers' Counsel v. Public Utility Commission of Ohio, 423 N.E.2d 820, 827 (Ohio 1981) (holding that PUCO lacks statutory authority to treat expenditures for cancelled nuclear plant as amortized operating costs because, even though investment decision and decision to cancel were prudent when made, expenditures were "an investment that never provided any service whatsoever to the utility's customers"); Dayton Power & Light, 447 N.E.2d at 740-45 and Cleveland Electric Illuminating Co. v. Public Utilities Commission of Ohio, 447 N.E.2d 746 (Ohio 1983), cert. den., 464 U.S. 802 (1983) (affirming PUCO's denial of cancelled nuclear plant expenditures as amortized costs); and City of Cincinnati, 620 N.E.2d 826 (explaining that, where uncompleted nuclear plant was converted to coal-fired plant, PUCO disallowed recovery of non-used-and-useful portion of capital investment in nuclear plant and allowed recovery of remainder of capital investment as associated with coal plant). In setting return on equity, the PUCO can take into account the increased risk to investors that results from the inability to recover costs of cancelled plant. Office of Consumers' Counsel v. Public Utilities Commission of Ohio, 447 N.E.2d 749, 753-54 (Ohio 1983).

However, the PUCO can include in rates an "allowance for construction work in progress" up to 10 percent of the total valuation of the project involved. The project must be at least 75 percent completed before the allowance can be included in rates. ORCA 4909.15(A)(1). A provision, repealed effective January 1, 2000, increased the allowance under this provision to 20 percent of the total valuation if the project was for pollution control equipment.[169] [170] The PUCO has "broad discretion" in applying this provision,

[169] Illinois, another coal state that has now deregulated retail electricity sales, has a similar provision for recovery of return on capital for construction work in progress for "pollution control devices for the control of sulfur dioxide emissions." 220 Illinois Compiled Statutes (ICS) 5/9-214(f).

[170] Pennsylvania, another coal state that has now deregulated retail electricity sales, has provisions favoring the use of coal, e.g., a provision for inclusion in rate base of CWIP for up to 50% of the cost of increasing the capacity to use coal in existing coal-fired plants. 66 Pennsylvania Consolidated Statutes (PCS) 514(c). In addition, the Pennsylvania Public Utility Commission (PPUC) must issue regulations requiring utilities to increase their generating capacity through increased capacity to use coal at existing coal-fired facilities where "economically feasible" and "beneficial to ratepayers" and establishing a "special cost recovery and shared benefits procedure" as an incentive for such capacity increases. 66 PCS 514(a) and (b). The PPUC also must order conversion of existing oil- or gas-fired units to coal or coal-derived fuel, unless conversion is not feasible, the converted unit cannot meet environmental requirements, or the converted unit would be more costly to ratepayers. Reasonable and prudent costs of a required conversion are recoverable, even if the conversion or operation of the converted unit is "ultimately prevented by factors beyond the utility's control," and can be included in rate base during construction. 66 PCS 517(a) and (d). Finally, a utility can construct a new nuclear or oil- or gas-fired unit only with PPUC approval. The PPUC can approve this only

which, for example, is not subject to any test period restriction. Columbus & Southern Ohio Electric Co. v. Public Utilities Commission of Ohio, 460 N.E.2d at 1111 (Ohio 1984). The allowance may be included in rates for no more than 48 months, with the possibility of an extension of up to 12 more months for good cause. If the project is cancelled, abandoned, or terminated, then the allowance must be excluded from rates "immediately" and offset against future revenues. ORCA 4909.15(A)(1). See Columbus & Southern Ohio Electric, 460 N.E.2d 1108 (upholding PUCO order reversing inclusion of construction work in progress in rate base in light of indefinite suspension of plant construction).

Before its repeal effective January 1, 2001, ORCA 4913.05 provided another exception to a strict "used and useful" requirement. If the PUCO approved a plan for compliance with certain requirements of the Acid Rain Program under Title IV of the Clean Air Act, the utility incurred costs for emissions control equipment under the plan, and the PUCO subsequently withdrew approval of the plan due to "substantial or extraordinary changes in circumstances," then the PUCO could approve recovery of "reasonably incurred" costs for the equipment.[171] ORCA 4913.05(G) (repealed effective Jan. 1, 2001). Return on capital for construction work in progress for such equipment could be recovered through a surcharge on the utility's rates. ORCA 4090.19.2 (repealed effective Jan. 1, 2001). The provision in ORCA 4913.05(G) was apparently never applied.

Adjustment clauses.

Prior to repeal effective January 1, 2001 of the statutory adjustment-clause provisions discussed in this section, the PUCO could allow pass-through of costs of fuel used by the utility and fuel associated with purchased power in a fuel adjustment clause. See ORCA 4905.01(G) (definition of "fuel component"; repealed effective Jan.1, 2001) and 4909.15.9 (limiting purchased power costs in fuel adjustment clause to fuel used for generation; repealed effective Jan. 1, 2001); see also Montgomery Count Board of Commissioners v. Public Utilities Commission of Ohio, 503 N.E.2d 167 (Ohio 1986) (barring inclusion, in fuel adjustment clause, of non-fuel costs not expressly authorized for such recovery in statute); and Cleveland Electric Illuminating Co., 154 PUR4th 418, 428, 1994 WL 526118 (PUCO Aug. 10, 1994) (rejecting inclusion of demand-side management costs in fuel adjustment clause because of insufficient "nexus" between demand-side management programs and reduction in per unit fuel costs and explaining

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if no sites are reasonably available for a comparable unit using coal or coal-derived fuel in compliance with environmental requirements or if such comparable unit would be more costly for ratepayers. 66 PCS 519 and 521.

[171] Pennsylvania similarly has a provision for PPUC review and approval of each utility's plan, upon request by the utility, to bring coal-fired units into compliance with the Acid Rain Program. 66 PCS 530(a) and (b). Upon approval of the plant, reasonable and prudent compliance costs for "desulfurization devices, clean coal technologies, or similar facilities designed to maintain or promote" (66 PCS 530(d)(2)(ii)) coal use are "recoverable costs of service" (66 PCS 530(d)(2)). Such costs qualify as "nonrevenue-producing investments" that are not required, under 66 PCS 1315, to be "used and useful" in order to be included in rate base or otherwise included in rates. 66 PCS 530(d)(3).

that without such a “connection” requirement any equipment that increased fuel efficiency could be included in fuel adjustment clause).

The fuel component was calculated based on base period fuel costs and purchased power costs (i.e., fuel used to generate purchased power or total purchased power costs for power not exceeding the utility’s incremental fuel cost for its own generation). Ohio Administrative Code (OAC) 4901:1-11-01(I) (definition of ”economic power”) and 4901:1-11-04(B) through (D). A reconciliation procedure was used to correct any over- or under-recovery of costs. OAC 4901:1-11-06.

The PUCO required electric utilities to make a showing every six months, in an expedited hearing, that the fuel costs were “fair, just, and reasonable.” OAC 4901:1-11-11(B). The PUCO could defer inclusion of costs in the fuel component if their appropriateness was “questionable,” pending submission of evidence that they were “properly includable.” OAC 4901:1-11-08(B). The PUCO was required to review the fuel component at least annually, or upon request, if changes in acquisition and delivery costs or in system operations caused or could cause at least a 20 percent change in the fuel component. ORCA 4905.30.1 (repealed effective Jan. 1, 2001). The electric utility had to charge its most recently approved fuel component until the PUCO changed the fuel component. OAC 4901:1-11-12.

Ohio coal research and development costs could also be included in the fuel component.[172] ORCA 4905.30.1 and 4909.19.1(B) (repealed effective January 1, 2001); see also OAC 4901:1-11-03(B). The Ohio Coal Development Office is charged with encouraging, promoting, and supporting “siting, financing, construction, and operation of commercially available or scaled facilities and technologies, including, without limitation, commercial-scale demonstration facilities and, when necessary or appropriate to demonstrate the commercial acceptability of a specific technology, up to three installations within this state utilizing the specific technology, to more efficiently produce, beneficiate, market, or use Ohio coal.” ORCA 1551.32(A)(1). Priority is to be given to technologies that “enable maximum use of Ohio coal in an environmentally acceptable, cost-effective manner.” ORCA 1551.32(B). The Ohio Coal Development Office reviews proposals for coal research and development projects to be supported by a state loans, load guarantees, or grants and may recommend recovery of the costs of such a project through the utility rates. While, on the face of the statute, the recovery through utility rates seems to be limited to projects undertaken by a gas or natural gas company (ORCA 4905.30.4), the costs could be recovered by an electric utility as well through its fuel component. See OAC 4901-11-05. In one case, a gas utility was allowed to recover its share of costs associated with emission controls under a coal research and

[172] Illinois similarly has fuel adjustment clause provisions favoring the use of coal. Specifically, Illinois allows inclusion as a fuel cost, recoverable in a fuel adjustment clause, “any fees paid by the utility for the implementation and operation of a process for desulfurization of the flue gas when burning high sulfur coal at any location” in Illinois. 220 ICS 5/9-220(a).

development project at an electricity generating plant. See East Ohio Gas Co., 1994 WL 73500 at 2 (PUCO Feb. 3, 1994) (approving recovery of gas utility's costs in gas reburn and sulfur dioxide and nitrogen oxide control projects at electricity generating plant as coal research and development costs included in adjustment clause).

Retail electric competition: restructuring; and nonbypassable charges for transition costs.

Ohio's retail electric competition statute makes the above-described regulatory system inapplicable to retail electric generation and sales starting in 2001 and requires functional unbundling of electricity distribution from electricity generation and transmission. The Ohio statute declares that it is state policy to, inter alia: "[e]nsure the availability to consumers of adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service" (ORCA 4928.02(A)); "[e]ncourage innovation and market access for cost-effective supply- and demand-side retail electric service" (ORCA 4928.02(D)); and "[e]nsure effective competition in the provision of retail electric service by avoiding anti-competitive subsidies" (ORCA 4928.02(G)). The shift to deregulated retail electric service is phased in, with a five-year transition period ("market development period") in which costs associated with deregulation may be recovered.

"Retail electric service" is defined as any service "involved in supplying or arranging for the supply of electricity to ultimate consumers" in Ohio, from "the point of generation to the point of consumption." ORCA 4928.01(A)(27). This includes generation, aggregation, power marketing, power brokerage, transmission, distribution, ancillary service, metering, and billing and collection. Id. Of these components of retail electric service, the portion that is required by statute to be "competitive" includes "retail electric generation, aggregation, power marketing, and power brokerage services." ORCA 4928.03. The PUCO may determine that additional components of retail electric service must also be competitive. ORCA 4928.04.

Starting January 1, 2001, "competitive retail electric service" is not subject to "supervision or regulation" by the PUCO under ORCA 4901 through ORCA 4909 (which are the provisions establishing the above-described, more traditional regulatory system) with limited exceptions concerning, e.g., discriminatory rates and conditions, certified territories, and service reliability and public safety. Control of transmission facilities in Ohio must be transferred to qualifying independent transmission entities. ORCA 4928.12. Further, each electric utility (e.g., each electric light company engaged in both competitive and noncompetitive retail electric service) must implement a "corporate separation plan" approved by the PUCO. ORCA 4928.17(A). The plan must: include the provision of competitive retail electric service through a "fully separated affiliate" (ORCA 4928.17(A)(1)); satisfy the public interest in "preventing unfair competitive advantage and…abuse of market power" (ORCA 4928.17(A)(2)); and ensure that the company will not extend "undue preference or advantage" to any affiliate, division, or part of its business that supplies competitive retail electric service (ORCA

4928.17(A)(3)). The PUCO may, for good cause, shown, approve “for an interim period” a plan that does not provide for a fully separated affiliate but that complies with “functional separation requirements.” ORCA 4928.17(C).

Ohio statute requires that, after a transition period, each electric distribution utility (i.e., each electric utility that provides retail electric distribution service) provide “a market-based standard service offer of competitive retail electric services” within its certified territory (ORCA 4928.14(A)) and the option to purchase such services through a “competitive bidding process” (ORCA 4928.14(B)). The PUCO must ensure that competitive retail electric service is provided at “compensatory, fair, and nondiscriminatory” prices, terms, and conditions if the PUCO determines that there is a “decline or loss of effective competition” for such service provided by an electric utility. ORCA 4928.06(B). Further, the PUCO is authorized to “resolve abuses of market power by any electric utility that interfere with effective competition.” ORCA 4928.06(E)(1). In particular, the PUCO may take measures to ensure that retail electric generation service is provided “at reasonable rates” in a “transmission constrained area” in a utility’s certified territory if the PUCO finds that the utility engaged in “abuse of market power” that is “not adequately mitigated” by any “independent transmission entity controlling the transmission facilities.” ORCA 4928.06(E)(2).

Each electric utility must submit for approval by the PUCO a “utility transition plan.” ORCA 4928.31(A). The plan includes the major components for the transition to competitive retail electric service. First, the plan must include a plan for unbundling utility rates, as well as the above-described corporate separation plan. The electric utility is required to file separate (i.e., “unbundled”) rate components for electricity generation, transmission, and distribution to be charged during the market development period. ORCA 4928.34. During the market development period, the utility functions as the provider of last resort in that the utility is required to make available to all retail customers in the utility’s certified territory “a standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers including a firm supply of electric generation service.” ORCA 4928.35(D). If another supplier fails to provide service, the suppliers’ retail customers default to the standard service offer until the customers chose another supplier. Id. In order for the unbundled rates to be approved, the total revenue from all unbundled rates must be capped and equal the total revenues from the utility’s most recent bundled rates. ORCA 4928.34(A)(6).

Second, the utility transition plan may include an application for the opportunity to receive revenues for transition costs. During the market development period, the electric utility receives such revenues from competitive retail electric service in its certified territory through: the approved, unbundled rates paid by its customers for retail electric generation; and an approved, “nonbypassable and competitively neutral transition charge” paid, per kilowatthour purchased, by those customers in its certified territory who obtain retail electric generation from another company. ORCA 4928.37(A)(1)(b). The transition charge is not payable on electricity supplied by a municipal utility to retail customers if the municipal utility provides transmission or distribution through its facilities and was operating as of January 1, 1999. The charge is also not payable on electricity produced and consumed in Ohio by a self-generator (i.e., a facility producing electricity "primarily for the owner's consumption" (ORCA 4928.01(33))). ORCA 4928.37(A)(2)(b).

In essence, the utility is allowed to impose, as a nonbypassable charge, a charge for access to the wires by retail customers. The only costs that may be included in the transition charge are the "just and reasonable transition costs" that: were "prudently incurred"; are "legitimate, net, verifiable, and directly assignable or allocable to retail electric generation service" in Ohio; and are "unrecoverable in a competitive market" but otherwise recoverable by the utility. ORCA 4928.39(A) through (D). These costs include the costs of "regulatory assets," which are unamortized, non-recurring expenses whose recovery was deferred by the PUCO (e.g., deferred taxes and employee benefit and retirement costs), as well as stranded generation assets. ORCA 4928.39. The transition charge includes "shopping incentives" to encourage the development of effective competition in retail electric generation service, e.g., sufficient incentives to induce shifting to a company other than the electric utility by at least 20 percent of the retail electric service load by the end of 2003. ORCA 4928.40(A). The transition charges may be reviewed and adjusted no more often than annually. ORCA 4928.40(B)(1). The portions of the charge that are based on regulatory assets are subject to adjustment only prospectively and generally only after December 31, 2004. ORCA 4928.39.

The nonbypassable charge provides an opportunity for the utility to recover transition costs, but actual revenues from the charge may be more or less than these costs. <u>AK Steel Corp. v. Public Utilities Commission of Ohio</u>, 765 N.E.2d 862, 866 (Ohio Ct. App. 2002). The electric utility is "wholly responsible" for "how to use" transition revenues and for "whether it is in a competitive position" after the market development period. ORCA 4928.38. However, the PUCO may impose requirements to ensure that the revenues are used to "eliminate the allowable transition costs" during the market development period and are not available for use to achieve undue competitive advantage by the electric utility. ORCA 4928.39.

Third, the utility transition plan may include a plan for transferring control of the electric utility's transmission facilities to an independent entity. ORCA 49028.31(A). In the absence of an approved independent transmission plan, the PUCO must order transfer of the transmission facilities to an independent entity to be operational by the end of 2003. ORCA 4928.35(G).

The PUCO has approved utility transition plans for a number of electric utilities. Under these approved plans, the utilities were generally allowed to retain ownership of their electricity generating plants, transfer control of their transmission facilities, and recover transition costs through a nonbypassable transition charge. <u>See, e.g.,</u> <u>Monongahela Power Co.</u>, 2000 WL 1873291 at 2 (PUCO Oct. 5, 2000), <u>reh'g den.</u>, 2000 WL 33175454 (PUCO Nov. 21, 2000) (approving utility transition plan with transfer of operational control of transmission assets and with transition charge for regulatory assets); Columbus Southern Power Co., 2000 WL 1873290 at 5-6 and 21-22 (PUCO Sept. 28, 2000), clarified, 2000 WL 33191552 (PUCO Nov. 21, 2000), stay den., Columbus Southern Power Co., v. Public Utility Commission of Ohio, 745 N.E.2d 1052 (Ohio 2001) (approving utility transition plan with transfer of operational control of transmission assets and future transfer of ownership of transmission and distribution assets to new affiliates and with transition charge for regulatory assets and (except for switching customers) stranded generation assets)); Dayton Power and Light Co., 2000 WL 1751554 at 5-9 and 12-13 (PUCO Sept. 21, 2000), reh'g den., 2000 WL 33118630 (PUCO Nov. 30, 2000) (approving utility transition plan with transfer of operational control of transmission assets and future transfer of ownership of transmission and generation assets to affiliates and with transition charge for regulatory assets); Cincinnati Gas & Electric Co., 2000 WL 1751385 at 4, 7-8, and 38-40 (PUCO Aug. 31, 2000), reh'g den., 2000 WL 1876395 (PUCO Oct. 18, 2000) (approving utility transition plan with transfer of operational control of transmission assets, with conduct of competitive retail service through affiliate and future transfer of ownership of generation assets, and with transition charge for regulatory assets (including future purchased power costs)); and FirstEnergy Corp., 203 PUR4th 102, 113 and 121-26, 2000 WL 1791792 (PUCO Jul. 19, 2000), reh'g den., 2000 WL 1876876 (PUCO Sept. 13, 2000) (approving utility transition plan with transfer of operational control of generation assets to business unit and future division of ownership of company assets among generation, transmission and distribution, and support services affiliates and with transition charge for regulatory assets and stranded generation assets). See also Ohio Edison Co., 233 PUR4th 349, 2004 WL 1493955 (Jun. 9, 2004) (indicating need for additional filing by utility concerning corporate separation). Although the utility transition plans provided, in the future, for ownership of generation assets by a separate company from the company owning transmission or distribution assets, only one of the utilities has completed such a corporate separation, and it is not clear when such corporate separations will take place.

After the market development period (which terminates by the end of 2005 or sooner, if approved by the PUCO), the electric utility will no longer receive “transition revenues” or “equivalent revenues.” ORCA 4928.38. However, the PUCO may allow recovery of revenue requirements for regulatory assets through December 31, 2010. ORCA 4928.40(A).

Retail electric competition: provider of last resort and related nonbypassable charges.

Also after the market development period, each electric utility must provide, “on a comparable and nondiscriminatory basis within its certified territory, a market-based standard service offer of all competitive retail electric services necessary to maintain essential electric service to consumers, including a firm supply of electric generation service” (ORCA 4928.14(A)) and the option to purchase competitive retail electric service at a price determined through a “competitive bidding process” in which any generation supplier may participate (ORCA 4928.14(B)). However, the PUCO recently indicated that a competitive retail generation market will likely not be "fully mature and robust" in Ohio by the end of 2005 and approved negotiated standard-service-offer rates for a utility for 2006-2008. Ohio Edison Co., 233 PUR4th 349, 2004 WL 1493955. See also Dayton Power and Light Co., 227 PUR4th 1, 18-19 and 23-25, 2003 WL 22142843 (PUCO Sept. 2, 2003), rehg. den. in relevant part, 2003 WL 22964799 (PUCO Oct. 22, 2003) (noting that PUCO had approved ending market development period on December 31, 2003, but extending period to December 31, 2005 due to lack of effective competition and approving negotiated standard-service-offer rates for 2006-2008). The electric utility is the provider of last resort in that, for its certified territory, if another supplier fails to provide electricity generation service for retail customers, service must be provided under the electric utility's standard service offer. There is no time limit on the requirement to function as the provider of last resort. See ORCA 4928.14(C). An electric distribution utility may require, pursuant to an approved tariff, a retail electric generation service provider to "issue and maintain a financial instrument" to protect against default in the provision of retail electric generation service. OAC 4901:1-24-08(A).

The PUCO has interpreted the provider-of-last resort requirement as providing a basis for imposing certain costs related to an electric utility's electricity generating plants on all retail electric generation customers, including those customers served by other electricity suppliers. Dayton Power and Light, 2003 WL 22964799 at 5 (stating that utility has "costs that are associated with the possible return of customers" and should be "compensated for these costs"). The costs (in that case, costs reflecting fuel price increases, compliance with environmental and tax requirements, and physical security and cyber-security) were allowed to be recovered up to a capped amount, through a rider (i.e., a "rate stabilization surcharge"). Id. The PUCO stated that, while it was not finding that these costs were provider-of-last resort costs, "the existence of [provider-of-last-resort] costs makes it reasonable to apply the [surcharge] to all customers." Dayton Power and Light, 227 PUR4th 1, 26, 2003 WL 22142843. See also Ohio Edison Co., 233 PUR4th 349, 2004 WL 1493955 (approving rate stabilization charge for all customers covering utility's risk (and not based on utility's costs) in providing provider-of-last-resort service at fixed rate during 2006-2008).

One electric utility has argued before the PUCO that the company should be able to pass through, in a nonbypassable charge, the costs of investment in electricity generating plant necessary to maintain a specified generation reserve margin. According to the utility, this charge will compensate for the company's statutory obligation, as the provider of last resort, to stand ready at all times to serve all retail load in its certified service territory. Initial Comments of the Cincinnati Gas & Electric Company, Case No. 03-93-EL-ATA at 8-16 (Mar. 4, 2003). The PUCO has not yet ruled on the utility's request.

The PUCO may also establish riders on the rates for retail electric distribution service. The riders may cover costs for assistance to low income customers or consumer education or costs for an energy efficient revolving loan fund. ORCA 4928.52; and

ORCA 4928.61. Like the nonbypassable charge for transition costs, the riders are wires access charges paid by retail customers. Ohio statute does not appear to currently authorize nonbypassable wires charges for any other types of cost.

In contrast with the more traditional electric industry regulatory systems in Indiana, Kentucky, and New Mexico, retail electric competition in Ohio generally puts the full risk of new electricity generating plant on investors and makes investors' recovery of costs subject to the operation of the electricity market. In general, this approach is inconsistent with the provision of an assured stream of revenues for new IGCC plants under the 3Party Covenant. See Sections 8.3, 9.3, and 9.4 below.

8.22. Texas.

Jurisdiction.

Until January 1, 2002 when the Public Utility Commission of Texas (TPUC) began implementing retail electric competition in most of the state under the state's utility deregulation statute, Texas followed a more traditional approach of regulating electric utilities as vertically integrated monopolies with designated service areas. The TPUC is granted "general power to regulate and supervise the business of each public utility," including each electric utility (Texas Utilities Code Annotated (TUCA) 14.001), and specifically has jurisdiction over "rates, operations, and services" of an electric utility (TUCA 32.001(a)). The term "electric utility" is defined generally as any person that "owns or operates for compensation in this state equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity in this state." TUCA 31.002(6). However, there are several exceptions to the general definition, including a municipality, a qualifying facility, an exempt wholesale generator, a power marketer (i.e., a person who owns electricity for wholesale sale but owns no generation, transmission, or distribution facilities in the state and has no certificated service areas), a rural electric cooperative,[173] and a person owning or operating equipment "used primarily to produce and generate" electricity for his own consumption (TUCA 31.002(6)(J)(ii)). (As discussed below, the state's utility deregulation statute amended the definition of "electric utility" to add exclusions for a "retail electric provider" and a "power generation company.") Each municipality regulates local utility service within the municipality, with the TPUC exercising a review function, but municipalities may elect to have the TPUC exercise original jurisdiction over such utility service. TUCA 32.001(a)(2), 33.002, and 33.052.

An electric utility may not provide service to the public "under a franchise or permit" unless the company first obtains a certificate of convenience and necessity. TUCA 37.051(a). The TPUC may issue a certificate for a service area (or a facility) only if "necessary for the service, accommodation, convenience, or safety of the public." 16

[173] Before 1997, under certain circumstances, the TPUC could review the rates of rural electric cooperatives providing retail service. See TUCA 36.251 and 36.307.

Texas Administrative Code (TAC) 25.101(b). A certificate or certificate amendment is required for, inter alia, a change in service area or a new electricity generating unit "constructed, owned, or operated by a bundled electric utility." TAC 25.101(b)(2). Further, a "retail electric utility" may not provide service to an area where another "retail electric utility" is lawfully providing service unless the former company first obtains a certificate of convenience and necessity. TUCA 37.051(b). The TPUC may not grant a certificate if that would result in an area being "multiply certificated" unless the certificate holder is not, and is not capable of, providing adequate service. TUCA 37.060(h).

Until the provisions were repealed effective September 1, 1999, Texas statute required each electric utility to submit a preliminary, ten-year integrated resource plan including a forecast of demand and necessary supply. TUCA 34.021 and 34.022. After the plan was approved, the electric utility had to solicit bids in accordance with the plan and could receive bids from affiliates and request a certificate of "convenience and necessity" for "new rate-based generating plant." TUCA 34.051(b)(3). If bid solicitation and negotiation did not result in the resources necessary to meet supply-side needs under the plan, the utility could apply for a certificate of public convenience and necessity for a "utility-owned resource addition" not in the plan. TUCA 34.056.

After completion of the solicitation and negotiation process, the electric utility had to submit a proposed, final integrated resource plan for review by the TPUC. TUCA 34.103. Once a supply-side or demand-side contract was certified by the TPUC as part of the final plan, the TPUC had to treat payments under the contract as a "reasonable and necessary operating expense" for purposes of setting rates and could provide for "monthly recovery" of costs under the contract "as those costs [were] incurred." TUCA 34.104(e).

Ratemaking process: rate changes; test period; rate base; and rate of return.

The TPUC must ensure that the rates of an electric utility are "just and reasonable." TUCA 36.003(a). An electric utility must give notice of a proposed rate change at least 35 days before the effective date of the new rate. TUCA 36.102(a). The TPUC may suspend the rate change for up to 150 days after the date that the rate change would otherwise be effective. Thereafter, the rate may go into effect subject to refund if the electric utility provides a surety bond payable to the TPUC. TUCA 36.108(a)(2) and 36.110(a). Unless a hearing is in progress, if the TPUC fails to make a final determination before expiration of the suspension period, the TPUC is "considered to have approved the [rate] change." TUCA 36.108(c). For good cause shown, the TPUC may allow a rate change that increases revenues by the greater of $100,000 or two and one-half percent to go into effect before the end of the 35-day notice period. TUCA 36.101 and 36.104. In addition, if, on its own motion or on complaint, the TPUC finds that existing rates of a utility are "unreasonable or in violation of law", the TPUC must set just and reasonable rates to be charged in the future. TUCA 36.151(a).

The TPUC must approve rates that provide “overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility’s invested capital used and useful in providing service to the public in excess of the utility’s reasonable and necessary operating expenses.” TUCA 36.051. The TPUC bases its rate determinations on the cost of providing service in a historical test year, adjusted for “known and measurable” changes. 16 TAC 25.231(a). See Suburban Utility Corp. v. Public Utility Commission of Texas, 652 S.W.2d 358, 365 (Tex. 1983) (stating that TPUC may make adjustments to test period data to make them representative of future costs). Further, the TPUC may disallow operating costs that are not reasonable and necessary. For example, the TPUC considered whether a utility’s entering into a contract with a 100 percent take-or-pay payment for capacity (i.e., a requirement to pay all capacity costs whether or not capacity was taken) was prudent. Determining that the utility did not need any of the capacity and could have purchased electricity from other sources without any capacity charges, the TPUC disallowed the capacity charges. Gulf States Utilities, 841 S.W.2d at 471-72. The TPUC may not allow, as an expense or capital costs, any payment to an affiliate unless the TPUC finds, inter alia, that the price is not higher than the price charged by the affiliate to another affiliate or to a nonaffiliate for the same item. TUCA 36.058(c)(2).

In addition, rates must be based on the “original cost, less depreciation, of property used by and useful to the utility in providing service.” TUCA 36.053(a); see also 16 TAC 25.231(c)(2)(A). Generally, plant is not considered used and useful until it is completed. City of El Paso v. Public Utility Commission of Texas, 839 S.W.2d 895, 911-12 (Tex. App. 1992), rev. in part, 883 S.W.2d 179 (Tex. 1994). Consequently, determinations concerning inclusion of plant in rate base are made after plant construction is completed or terminated. However, there are some exceptions to this approach for setting rate base, e.g., for plant not under construction but held for future use and for construction work in progress. See Cities for Fair Utility Rates, 924 S.W.2d at 937-42 (upholding inclusion in rate base of usable portion of costs of uncompleted plant held for future use, where utility had specific plans to use the plant within ten years and where nonusable portion was excluded from rate base and amortized, in order to provide incentive for utility to avoid higher future plant acquisition costs through advance planning and acquisition). CWIP may be included in rate base, but such inclusion is treated as an “exceptional form of rate relief” that the TPUC may allow “only if the utility demonstrates that inclusion is necessary to the utility’s financial integrity.” TUCA 36.054(a). Inclusion of CWIP in the rate base cannot be used for a “major project” to the extent the project has been “inefficiently or imprudently planned or managed.” TUCA 36.054(b). See Texas Utilities Electric Co. v. Public Utility Commission of Texas, 881 S.W.2d 387, 410-411 (Tex. App. 1994), aff’d in relevant part, 935 S.W.2d 109 (Tex. 1996) (upholding inclusion of CWIP in rate base as necessary “to save [utility’s] financial integrity”); and 16 TAC 25.232(c)(2)(D).

With regard to completed plant, the TPUC may consider, in an after-the-fact prudence review proceeding, whether costs associated with the plant were prudent and may exclude plant costs from rate base to the extent imprudence is found. See, e.g., City of El Paso v. Public Utility Commission of Texas, 883 S.W.2d 179, 185-86 (Tex. 1994) (upholding exclusion from rate base of portion of capital investment in nuclear plant due to errors in utility decision-making process in deciding what share of plant to own and whether to maintain that ownership share); and Texas Utilities Electric, 881 S.W.2d at 402-09 (upholding exclusion of portion of capital investment in nuclear plant due to utility imprudence).

With regard to cancelled plant, the TPUC also may consider, in an after-the-fact proceeding, the prudence of plant costs. For example, the TPUC reviewed the cancellation of a nuclear plant and determined the date on which the plant would prudently have been cancelled. The TPUC then allowed a ten-year amortization of the investment in the plant up to that date and disallowed recovery of any subsequent investment. Public Utility Commission of Texas v. Houston Lighting & Power Co., 748 S.W.2d 439,440-42 (Tex. Sup. Ct. 1987) (requiring tax savings from write-off of disallowed investment to be retained by ratepayers).

In setting rates, the TPUC must consider the electric utility's cost of capital, which comprises the actual cost of debt, the actual cost of preferred common stock, and, for common stock, a "fair return on its market value." 16 TAC 25.231(c) (1)(C)(ii)(I). See Central Power and Light Co. v. Public Utility Commission of Texas, 36 S.W.3d 547, 553 (Tex. App. 2000). In establishing a "reasonable return on invested capital" (TUCA 36.52), the TPUC must also consider: "efforts and achievements of the utility in conserving resources" (TUCA 36.052(1)); "quality of the utility's service" (TUCA 36.052(2); "efficiency of the utility's operations" (TUCA 36.052(3)); and "quality of the utility's management" (TUCA 36.052(4)).

Adjustment clauses.

The TPUC can allow rates to include adjustment clauses, but only for certain types of costs. TUCA 36.201 states that, except as provided in TUCA 36.204, the TPUC "may not establish a rate or tariff that authorizes an electric utility to automatically adjust and pass through to the utility's customers a change in the utility's fuel or other costs." Under TUCA 36.204(1), the TPUC may allow "timely recovery" of reasonable purchased power costs. See also TUCA 36.205(b) (stating the TPUC may use "any appropriate method" to adjust purchased power costs already approved by TPUC or FERC); and TUCA 36.206 and 36.207 (allowing, only if necessary for the utility's financial integrity, inclusion of markups for cost of purchasing, financial risk of purchased power obligation, and value added in making power available). Further, TUCA 36.203(a) states that TUCA 36.201 does not prohibit the TPUC "from reviewing and providing for adjustments of a utility's fuel factor" in its rates, which may be done without a hearing.

An electric utility can file a petition to update the charge under the fuel adjustment clause as often as every six months (or in the event of emergency) but must show that the fuel costs and electricity sales on which the proposed fuel charge is based are reasonable estimates. 16 TAC 25.237(a)(2) and (c). The TPUC must issue an order on a fuel-charge petition within 60 days, if no hearing is requested within 30 days of the filing, or 90 days, if a hearing is timely requested. 16 TAC 25.237(e) and (f). Every one to three years, the electric utility must file a petition for reconciliation of fuel expenses and show that the fuel expenses are "reasonable and necessary expenses incurred to provide reliable electric service." 16 TAC 25.236(d)(1)(A). See Texas Utilities Electric, 881 S.W.2d at 411-14 (upholding disallowance of unreasonable fuel costs passed through in fuel adjustment clause).

Retail electric competition: restructuring; and nonbypassable charges for transition and securitization of charges.

In 1999, Texas statute was amended to provide for retail electric competition ("customer choice") starting January 1, 2002 in most of the state. See TUCA 39.001(a) and (b) (legislative findings that electricity production and sale are not a monopoly and that "customer choice" is in the public interest). A later start date for retail electric competition was provided for some areas (TUCA 39.102(c); and TUCA 39.401 and 39.402), and the TPUC was authorized to delay the start date for a power region (i.e., NERC region) "unable to offer fair competition and reliable service to all retail customer classes on January 1, 2002" (TUCA 39.103). As a result of these provisions and the TPUC's exercise of its authority under TUCA 39.103, some portions of the state, (essentially the non-ERCOT portions, e.g., areas served by El Paso Electric, Entergy Gulf States, Inc., Mutual Energy-Southwestern Electric Power Co., and Xcel Energy) continue to be subject to Texas's more traditional regulatory system described above until the commencement of customer choice in those areas. See, e.g., Southwest Power Pool, 2003 WL 23101078 (TPUC May 9, 2003) and 2002 WL 31958980 (TPUC Feb. 1, 2002); and Southeastern Reliability Council, 2001 WL 34061563 (TPUC Dec. 20, 2001). In addition, municipalities and rural electric cooperatives may opt, but are not required, to be covered by retail electric competition.

For areas under retail electric competition, Texas statute exempts companies providing electric generation or retail electric service from the requirements of the more traditional regulatory system by adding exemptions to the definition of "electric utility" for a "retail electric provider" (i.e., a person who sells electricity to retail customers and does not own or operate generation assets (TUCA 31.002(17)) and "a power generation company" (i.e., a person who generates electricity for wholesale sale, does not own transmission or distribution facilities, and does not have a certificated service area (TUCA 31.002(10)). TUCA 31.002(6).

Each electric utility is required to separate its business activities into a power generation company, a retail electric provider, and a transmission and distribution company by

January 1, 2002. This can be done by creating affiliate or nonaffiliate companies or by selling assets to third parties. The TPUC must review each electric utility's plan for business separation. TUCA 39.051. A person "that owns generation facilities may not own transmission or distribution facilities" in Texas, except where necessary to interconnect generation with a transmission or distribution system, a facility not dedicated to public use, or a facility that is not an electric utility. TUCA 39.157(b). A power-generation-company affiliate of a transmission or distribution utility may own generation facilities. Id.; see, e.g., Texas-New Mexico Power Co., 2001 WL 1946229 (TPUC Nov. 9, 2001) (approving separation plan creating separate power generation company, transmission and distribution company, and retail electric provider as subsidiaries of existing holding company); TXU Electric Co., 2001 WL 1946230 (TPUC Nov. 9, 2001) (approving plan creating separate transmission and distribution company and company with unregulated businesses as subsidiaries of intermediate holding company); West Texas Utilities Co., 2001 WL 1898427 at 21 (Oct. 25, 2001), aff'd, City of Abiline v. Public Utility Commission of Texas, 2003 WL 549297 (Tex. App. Feb. 27, 2003) (approving plan creating legally separate power generation company, transmission and distribution company, and retail electric provider); and Reliant Energy, Inc., 2001 WL 1448538 (May 29, 2001) (approving division of utility into two separate corporations, one owning transmission and distribution company and power generation company and other owning retail electric provider with option to buy power generation company). Underpinning Texas' decision to restructure the electric industry is the state legislature's finding that "regulation was no longer warranted, except for regulation of transmission and distribution services and regulation of the recovery of stranded costs." City of Corpus Christi v. Public Utility Commission of Texas, 51 S.W.3d 231, 237 (Tex. 2001).

There are additional, statutory requirements aimed at promoting competition in retail electricity generation and sales. Each electric utility is required to sell, by auction, entitlement to at least 15 percent of the utility's installed generation capacity in Texas. The requirement to sell the entitlements continues until the earlier of five years after commencement of consumer choice or the date that nonaffiliated retail electric providers supply 40 percent of the amount of electricity consumed by residential and small commercial customers in the affiliated transmission and distribution company's certificated service area before the commencement of customer choice. Only entities not affiliated with the electric utility and authorized to sell electricity in Texas may buy the entitlements. TUCA 39.153.

In addition, a power generation company may not own or control (directly or through an affiliate) more than 20 percent of "installed generation capacity located in, or capable of delivering electricity to," a NERC region. TUCA 39.154(a). Excluded from the generation capacity owned or controlled is capacity made available for auction under TUCA 39.153. Included in the NERC region's installed generation capacity is any "potentially marketable electric generation capacity," e.g., any capacity for selfgeneration and any capacity interconnected with a transmission or distribution system. TUCA 39.154(d). An electric utility or power generation company whose share of installed generation capacity exceeds the 20 percent limit must file a market power mitigation plan for meeting the limit. The TPUC must approve, modify, or reject the plan within 180 days but may not require "divestiture." TUCA 39.156(f). The TPUC must monitor companies' shares of installed generation capacity in order to ensure that the percentage limit is not exceeded. TUCA 39.157(c).

Starting January 1, 2002 in most portions of the state, each retail electric customer in the state must have "customer choice" with unregulated retail electric rates, except for customers of rural electric cooperatives and municipal utilities that do not opt for "customer choice." TUCA 39.102(a). An affiliated retail electric provider of an electric utility serving a retail customer on December 31, 2001 may continue to serve that customer until the customer chooses a different provider. TUCA 39.102(b). During the period 2002-2006, an affiliated retail electric provider must offer, to residential and small commercial customers of its affiliated transmission and distribution company, rates (referred to as "price to beat") that are 6 percent less than the rates as of January 1, 1999. TUCA 39.202(a).

Texas statute establishes a mechanism for electric utilities to recover, through nonbypassable charges, stranded costs that result from deregulation of retail electric service. Specifically, an electric utility "is allowed to recover all of its net, verifiable, nonmitigable stranded costs incurred in purchasing power and providing electric generation service." TUCA 39.252(a). See City of Corpus Christi , 51 S.W.3d 231, 241-46 (upholding constitutionality of allowing recovery of stranded costs through transition charges). "Stranded costs" are defined as the "positive excess of the net book value of generation assets over the market value of the assets" and certain "deferred debits" (e.g., generation-related regulatory assets). TUCA 39.251(7). Book value is determined as of the earlier of December 31, 2001 or the date on which the market value of generation assets is established using a market-based methodology (under TUCA 39.262(h)). An electric utility using the stranded cost recovery mechanism must take action to reduce the amount of such costs. TUCA 39.254. An electric utility with no stranded costs must use revenues in excess of costs for capital expenditures to improve or expand transmission or distribution or to improve air quality. TUCA 39.255(a).

By April 1, 2000, each electric utility must submit rates for transmission and distribution service. In particular, the electric utility must develop a nonbypassable delivery charge that is the sum of: a transmission and distribution charge based on a "forecasted 2002 test year" (TUCA 39.201(b)(1)); a "system benefit fund fee" (TUCA 39.201(b)(2)); and an "expected competition transition charge" reflecting stranded costs projected as of December 31, 2001 (TUCA 39.201(b)(3)). The TPUC will determine the period over which stranded costs may be recovered. In order to recover stranded costs, the electric utility may implement a nonbypassable competition transition charge covering up to 100 percent of estimated stranded costs, may implement a transition charge under a “financing order” of the TPUC that allows the utility to “securitize” up to 75 percent of estimated stranded costs and 100 percent of regulatory assets, or may implement a combination of these approaches. TUCA 39.201(i). Recovery of an electric utility’s stranded costs will come from all existing or future retail customers in the company’s certificated service area as of May 1, 1999. Moreover, if a customer has new (i.e., post 1999) on-site generation greater than 10 MW, available without the use of the electric utility’s transmission or distribution facilities, and from which the customer starts taking electricity that “materially reduces” its purchase of electricity, a competitive transition charge will be paid by the customer based on the output of the on-site generation. TUCA 39.252(b)(2). A “material reduction” in electricity purchases is defined as a reduction of 12.5 percent or more. 16 TAC 25.345(i)(4). There is an exception if a customer’s load was served by a fully operational qualifying facility before September 1, 2001. In that case, the charge will only be imposed in connection with services actually provided by the transmission and distribution utility. TUCA 39.262(k).

After January 10, 2004, the affiliated power generation company, transmission and distribution utility, and retail electric provider must jointly file final stranded costs and reconcile these costs with the estimated stranded costs used to set the competitive transition charge. TUCA 39.262(c). Based on this filing the TPUC will review the stranded cost estimate and make adjustments to reflect the final costs. The companies will not be permitted to over-recover stranded costs. TUCA 39.262(a). To the extent the estimated costs exceed the final costs, the TPUC may reduce the company’s cost recovery to reflect the difference, e.g., by reducing the competition transition charge to the extent that the costs are not included in a securitized transition charge or reducing the transmission and distribution utility’s rates. TUCA 39.201(l) and 39.262(g). To the extent estimated costs are less than the final costs, the TPUC may increase the nonbypassable delivery charge or extend the period over which it is applied, and the company may securitize the remaining costs. TUCA 39.201(l) and 39.262(c) and (g).

As noted above, Texas statute establishes procedures under which an electric utility may securitize its stranded cost recovery by selling transition bonds supported by such recovery. At the request of an electric utility, the TPUC must issue a “financing order” if the TPUC finds that total revenues to be collected under the financing order are less than the revenue requirement recovered over the remaining life of the stranded assets “using conventional financing methods.” TUCA 39.303(a). The financing order must approve a “transition charge” for stranded costs and regulatory assets that is recoverable in the same manner as the “competitive transition charge” (TUCA 39.303(c)) over a period not exceeding 15 years (TUCA 39.303(b)) and that is “nonbypassable” (TUCA 39.306). There are streamlined and expedited judicial appeal procedures applicable to TPUC financial orders: such orders must be appealed within 15 days to a specified Texas district court, and that court’s decision must be appealed within 15 days to the Texas Supreme Court. TUCA 39.303(f).

Texas has issued a number of financing orders. See, e.g., TXU Electric Co., 1999 WL 33592527 (TPUC Dec. 21, 1999), rev. in part, TXU Electric Co. v. Texas Public Utility Commission, 51 S.W.3d 275 (Tex. 2001); Central Power Light Co., 2000 WL 33529579 (TPUC Mar. 27, 2000); and Reliant Energy Inc., 2000 WL 33529581 (TPUC Jun. 1, 2000) (financing orders approving issuance of transition bonds by wholly owned special purpose entity, imposing transition charges for life of bonds on all existing retail customers of utility as of May 1, 1999 and all future retail customers located in certified service area (including certain customers with new on-site generation), and requiring utility, retail electric providers, and transmission and distribution providers to collect transition charges for special purpose entity). Each financing order states that it is "irrevocable," "final," "not subject to rehearing," and "not subject to review or appeal" except under the streamlined and expedited appeal procedures, and some also state that the order is "binding" on "any successor to the Commission." See, e.g., Central Power Light, 2000 WL 33529579 at 13, 22, and 27. See also TXU Electric Co., 2002 WL 32077783 at 4 (Jun. 20, 2002) (approving issuance of transition bonds as part of settlement).

Once the financing order and the authorized transition charge become final, they are thereafter "irrevocable and not subject to reduction, impairment, or adjustment by further action" of the TPUC, except for an annual true-up. TUCA 39.303(d). Under TUCA 39.307, the TPUC must conduct at least annually a true-up proceeding to correct for any over- or under-collection of the transition charge and to ensure recovery of amounts sufficient to provide timely payments of debt service and other required charges in connection with the transition bonds. But see TXU Electric, 2002 WL 32077783 (holding that true-up proceeding is not required for utility that agreed not to recover any non-regulatory asset stranded costs or other costs otherwise subject to annual true-up).

There is also a series of provisions to ensure that the transition charges are dedicated, and used, to service the transition bonds. For example, the rights and interests of the electric utility under the financing order are "only a contract right" until they are transferred or pledged in connection with the issuance of transition bonds. TUCA 39.304(a). At that time, they become "transition property," i.e., "a present property right for purposes of contracts concerning the sale or pledge of property, even though the imposition and collection of transition charges depends on further acts of the utility or others." TUCA 39.304(b). All revenues from transition charges constitute "proceeds only of the transition property." TUCA 39.304(c). Further, the interest in transition property and the revenues from such property are "not subject to setoff, counterclaim, surcharge, or defense by the electric utility or any other person or in connection with the bankruptcy of the electric utility or any other entity." TUCA 39.305. Moreover, an agreement transferring transition property and stating that the transfer is "a sale or other absolute transfer" means that the transaction is "a true sale" and "not a secured transaction and that title, legal and equitable, has passed to the entity to which the transition property is transferred." TUCA 39.308. In addition, "a valid and enforceable lien and security interest in transition property" is created only by a financing order and a security agreement in connection with the issuance of transition bonds. TUCA 39.309(b). The lien and security interest attaches upon receipt of value for the bonds, is "continuously perfected" upon the filing of a notice with the Texas Secretary of State, has priority in the order of filing, and takes "precedence over any subsequent judicial or other lien creditor." Id. Finally, Texas pledges not to "take or permit any action that would impair the value of transition property" or to reduce, alter, or impair the transition charge (except for true-up under TUCA 39.307) until the transition bonds are paid in full. TUCA 39.310.

Texas statute provides for an additional nonbypassable charge to retail customers for cost associated with nuclear decommissioning. Those costs "continue to be subject to cost of service rate regulation." TUCA 39.205. A nonbypassable charge is also authorized for the system benefit fund, which may be used only for low-income electric customer assistance, customer education, or school funding losses due to electric restructuring. TUCA 39.903(e). Texas statute does not appear to currently authorize nonbypassable wires charges for any other types of cost.

Retail electric competition: provider of last resort.

The TPUC must designate retail electric providers in customer choice areas as "providers of last resort." TUCA 39.106(a). The provider of last resort must offer, to any requesting customers in its designated area, a "standard retail service package" at a fixed, nondiscountable rate approved by the TPUC. TUCA 39.106(b) and (c). The TPUC must establish procedures and criteria for designating providers of last resort. TUCA 39.106(e). If no retail electric provider applies to be the provider of last resort for a given area on reasonable terms and conditions, the TPUC may require a retail electric provider to take on that function. TUCA 39.106(f). See, e.g., Residential and Small Nonresidential Customers, 2001 WL 34063712 (TPUC Dec. 7, 2001) (approving appointment of providers of last resort, in lieu of failed bidding process, and providing for review and adjustment of provider-of-last-resort rates to ensure there is neither windfall nor net financial loss). Under recently amended regulations, the TPUC will designate providers of last resort through competitive bidding. The TPUC will solicit bids for two-year terms. However, if no eligible bids are received, then the TPUC will select the provider of last resort by lottery. 16 TAC 25.43(g)(2); see Provider of Last Resort Service, 220 PUR4th 1 at 12, 2002 WL 31045264 (Aug. 23, 2002) (explaining that provider-of-last-resort service is a "transitory service that serves as a bridge to alternative offerings in the marketplace" and that providers of last resort should be competitively selected with provider-of-last-resort rates reflecting the costs and risk of the service and not subsidized by users of other services).

As noted above, a provider of last resort must offer a standard retail electric service package with a rate approved by the TPUC. See Residential and Small Nonresidential, 2001 WL 1834071 at 5 (TPUC Aug. 13, 2001) (setting criteria for appointing provider of last resort and holding TPUC has authority to approve reasonable provider-of-last-resort rate even if no rate is included in proposed standard package). The standard package must include "basic firm service" (16 TAC 25.43(d)(3)), i.e., service that is "not subject to interruption for economic reasons" (16 TAC 25.43(c)(1)). If a customer of another retail electric provider does not receive service by such provider, then the provider of last resort must offer the customer the standard retail electric service package "with no interruption in service to any customer." TUCA 39.106(g). The provider of last resort is responsible for obtaining the resources and services "needed to serve" the customers for which it is responsible. 16 TAC 25.43(n)(4). After its term as the provider of last resort ends, the company may continue to provide retail electric service to such customers who do not choose another provider. 16 TAC 25.43(o)(3)(A).

Special provisions for natural-gas-fired electricity generation and renewable-energy electricity generation.

Texas statute expresses a general preference for natural-gas-fired electric generation. TUCA 39.9044(a) states that it is the intent of the Texas legislature that 50 percent of the generating capacity installed after January 1, 2000 use natural gas. The TPUC is required to establish a program to encourage use of natural gas produced in Texas as "the preferential fuel." Id. In response to this mandate, the TPUC established a program under which a natural gas energy credit is granted for each megawatt of new (i.e., post-January 1, 2000) capacity fueled by natural gas and each power generation company, municipal utility, and rural electric cooperative must hold natural gas energy credits in an amount not less than its new non-gas-fired generating capacity (except for renewable energy projects). 16 TAC 25.172(d). Natural gas energy credits may be traded. 16 TAC 25.172(f). The TPUC will activate the program based on a determination that within three years new capacity fueled "primarily" by natural gas "may fall below 55 percent of all new generating capacity." 16 TAC 25.172(e). The TPUC may accelerate or delay the program if such action is "in the public interest." Id.

Texas statute also sets statewide goals for the use of renewal energy for generation of electricity. The TPCU is required to issue regulations to ensure that an additional 2,000 megawatts of renewable-energy electricity generating capacity is installed in Texas by 2009. TUCA 39.904(a); see 16 TAC 25.173(a). Under the TPUC's implementing regulations, the requirement for new renewable-energy generating capacity applies to competitive retailers, and the amount of required new renewable energy resources increases each year. This annual requirement is allocated among the competitive retailers based on, inter alia, their retail sales. 16 TAC 25.173(h). Renewable energy resource credits are awarded for generation from new renewable energy facilities (i.e, those placed in service on or after September 1, 1999) if, inter alia, their above-market costs are not included in utility rates. 16 TAC 25.173(e)(2). These credits have a three-year life and may be traded or transferred. Each year, each competitive retailer must surrender enough credits to equal its share of the requirement for new renewable-energy resources. 16 TAC 25.173(k)(4).

In contrast with the more traditional electric industry regulatory systems in Indiana, Kentucky, and New Mexico but like the competitive system in Ohio, retail electric competition in Texas generally puts the full risk of new electricity generating plant on investors and makes investors' recovery of costs subject to the operation of the electricity market. In general, this approach is inconsistent with the provision of an assured stream of revenues for new IGCC plants under the 3Party Covenant. See Sections 8.3, 9.3, and 9.4.

8.3. Effect on allocation of electricity generation investment risk.

The approach adopted by a state toward utility regulation has a significant effect on the allocation of investment risk of new electricity generating projects. In particular, for the reasons discussed in Section 7.2 above, the approach in states using more traditional utility regulation tends to put more of the construction, operating, and market risk on ratepayers and require ratepayers to bear such risk earlier, as compared to more competitive approaches to retail electric generation and sale.

As discussed in Section 8.11 above, Indiana has adopted a series of special provisions that modify traditional ratemaking in order to provide for additional sharing of the risk of new electricity generating plant (i.e., a "facility for the generation of electricity" (IC 8-1-8.5-2 through 8-1-8.5-6.5)), "clean coal technology" (IC 8-1-8.7-3 through 8-1-8.7-9), "clean coal and energy projects" (IC 8-1-8.8-11), and "new energy generating facilities" (IC 8-1-8.8-12)) between investors and ratepayers. Under these provisions, the IURC: reviews and certifies proposed new electricity generating plant and clean coal technology; allows for recovery of return on capital for IURC-approved construction work in progress prior to completion of the new plant; provides an assured revenue stream for recovery of IURC-approved capital investment and associated return on capital if the plant is not completed; and provides an assured revenue stream for ongoing recovery of all of the IURC-approved capital investment, return on capital, and operating costs if the plant is completed and operational. Recovery of costs can be through an adjustment clause.

As discussed in Section 8.12 above, Kentucky also has provisions for sharing the risk of new electricity generating plant between investors and ratepayers. However, the Kentucky provisions seem to cover a smaller portion of a new plant, and establish less elaborate procedures providing more rapid but less certain cost recovery, than the Indiana provisions. Kentucky provides for ongoing recovery through an adjustment clause of costs of "complying" with environmental requirements (KRSA 278.183) (e.g., capital investment in, and associated return on capital for, emission controls), as well as costs of fuel and purchased power. Recovery of return on capital can commence during construction.

As discussed in Section 8.13 above, in contrast with Indiana and Kentucky, New Mexico does not have any special statutory provisions aimed at providing a sharing of risk of new electricity generating plant between investors and ratepayers. However, some current policies of the NMPRC affect the imposition of risk.

In particular, the NMPRC allows inclusion of construction work in progress in the rate base for new electricity generating plant, which puts some risk on ratepayers, but the inclusion of CWIP is treated as extraordinary rate relief. CWIP is included in the rate base (and return on capital is reflected in rates) only to the extent a utility demonstrates: the reasonableness of the project; use of the least cost method for financing the project; and extensive financial hardship and inability to finance without inclusion of CWIP in the rate base. This apparently means that the NMPRC will consider the prudence of ongoing construction and financing in the context of considering the CWIP issue, as well as later in the context of setting rates once the plant is completed and operating.

Another NMPRC policy affecting the sharing of the risk of new electricity generating plant is the NMPRC's approach concerning excess capacity. The NMPRC does not strictly apply a "used and useful" criterion in determining what plant to include in a utility's rate base for purposes of setting rates. Instead, the NMPRC considers both the "used and useful" criterion and the financial health of the utility and determines what is a "fair" result, which generally involves a sharing of risks and thus costs between ratepayers and investors. However, this approach has been applied to electricity generating plants that were operating, not to cancelled plants.

It is not clear whether, or to what extent, NMPRC policy would allow for sharing the costs of cancelled plant between ratepayers and investors and whether construction work in progress allowed in the rate base for cancelled plant would have to be credited back to ratepayers. The NMPRC has stated that, when it finds that utility plant is used and useful and determines what portion of the capital investment is included in rate base, the NMPRC retains the right in the future to find that the plant is no longer used and useful and therefore to disallow some of the capital investment that is currently allowed in rate base. This approach to disallowance of costs of <u>completed, operating</u> plant raises a significant question whether the NMPRC will allow ratepayers to bear some, or any, risk and thus costs of <u>cancelled</u> plant.

Finally, in contrast with Indiana and Kentucky, New Mexico has a statutory provision interpreted as prohibiting the use of adjustment clauses to recover the full panoply of a utility's plant costs (i.e., capital investment, return on capital, and operating costs), as distinguished from an adjustment clause covering only fuel and purchased power costs. This provision does not seem to prevent adjustment-clause recovery of non-fuel plant costs if a utility purchases electricity from a plant owned by a third party. In that case, all of the third party's plant costs apparently may be characterized as purchased power costs for the utility and recovered by the utility through an adjustment clause. However, reflecting past problems with the use of adjustment clauses, NMPRC regulations limit the use of adjustment clauses for fuel and purchased power costs to cases where such costs fluctuate significantly. Despite the NMPRC's authority to approve fuel and purchased power adjustment clauses, the NMPRC has, for at least one utility, required discontinuation of such adjustment clauses on the grounds that such costs were no longer escalating rapidly and incentives for cost minimization were being reduced. The inability to use an adjustment clause to recover some or all plant costs generally puts more of the risk of recovering such costs on investors.

In Ohio and Texas, one result of utility deregulation legislation is generally to allocate the risk of electricity generating plant to investors, rather than to ratepayers, for companies subject to retail competition. Costs of electricity generating plant are generally to be recovered through rates determined by the electricity market, rather than through cost-based rates determined and imposed by the state PUC. As a result, the risk of cancelled or poorly operating plant, increased plant costs, reduced electricity demand, and declining market electricity prices is generally borne by investors.

However, as discussed in Section 8.2 above, in Ohio and Texas, certain types of plant costs can be recovered through nonbypassable charges set by the state PUC based on costs and paid by all retail customers based generally on their use of the distribution system. In particular, with regard to existing electricity generating plants (i.e., plants as of 2000 in Ohio and as of 2001 in Texas), the portion of capital investment, return on capital, and operating costs that was incurred and deferred for later recovery under the more traditional regulatory system in place before deregulation, but is unlikely to be recovered through market electricity prices, is passed through in nonbypassable wires charges. Depending on the amounts included in the charges, the use of nonbypassable charges can put a portion of the market risk of such existing electricity generating plant on ratepayers.

It should be noted that, if nonbypassable charges can also be used to recover costs of electricity generating plant (whether existing or new) used for provider-of-last-resort service, some construction, operating, and market risk of new plant will be put on ratepayers. In Ohio, each distribution utility must make available, with no time limit, provider-of-last-resort service in its service area, and nonbypassable charges are used to recover certain provider-of-last-resort costs. It is unclear whether or to what extent plant costs (or plant costs reflected in purchased power costs under long-term purchase agreements) will be treated as provider-of-last-resort costs in Ohio. In contrast, in Texas, providers of last resort have two-year terms and are determined through a competitive bidding process or, in the absence of bids, a lottery. Since the TPUC prefers competitive designation of providers of last resort with provider-of-last-resort rates that reflect the costs of provider-of-last-resort service and that are not subsidized by other services, it seems questionable that the TPUC will allow recovery of any provider-of-last-resort costs in nonbypassable charges. Moreover, given the limited term for providers of last resort in Texas, there is a significant question whether plant costs (or plant costs reflected in purchased power costs under long-term purchase agreements) will be treated as provider-of-last-resort costs.

9.0. MODEL REGULATORY MECHANISM FOR REVIEW, APPROVAL, AND RECOVERY OF IGCC PROJECT COSTS.

The focus of this section is the model regulatory mechanism for review, approval, and recovery of IGCC project costs. The purpose of the model regulatory mechanism is to implement the 3Party Covenant discussed in Section 4.0 above for all three categories of IGCC plants discussed in this paper: i.e., new IGCC plants located on greenfield sites; new IGCC plants located on the sites of, and replacing, existing pulverized coal plants; and new gasification islands and other equipment added to, and refueling, existing natural gas combined cycle electricity generation equipment. However, before a model regulatory mechanism and its application can be discussed, it is necessary to describe the circumstances (i.e., project scenarios) under which a new IGCC plant may be financed, owned, and operated because they are likely to affect the regulatory requirements applicable to the project. Section 9.1 describes six project scenarios. Section 9.2 describes the model regulatory mechanism for state PUCs. Section 9.3 discusses the application of the IGCC adjustment clauses, a major component of the model regulatory mechanism, in the states (i.e., Indiana, Kentucky, New Mexico, Ohio, and Texas) whose regulatory systems are discussed in Section 8 above. Section 9.4 summarizes the state statutory changes that seem to be necessary in order for the model regulatory mechanism to be applied in those states. Finally, Section 9.5 addresses the role of the FERC and how that role affects this application.

9.1. Project scenarios for financing, ownership, and operation of new IGCC plants.

There are several scenarios under which a new IGCC plant may be financed, owned, and operated. The way in which financing, ownership, and operation are structured for a specific IGCC project is likely to affect the regulatory requirements applicable to that project.[174]

This is because the project scenario for financing, ownership, and operation will likely determine which utility regulatory commissions or other ratemaking authorities have jurisdiction over the rates charged to customers of the project. Certain factors, which are reflected in the project scenario, are dispositive of the question of rate jurisdiction. One

[174] The structuring of financing, ownership, and operation of a new IGCC plant may also have implications under the Public Utility Holding Company Act (PUHCA) that may need to be taken into account. Except for the following example, those implications are not addressed in this paper. A registered holding company subject to PUHCA must notify the Securities and Exchange Commission (SEC) about proposed issuances or sales of securities. The SEC may bar such notification from taking effect if certain requirements are not met. The SEC generally requires, inter alia, maintenance of a 30 percent minimum common equity share of a holding company's consolidated capital structure. See Allegheny Energy, Inc., SEC Rel. 35-27701, 2003 SEC LEXIS 1704 (July 23, 2003). This does not bar qualification under the 3Party Covenant, which envisions 80 percent debt financing for each IGCC plant, because this minimum common equity percentage requirement does not apply to individual projects financed by an entity in a holding company system. Moreover, the 30 percent minimum common equity requirement may well be lower than the level that is necessary, as a practical matter, for the holding company to obtain conventional financing.

critical factor is whether the electricity generated by the new IGCC plant will be sold directly to retail customers (i.e., residential, commercial, and industrial end-users of electricity) or whether some or all of the electricity will be sold directly to wholesale entities that will in turn resell the electricity, ultimately to retail customers. As discussed in Section 7.11 above, state PUCs generally have jurisdiction over retail sales, while the FERC generally has jurisdiction over sales for resale. Further, once the FERC approves as just and reasonable the wholesale rates reflecting the costs for the IGCC plant, the ability of a state PUC (or other ratemaking authority with jurisdiction over the pass-through of such costs by the wholesale purchaser to retail customers) to review those costs is limited.

Another critical factor is whether a municipal utility or rural electric cooperative is involved in the IGCC project. As noted above, municipal utilities generally are not subject to state PUC jurisdiction over their rates, which are instead determined by the municipality. Depending on the state, rural electric cooperatives may or may not be subject to state PUC rate jurisdiction. As noted above, the FERC lacks jurisdiction over rural electric cooperatives with federal financing and municipal utilities. This section describes several -- but certainly not all -- potential project scenarios for a new IGCC plant.[175] These project scenarios are used in the discussions in Sections 9.2 through 9.5 below of the model regulatory mechanism and FERC jurisdiction.

Under one scenario (the "first" project scenario), the new IGCC plant is directly owned by a public utility in a state in order to use all of the plant's generation to serve the utility's retail customers in that state. (Retail customers served directly by a utility are herein referred to as "direct" retail customers of the IGCC plant.) In this scenario, the state PUC has exclusive jurisdiction over the rates for the plant because there is no sale for resale of electricity generated by the plant and no municipal utility or rural electric cooperative involved. This scenario can apply under a more traditional approach to utility regulation found in Indiana, Kentucky, and New Mexico, where a utility may, of course, own a new IGCC plant and sell the output to retail customers. (Similarly, a utility may lease a new IGCC plant from a third party that constructs and owns the plant and then operate the plant and use the entire output to serve the utility's retail customers.) The applicability of this scenario under a competitive approach to utility regulation may vary from state to state. Specifically, Ohio statute is not entirely clear but does not appear to bar a utility distribution company from owning (or leasing) electricity generating facilities. Electric utilities in Ohio are required to implement a "corporate separation plan" that, inter alia, includes the provision of competitive retail electric service (retail generation and sale) through a "fully separated affiliate"(ORCA 4928.17(A)(1)), and thus there must be a separation of the business of generation and sale from the business of

[175] For example, in order to simplify the analysis, all of the scenarios assume that any retail sales and wholesale sales involving power from the IGCC plant take place in the same state in which the IGCC plant is located. Issues concerning potentially inconsistent rate treatment among states, arising from the involvement of multiple states, are not addressed in this paper and may warrant further research.

transmission and distribution. However, there seems to be no statutory bar to a single company owning facilities both for generation and for distribution, and Ohio electric utilities have generally retained ownership of their generation facilities. See Section 8.21 above. In contrast, Texas statute not only requires corporate separation of generation, retail sale, and transmission and distribution, but also bars a retail electric provider (retail seller) from owning (or leasing) electricity generating plant. See Section 8.22 above. Where the utility (or, where applicable, the utility distribution company) owns the IGCC plant and sells the plant's entire electric output to direct retail customers in the state, the state PUC has sole jurisdiction to review, approve, and allow recovery of the capital investment, return on capital, and operating costs for the plant.

Under another scenario (the "second" project scenario), the new IGCC plant is constructed by a separate company (e.g., an affiliate limited-liability corporation or independent power producer) and leased and operated by the public utility in a state in order to use all of the plant's generation to serve direct retail customers of the plant in the state.[176] In this scenario, there appears to be no sale for resale of the plant's generation. Instead, the lease is likely to be regarded as purely a rental or financing arrangement for the plant if the lessor has no operational control over the plant and the rental payments cover only capital investment and return on capital and are independent of plant availability and the amount of electricity the lessee generates at the plant. Compare United Illuminating Co., 29 FERC ¶ 61,210 at 61,558 (1984) (disclaiming jurisdiction over lease of generating facility where lessor has no operational control and is a business other than generating and selling electricity) with Cleveland Electric Illuminating Co., 76 FERC ¶ 61,156 at 61,925 (1996), reh'g den., 77 FERC ¶ 61,058 (1996) (treating lease of electricity generating plant as sale for resale where utility owner retains operational control).

Further, if the facilities leased include both a new IGCC plant and equipment used in transmission of electricity generated at the plant to the transmission system of lessee, the lease appears to be subject to FERC review under Section 203 of the Federal Power Act. Under Section 203, a public utility cannot sell, lease, or otherwise dispose of its jurisdictional (e.g., transmission) facilities without first obtaining authorization from the FERC. 16 U.S.C. 824b(a). In conducting a Section 203 review of a proposed disposition of generating capacity and related transmission facilities, the FERC considers the effect of the disposition on competition in the generation market (including the potential for affiliate abuse in non-arms-length transactions), wholesale rates, and federal and state regulation. Ameren Energy Generating Co. and Union Electric Co., 103 FERC ¶ 61,128 at 61,410 (2003). It seems that FERC's Section 203 review of the lease may be avoided by limiting the leased facilities exclusively to the IGCC plant itself. See United Illuminating, 29 FERC ¶ 61,270 at 61,558 (holding that sale of generating facility alone

[176] The potential applicability of the second scenario under a more traditional or a competitive approach to utility regulation is same as under the first scenario.

is not subject to FERC jurisdiction); but see Hartford Electric Light Co. v. Federal Power Commission, 131 F.2d 953, 961-62 (2d. Cir. 1942), cert. den., 319 U.S. 741 (1943) (holding that generating facility knowingly used to produce electricity ultimately for resale in interstate commerce is subject to FERC jurisdiction). In any event, it seems unlikely that, given the absence of any sale for resale of electricity under this project scenario, FERC review under Section 203 will result in disapproval of the lease based on the costs of the plant reflected in the lease payments because such costs are reflected solely in retail rates and the Federal Power Act reserves retail sales for state jurisdiction. See id.; and Order No. 592, 61 Fed. Reg. 68595, 68603 (1996), on reconsideration, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (noting that, while most rate issues in a utility merger affect retail customers and are subject to state PUC jurisdiction, FERC will review rate issues as necessary to protect wholesale and transmission customers).

Under another scenario (the "third" project scenario), the IGCC plant is directly owned by a public utility in a state in order to use the plant's generation to serve in the state both direct retail customers of the plant and wholesale customers who contract with the IGCC plant owner in order to use the electricity to serve their own retail customers in the state. (Retail customers served by wholesale customers of the IGCC plant are herein referred to as "indirect" retail customers of the IGCC plant.)[177] According to the FERC, most existing electricity generating plants are used to serve both retail and wholesale customers, and the retail and wholesale portions of sales from a plant can vary over time with market conditions. AEP Power Marketing, Inc., 107 FERC ¶ 61,018 at 61,060 (2004). In this scenario, there are both end-user sales and sales for resale of the plant's generation. There is split rate jurisdiction over the plant in that the state PUC has jurisdiction over the rates for direct retail customers and the FERC has jurisdiction over the rates for wholesale customers (except where the plant is in the ERCOT region of Texas and all sales are within that region). See Section 9.5 below discussing how the FERC is likely to exercise its jurisdiction. Moreover, the state PUC also has jurisdiction (limited by federal pre-emption) over the pass-through of costs in the wholesale rates to the indirect retail customers of the IGCC plant. To the extent the wholesale sales are to non-firm customers (e.g., where electricity in excess of retail customers' demand is sold on the spot wholesale market), the capital investment (and associated return on capital) in the new IGCC plant may be attributed entirely to direct retail customers. This may be based on the assumption that the plant was built to meet their needs and not for the purpose of spot sales. However, to the extent that the wholesale sales are to firm customers, it may be necessary for the state PUC and the FERC to allocate the capital investment (and associated return on capital) in the plant between direct retail and wholesale sales.

[177] The discussion of the potential applicability of the first scenario under a more traditional or a competitive approach to regulation applies to the third scenario as well.

Under another scenario (the “fourth” project scenario), the new IGCC plant is constructed, owned, and operated by another company (e.g., an affiliate or independent power producer) in order to sell all of the plant’s generation to a utility in a state to use the electricity to serve, in the state, indirect retail customers of the IGCC plant. This scenario can apply under either the more traditional approach to utility regulation in Indiana, Kentucky, and New Mexico or the competitive approach in Ohio and Texas. In this scenario, there is a sale for resale. Except where the plant is in the ERCOT region of Texas and all sales are within that region, the rates for sales for resale are subject to FERC jurisdiction. The pass-through of costs to the indirect retail customers of the IGCC plant is subject to state PUC jurisdiction.

The last two scenarios involve rural electric cooperatives with federal financing or municipal utilities. Under one of the scenarios (the “fifth” project scenario) the new IGCC plant is directly owned by one or more rural electric cooperatives with federal financing or municipal utilities in a state in order to use all of the plant’s generation to serve their respective retail customers in that state. In this scenario, there is no FERC jurisdiction both because there is no sale for resale and because the FERC lacks jurisdiction over rural electric cooperatives with federal financing and municipal utilities. If the state PUC also lacks rate jurisdiction over the rural electric cooperatives and municipal utilities involved, rates are set by the local entities with ratemaking authority for the plant owners, e.g., the board for the rural electric cooperative and the municipality for the municipal utility.

Under the last scenario (the “sixth” project scenario), the IGCC plant is constructed, owned, and operated by an independent entity (e.g., a utility or an independent power producer) in order to sell the plant’s generation to one or more rural electric cooperatives with federal financing or municipal utilities in a state for them to use the electricity to service their respective retail customers in the state. In this scenario, there are sales for resale. Consequently, the FERC has rate jurisdiction unless the exception for the ERCOT region of Texas applies. These last two scenarios are not discussed further in this paper and may warrant further research. However, to the extent that a rural electric cooperative or a municipal utility under the fifth and sixth project scenarios is not subject to FERC and state PUC review, the body that determines the rates that are charged the rural electric cooperative’s or municipal utility’s retail customers will need to perform similar functions as the state PUC under the model state PUC regulatory mechanism.

9.2. Model state PUC regulatory mechanism for review, approval, and recovery of costs.

The following is a description of an integrated mechanism -- reflecting an amalgamation and coordination of various state PUC provisions in several states -- that implements the 3Party Covenant by providing an assured revenue stream for new IGCC plant and a sharing of risk among investors, the federal government, and ratepayers. As discussed in Section 4.0 above, the 3Party Covenant comprises the key elements of: private investor provision of equity capital investment in the new IGCC plant; federal guarantee of relatively highly leveraged (i.e., 80 percent of Total Plant Investment), non-recourse debt capital for the new IGCC plant; and state PUC review and provision of an assured revenue stream for IGCC-project-cost recovery. The model regulatory mechanism assumes that the first or second project scenario applies to the new IGCC plant and thus that the state PUC has exclusive rate jurisdiction. However, as discussed in Section 9.5 below, this regulatory mechanism may be applicable to the third and fourth project scenario. The model regulatory mechanism is intended for use in both states with more traditional utility regulation and states with competitive retail electricity generation and sales, but will likely require more extensive legislative changes in states with retail electric competition. See Section 9.4 below.

1. Before any construction begins, the state PUC reviews the company's detailed proposal for the new plant in order to determine whether the plant is in the public convenience and necessity. Determining the public convenience and necessity involves consideration, and may require quantification, by the state PUC of several factors concerning the likely benefits and costs of the proposed IGCC plant. Based on a satisfactory balancing of these factors, the state PUC then issues a certificate of public convenience and necessity for the new plant.

a. Among the factors considered in weighing the benefits and costs of the proposed IGCC plant are: the need for new base-load electricity generation capacity to meet future demand; the need for fuel diversity for electricity generation and which specific fuel or fuels will be used in the new IGCC plant; the projected level, volatility, and reasonableness of costs of capacity and electricity from the new IGCC plant relative to alternative sources of electricity; the acceptability of the technology risk of the proposed IGCC plant; the economic feasibility of the proposed IGCC plant; the benefit to ratepayers of the federal loan guarantee; the effect of the proposed IGCC plant on economic development in the state, particularly any local coal industry; and the air, water and solid waste environmental impacts of the proposed IGCC plant. Analysis of the technology risk includes consideration of: the extent to which a guarantee is provided by the engineering, procurement, and construction contractor (supported by underlying warranties from by equipment vendors) involved in the project; the likely reliability of the plant; and the availability of the Construction and Operating Reserve Fund (which, as discussed in Section 4.32 above, equals 10 percent of the plant's Overnight Capital Cost) and the Line of Credit (which, as discussed in Section 4.33 above, cannot exceed 15 percent of the Overnight Capital Cost and must be matched with additional equity capital equaling 20 percent of the amount drawn) for contingencies.[178] Analyses of projected IGCC project costs, economic feasibility, and federal-loan-guarantee benefits reflect the impact of the 3Party Covenant on cost of capital. Analysis of the effect on local economic development includes consideration of what portion (at least 75 percent, as discussed in

[178] The state PUC may want to require a minimum level of coverage by the EPC guarantee.

Appendix A above) of the heat input for the plant will be from coal and the effect that will have on any local coal industry.[179]

b. As part of its review of the plant proposal and issuance of the certificate, the state PUC establishes the return-on-capital percentage (encompassing interest, preferred stock dividend, and return on common equity) for the project and, as discussed below, approves use of an IGCC fixed-cost adjustment clause and an IGCC variable-cost adjustment clause, for future recovery of incurred project costs as the costs are approved. The state PUC should make the return-on-capital figure (including return on common equity) permanent for the life of the project in order to create an assured revenue stream to support the federal loan guarantee under the 3Party Covenant. Any subsequent reduction in the return on common equity will reduce the cushion for debt service and adversely affect the debt investors' and the federal loan-guarantor's risk.[180]

c. As part of its review of the plant proposal and issuance of the certificate, the state PUC also establishes the depreciation and amortization periods for categories of preconstruction and construction expenditures.

2. After issuance of the certificate and as construction progresses, the state PUC periodically (e.g., semiannually)[181] conducts a prudence review (on an expedited basis) of the portion of the IGCC plant constructed during the preceding review period (e.g., preceding 6 months) and the associated preconstruction and construction expenditures. After each review, the state PUC approves that portion of the IGCC plant construction and costs as appropriate. This type of approach is used in Indiana. See Section 8.11 above. Although Indiana statute allows the company to choose between ongoing periodic review and one-time, after-the-fact review at the end of the project, ongoing review should be required. The ongoing review process better accommodates both: the ratepayers' interest in assurance that costs are prudently incurred, and that any necessary corrective action is taken, at each stage of the project; and the investors' and the federal

[179] However, the state PUC cannot require that the coal come from any particular state. See, e.g. General Motors, 654 N.E.2d at 763-67.

[180] In determining the return-on-capital percentage, the state PUC may want to consider a higher return (e.g., up to three percentage points higher as allowed under Indiana statute) for equity capital invested in new plant, as an incentive for construction of an IGCC plant. See Section 8.11 above. The level of the return on equity and any desire by the state PUC to reserve the ability to revise the return on equity in the future are likely to be the subject of negotiation with potential IGCC-project owners and the federal loan guarantor.

[181] While quarterly review results in more expeditious recovery of costs and more frequent review, semi-annual review may be more practical, and less burdensome, for the state PUC and may facilitate public participation and more thorough review. New Mexico found quarterly review under cost-of-service indexing to be overly burdensome and not conducive to effective regulatory oversight. See Section 8.13 above. New Mexico's experience is not fully applicable here because cost-of-service indexing involved automatic adjustment and regulatory review of all the regulated activities on an entire utility, rather than simply activities related to IGCC projects under the 3Party Covenant. However, New Mexico's experience indicates the importance of establishing a regulatory mechanism that does not impose burdens beyond the resources available to the state PUC. Consequently, the state PUC should be authorized to impose fees on the IGCC-project owner to defray the costs of administering the model regulatory mechanism.

loan-guarantor's interest in the greatest assurance of cost recovery. After issuance of a certificate for the new plant, the company can rely on the certificate and subsequent ongoing review to provide an assured revenue stream for recovery of approved capital investment in the plant and the associated return on capital.

a. As soon as each portion of preconstruction and construction expenditures for the new plant (i.e., construction work in progress) is approved in the ongoing review, the return on capital for the approved preconstruction and construction expenditures becomes recoverable on an ongoing basis through, and is reflected in, the approved IGCC fixed-cost adjustment clause.[182] The calculation of the charge under the IGCC fixed-cost adjustment clause is reviewed (on an expedited basis) on the same periodic basis as the state PUC's ongoing review of the expenditures. Indiana uses this type of coordinated approach to review and recovery of construction work in progress. See Section 8.11 above. Recovery is more assured and more timely if accomplished through an adjustment clause with expedited review, instead of through a general rate case.

i. Assuming that ongoing review is conducted, for example, every six months and that the duration of each periodic review proceeding is limited, for example, to three months, the return on capital will be recovered within three to nine months after incurrence of the associated expenditures. Since most of the return on capital is recovered on an ongoing basis during construction, a much smaller amount will be accrued, added to the total capital investment in the plant, and ultimately recovered through amortization.

ii. A charge is calculated under the IGCC fixed-cost adjustment clause based on: the relevant, approved capital-related costs (e.g., during construction, the return on capital and, after plant completion, the return of and on capital) actually incurred during a review period (e.g., every six months); and, as appropriate, the parameters approved by the state PUC as the basis for allocating return of and on capital among retail classes and individual retail customers. The charge may also need to include provisions to true-up for any over-collection or under-collection of the relevant, approved capital-related costs incurred during the preceding review period.

b. Instead of structuring review and recovery as set forth above in paragraph 2.a, the state PUC can allow ongoing recovery of return on capital through the approved IGCC fixed-cost adjustment clause before approval of the underlying preconstruction and construction expenditures. For example, the IGCC fixed-cost adjustment clause charge can be updated every month or every 3 months while the ongoing review is conducted every 6 months. This type of approach is used in Kentucky

[182] Precedents for this are found in several state statutes. Indiana statute provides recovery (through an adjustment clause) of return on capital for CWIP for clean coal technology, while Kentucky provides for such recovery for costs of environmental compliance for coal combustion. Prior to deregulation, Ohio provided recovery of return on capital for CWIP for pollution control equipment, as did Illinois. See Sections 8.11, 8.12, and 8.21 above.

for recovery of capital investment, return on capital, and operating costs associated with certain emission controls. See Section 8.12 above.

i. If some of the underlying preconstruction and construction expenditures are not approved in the ongoing review, the IGCC fixed-cost adjustment clause charge can be adjusted in order to credit to retail electric customers the excess return on capital that was already recovered. This adjustment is similar to the adjustment made to account for over-collection or under-collection, as discussed above in paragraph 2.a.ii.

ii. Allowing recovery of return on capital to commence through an adjustment clause before approval of the underlying expenditures reduces even further the portion of the return on capital that is recovered during construction and therefore the amount that will be accrued and added to the total capital investment in the plant. However, as discussed below, the federally guaranteed loan will be disbursed, for a given portion of the expenditures, only after review and approval of that portion of the expenditures.

c. As each portion of the preconstruction and construction expenditures is reviewed and approved, future recovery of these costs (including the associated return on capital) cannot be challenged, except in limited circumstances, i.e., fraud, concealment, or failure to complete an operable plant. For example, issues concerning excessive cost, inadequate quality control, or inability of the plant to continue to operate properly cannot be raised. In this way, the state PUC's review and protective approval is updated during and after plant construction. This type of approach is used in Indiana and, coupled with use of adjustment clauses as the recovery mechanism (as discussed below in paragraph 3), provides an assured revenue stream for recovery of preconstruction and construction expenditures and associated return on capital. See Section 8.11 above.

i. Disbursement of the federally guaranteed, non-recourse loan is coordinated with the ongoing review process. As each portion of the preconstruction and construction expenditures is reviewed and approved for recovery through the approved IGCC adjustment clause, the federally guaranteed loan is disbursed for the debt-funded (i.e., 80 percent) share of that portion of the expenditures. Such approval minimizes the likelihood of any call on the federal guarantee. Prior to disbursement of the federally guaranteed loan, the company must finance preconstruction and construction expenditures using company resources or, to the extent available, the federal revolving fund for Pre-development Engineering Loans (as discussed in Appendix A above).

ii. If construction of the new plant is terminated before plant completion or if the plant is never operable, each portion of the preconstruction and construction expenditures that was approved during the ongoing review cannot be challenged and is recoverable. Preconstruction and construction expenditures that were not approved are recoverable only upon a showing that they were necessary and prudent and in the absence of fraud, concealment, or gross mismanagement. However, a limitation on recovery of preconstruction and construction expenditures, whether or not they were approved, is imposed: 10 percent of the capital investment in the plant (i.e., 50 percent of the equity capital), whether or not approved, is not recoverable in the event of failure to complete an operable plant. The debt capital and interest are still fully recoverable. An alternative approach (used in Indiana) is to make up to 100 percent of the total capital investment, and thus of the equity capital portion of that investment, recoverable if the total investment was either approved in ongoing review or is found to be necessary, prudent, and in the absence of fraud, concealment, or gross mismanagement. See Section 8.11 above.

iii. Approved preconstruction and construction expenditures (including associated return on capital not already been recovered through return on construction work in progress) are depreciated or amortized over the appropriate period and will be recovered through the approved IGCC fixed-cost adjustment clause.

3. After completion and commencement of operation of the new IGCC plant, the state PUC periodically (e.g., semiannually) conducts on an expedited basis a prudence review of the plant's operating costs during the preceding review period (e.g., the preceding 6 months). Operating costs comprise operation and maintenance, fuel, and taxes.

a. As soon as the operating costs for each review period (e.g., every six months) are approved in the ongoing review after the commencement of plant operation, the approved operating costs become recoverable on an ongoing basis through, and are reflected in, the approved IGCC variable-cost adjustment clause. A per-kilowatt-hour charge is calculated under the IGCC variable-cost adjustment clause based on the approved operating costs actually incurred during the review period and the estimated kilowatt-hour sales for the next review period. The charge must include provisions to true-up for any over-collection or under-collection of the approved operating costs incurred during the preceding review period due to any difference between estimated kilowatt-hour sales used for recovery of such costs and actual kilowatt-hour sales.

b. Coordinated with the approval and pass-through of operating costs, the depreciation and amortization of the previously approved preconstruction and construction expenditures and the return on capital associated with such expenditures become recoverable on an ongoing basis through, and are reflected in, the approved IGCC fixed-cost adjustment clause. The calculation of charges under the adjustment clauses is reviewed (on an expedited basis) on the same periodic basis as the state PUC's ongoing review of the operating costs.

c. The state PUC must require the IGCC plant owner to segregate the entire revenue stream from the adjustment-clause charges and place such revenues in a separate account that is used only to pay IGCC project costs, including debt amortization and interest.

d. Instead of structuring review and recovery as set forth above in paragraph 3.a, the state PUC can allow ongoing recovery through the approved IGCC variable-cost and fixed cost adjustment clauses before approval of the operating costs. For example, the IGCC variable-cost and fixed-cost adjustment clause charges can be updated every month or every three months while the ongoing review is conducted every six months. The process is analogous to that described above in paragraph 2.b.

4. The state PUC decisions under paragraphs 1 through 3 above must be sufficiently binding in the future to be viewed by investors and the federal government as providing an assured revenue stream that supports the federal loan guarantee under the 3Party Covenant.

a. A state legislature has the authority to adopt provisions making state PUC decisions binding in the future on the state PUC. This is because the legislature has general authority to set electric utility rates itself or to delegate ratemaking (whether more traditional ratemaking or more limited ratemaking under a competitive approach) to a state PUC. The legislature may impose appropriate limitations on such delegation. For example, the New Mexico legislature has the authority to delegate ratemaking authority to the state PUC with limitations deemed appropriate by the legislature because the New Mexico Constitution (art. 11, § 2) provides that the state PUC (i.e., the NMPRC) has "responsibility for regulating public utilities…in such manner as the legislature shall provide." See Mountain States Telephone & Telegraph Co. v. New Mexico State Corporation Commission, 563 P.2d 588, 597 (N.M. 1977) (explaining that now-repealed provision of New Mexico Constitution (art. 11, § 7) directly granted state PUC "plenary" authority to set rates without any statutory limitation and that if, instead, state PUC were "a creature of the Legislature," state PUC's authority would be limited to authority delegated by statute).[183] Unless somehow barred by the state constitution, the limitations imposed by a state legislature can include limitations on the ability of the state PUC to revisit specified determinations (e.g., concerning prudence of ongoing capital expenditures and allowed return on equity). Indiana statute seems to provide this type of limitation with regard to the prudence of clean coal technology construction costs approved by the IURC during ongoing construction review. See Section 8.11 above. In addition, reflecting the apparent ability to bind future commissions, orders issued by the TPUC approving recovery of approved transition costs through non-bypassable wires

[183] Similarly, for states where establishment of the state PUC is not constitutionally based, the state PUC is still created by statute and subject to the limitations in statute. See, e.g., Coalition of Cities for Affordable Utility Rates v. Public Utility Commission of Texas, 798 S.W.2d 560, 564-65 (Tex. Sup. Ct. 1990), cert. den., 499 U.S. 983 (1991) (holding that TPUC was not granted statutory authority to, and so could not, give utility second chance in a proceeding to demonstrate prudence of investment in nuclear plant); and Denton County Electric Cooperative, Inc. v. Public Utility Commission of Texas, 818 S.W.2d 490, 492 (Tex. App. 1991) (holding that administrative agencies are "creatures of statute and have no *inherent* authority" and that TPUC was granted statutory authority to revoke certificates of public convenience and necessity only on specified grounds). See also South Central Bell Telephone Co. v. Utility Regulatory Commission, 637 S.W.2d 649, 652-54 (Ky. 1982) (holding that KPSC was not granted statutory authority, and so could not, reduce rate of return as penalty for inadequate service.)

charges state that each order is binding on successors to the TPUC. See Section 8.22 above.

b. A state legislature seems to have the ability to reduce the likelihood that a future state legislature will take actions that will reverse or interfere with state PUC determinations delegated by the state legislature. Precedent is provided by Texas statutory provisions concerning transition costs that are securitized through issuance of transition bonds. Under Texas statute, the state "pledges" not to take any action that will impair the recovery of approved, securitized transition costs through non-bypassable wires charges (TUCA 309.310), and the right to such recovery becomes "property," which presumably cannot be taken by the state without compensation (TUCA 39.304). See Section 8.22 above.

c. A state legislature seems to have the ability to provide additional protections to ensure that the approved recovery of project costs is not impaired by events such as bankruptcy. See Section 8.22 above (discussing Texas statutory provisions protecting recovery of approved, securitized transition costs from third party claims); and Walter R. Hall II, "Securitization and Stranded Cost Recovery," 25 Energy L.J. 173, 192-99 (discussing provisions in other state statutes to protect recovery of approved, securitized transition costs).[184]

9.3. Imposition of approved IGCC adjustment-clause charges under model state PUC regulatory mechanism.

To support the federal guarantee of debt capital in the IGCC plant under the 3Party Covenant, the approved IGCC adjustment-clause charges under the model state PUC regulatory mechanism under the first and second project scenarios must be imposed in a way that provides an assured revenue stream. The revenue stream must recover the approved capital investment, associated return on capital, and operating costs.

In states with a more traditional regulatory approach (e.g., Indiana, Kentucky, and New Mexico), this means that charges under the approved IGCC fixed-cost adjustment clause should be imposed on all retail customers in the service area of the utility that owns or leases the new IGCC plant. The charges under the IGCC variable-cost adjustment clause should be imposed only on retail customers that actually purchase electricity from the utility.

In states with competitive retail electricity generation and sale, an assured revenue stream for recovery of capital investment and return on capital will be provided if charges under the approved IGCC fixed-cost adjustment clause are imposed, as a nonbypassable wires charge, on all retail customers in the service area in which the company that owns or

[184] The provisions needed to protect recovery of approved IGCC project costs throughout the life of the plant against such events as the owner's bankruptcy are not discussed in detail in this paper and may warrant further research.

leases the new IGCC plant is the provider of last resort. The charges under the approved IGCC variable-cost adjustment clause should be imposed on only the retail customers that actually purchase electricity from the company.[185]

In Ohio and Texas, retail customers that do not choose a retail electric provider or whose retail electric provider fails to provide sufficient electricity to meet their firm demand are required to be served by a provider of last resort. In Ohio, the distribution utility is the provider of last resort, while, in Texas, the provider of last resort is chosen for two-year terms through a bidding process or, in the absence of reasonable bids, through lottery conducted by the TPUC. The provider of last resort is required to have sufficient capacity and electricity to provide firm electric service to these retail customers. The use of the IGCC plant as base load plant necessary for firm electric service may provide a rationale (at least in Ohio) for imposing the approved IGCC fixed-cost adjustment clause on all retail customers in the service area. See Section 8.3 above.

However, with competitive electricity generation and sales, some of the retail customers in the service area of the company that owns or leases the IGCC plant will be buying electricity from other suppliers. In these circumstances, one possible approach may be to impose the IGCC fixed-cost adjustment clause as a nonbypassable wires charge on all retail customers in the service area, but to give each alternative supplier with retail customers in the service area an entitlement to a share of the IGCC plant's capacity, perhaps in proportion to such supplier's retail-customer load in the service area.[186] This entitlement gives the alternate supplier the right to elect to pay operating costs for, and take, electricity from the IGCC plant. Imposition of the nonbypassable wires charge on all retail customers appears to reduce any competitive disadvantage to the company that owns or leases the IGCC plant. Giving the alternative suppliers pro-rata entitlement to the IGCC plant capacity appears to reduce any competitive disadvantage to the alternative suppliers or unfairness to their retail customers. However, it should be noted that the right of the alternate supplier to call on electricity from the new IGCC plant seems to limit, to some extent, the ability of the company that owns or leases the IGCC plant to rely on the plant to meet provider-of-last-resort obligations.

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[185] To the extent the model regulatory mechanism is applicable under the third project scenario as discussed in Section 9.5 below, the IGCC fixed-cost adjustment clause should also be imposed on all retail customers in the service area of the company with a firm power purchase contract with the IGCC plant (under more traditional regulation) or in the service area where such company is the provider of last resort (under retail electric competition). To the extent the mechanism applies to the fourth project scenario, the IGCC fixed-cost adjustment clause should be imposed only on such retail customers of such company. Under either of these scenarios, the IGCC variable-cost adjustment clause should be imposed on retail customers that actually purchase electricity from such company.

[186] There probably should be a procedure for adjusting each retail electric provider's share of the IGCC plant capacity over time. This may be accomplished by coordinating the adjustment with the periodic (e.g., semiannual) ongoing review conducted by the state PUC starting with the commencement of construction of the plant and continuing once the plant begins operation. Each retail electric provider's entitlement may be set for the next review period (e.g., the next 6 months) based on that provider's share of retail electricity demand in the service area during the previous review period.

It should also be noted that the provision to alternative suppliers of any entitlement to the IGCC plant capacity seems likely to be viewed as sales for resale, i.e., sales to such alternative suppliers for resale to their retail customers. If that view prevails, then the provision of such entitlement will be subject to FERC jurisdiction (unless the exception for plants in the ERCOT region of Texas applies). See Section 9.5 below (discussing FERC review of rates for sales for resale).

9.4. State statutory changes necessary for use of model state PUC regulatory mechanism.

An effort was made to design the above-described model state PUC regulatory mechanism in a way that minimizes -- to the extent consistent with the requirements of the 3Party Covenant -- the scope and complexity of state statutory changes necessary for implementation. Not surprisingly, the statutory changes that may be necessary will vary from state to state. Below are discussed the statutory changes that may be needed under the first and second project scenarios in the five sample states: Indiana, Kentucky, New Mexico, Ohio, and Texas.

The smallest amount of statutory changes seems to be necessary in Indiana. As discussed in Sections 8.11 and 8.3 above, Indiana already has in place a series of special provisions authorizing -- for application to new facilities "for the generation of electricity," "clean coal technology," "clean coal and energy projects," and "new energy generating facilities" -- the key elements in the model state PUC regulatory mechanism. In fact, the model mechanism was, to a large extent, developed based on a review of Indiana law. The key elements of the model mechanism include: upfront review of, and issuance of a certificate of public convenience and necessity for, each IGCC project; ongoing prudence review of project preconstruction and construction costs from commencement of construction through plant start-up and assurance of future, adjustment-clause pass-through of approved capital expenditures and associated return on capital; ongoing pass-through, during construction, of return on capital for approved capital investments; ongoing prudence review of project operating costs; and ongoing pass-through of depreciation and amortization of approved capital investments, associated return on capital, and operating costs. The operative terms (quoted above) for Indiana's special provisions seem clearly to cover an entire, new IGCC plant. However, it may be desirable for the state legislature to expressly authorize the IURC to set upfront a fixed return on equity for a new IGCC plant covered by the 3Party Covenant. Approval of a fixed return on equity may be considered inconsistent with the IURC's obligation under Indiana statute to review existing rates to determine whether they are just and reasonable and, when it determines that they are, to set prospectively new rates. In addition, the state legislature should ensure that the IURC is authorized to impose fees on IGCC-project owners to defray the costs of administering the model regulatory mechanism.

More statutory changes seem to be necessary in order to adopt the model state PUC regulatory mechanism in Kentucky. As discussed in Sections 8.12 and 8.3 above, Kentucky has in place less elaborate procedures than Indiana, but provides for ongoing review, approval, and recovery of capital investment, associated return on capital (including during construction), and operating costs for "complying" with environmental requirements. Since interpretation of the operative term -- "complying" with environmental requirements -- to cover an entire IGCC plant may be problematic, it seems desirable for the state legislature to adopt expressly that interpretation. In addition, it seems desirable for the state legislature to adopt more detailed provisions concerning: upfront review of each new IGCC plant and issuance of a certificate of public convenience and necessity; ongoing prudence review of project preconstruction and construction costs and operating costs; and, in particular, assurance of future, adjustment-clause pass-through of approved depreciation and amortization of capital expenditures and associated return on capital (including cases of cancelled or inoperable plant) and of approved operating costs. Once the capital expenditures, associated return on capital, and operating costs are approved, they should be recoverable with no further review, except in the event of fraud, concealment, or failure to complete an operable plant as discussed in Section 9.2 above. It may also be desirable for the state legislature to expressly authorize the KPSC to set upfront a fixed equity return for a new IGCC plant under the 3Party Covenant, particularly in light of the KPSC's statutory authority to review existing rates and, if they are unjust or unreasonable, prospectively set new rates. In addition, the state legislature should ensure that the KPSC is authorized to impose fees on IGCC-project owners to defray the costs of administering the model regulatory mechanism. These types of statutory changes seem to be consistent with Kentucky's express policy to "foster and encourage use of Kentucky coal by electric utilities." KRSA 278.020(1).

More extensive statutory changes seem to be necessary in order to adopt the model state PUC regulatory mechanism in New Mexico. As discussed in Section 8.13 and 8.3 above, New Mexico does not have provisions like those in Indiana and Kentucky for ongoing review, approval, and recovery of capital expenditures, return on capital, and operating costs for new plant or equipment. On the contrary, the NMPRC conducts after-the-fact review of whether new electricity generating plant is "used and useful" and whether the plant costs were prudently incurred. Moreover, the NMPRC seems to reserve the ability to revisit past "used and useful" determinations and to disallow additional plant costs in the future. Thus, there is a significant question whether the NMPRC will allow recovery of plant costs of uncompleted plant. With regard to inclusion of CWIP in rate base, the NMPRC limits such inclusion to cases of extensive financial hardship. With regard to adjustment clauses, New Mexico statute is interpreted as barring the use of adjustment clauses for costs other than taxes, fuel, and purchased power, and the NMPRC seems to limit strictly the use of even fuel and purchased power adjustment clauses. While these provisions and policies may well be generally appropriate for utility regulation in New Mexico, they impose hurdles to the application of the model regulatory mechanism and the implementation of the 3Party Covenant.

In order for the model regulatory mechanism to be used in New Mexico, legislation seems necessary to set forth reasonably detailed provisions, as discussed in Section 9.2 above and applicable only to IGCC plants under the 3Party Covenant, for: upfront review of each IGCC project and issuance of a certificate of public convenience and necessity; ongoing prudence review of project preconstruction and construction costs and operating costs; and assurance of future, adjustment-clause pass-through of approved depreciation and amortization of capital expenditures and associated return on capital (including cases of cancelled or inoperable plant) and approved operating costs, with return-on-capital recovery starting during construction. It may be desirable for the state legislature also to expressly authorize the NMPRC to set upfront a fixed equity return for such an IGCC plant, particularly in light of the NMPRC's statutory authority to review existing rates.

Restricting these statutory changes to new IGCC plants that the state PUC will approve for coverage under the 3Party Covenant, and will carefully scrutinized on an ongoing basis, seems consistent with policies of the New Mexico legislature and the NMPRC. Specifically, these statutory changes, limited to such IGCC plants, seem to balance the state's express interest in promoting energy self-sufficiency and the state's concern that broadly applicable adjustment-clause procedures may adversely affect incentives for cost minimization and may overburden the NMPRC. The state legislature should address this later concern by ensuring that the NMPRC is authorized to impose fees on IGCC-project owners to defray the costs of administering the model regulatory mechanism. Moreover, these statutory changes are consistent with the NMPRC precedent recognizing that stability in cost recovery can result in new capital investment, reduced cost of capital, and promotion of capital intensive technologies (here, IGCC technology). In considering these changes, New Mexico will, of course, consider other relevant state policies, such as the promotion of renewable-energy generation.

Finally, the most extensive legislative changes seem to be necessary in order to adopt the model state PUC regulatory mechanism in Ohio and Texas. As discussed above, one result of deregulation legislation in those states is generally to require that: investors bear the full risk of new electricity generating plant; and the costs of such plant be recovered through rates determined by the electricity market, rather than through cost-based rates reviewed and approved by the state PUC. In order to allow for the additional ratepayer risk and the assured revenue stream that are necessary to implement the 3Party Covenant, legislation creating an exception for new IGCC plants under the 3Party Covenant from the general deregulatory regime in Ohio and Texas seems to be necessary. In particular, legislation seems to be needed in each state to allow inclusion in a nonbypassable wires charge -- analogous to the nonbypassable wires charges for certain public benefit programs -- of the costs of IGCC projects approved by the state PUC for coverage under the 3Party Covenant. It also seems to be necessary for legislation to set forth reasonably detailed provisions, as discussed in Section 9.2 above and applicable only to such IGCC plants, for: upfront review of each IGCC project and issuance of a certificate of public convenience and necessity; ongoing prudence review of project preconstruction and construction costs and operating costs; assurance of pass-through of approved depreciation and amortization of capital expenditures and associated return on capital (including cases of cancelled or inoperable plant) and of approved operating costs, with return-on-capital recovery starting during construction; and authorization to set a fixed equity return. In addition, the state legislatures should ensure that their state PUCs are authorized to impose fees on IGCC-project owners to defray the costs of administering the model regulatory mechanism.

It should be noted that some of these provisions are inconsistent with the statutory provisions that were in effect before Ohio and Texas adopted retail electric competition, when the two states had more traditional regulatory systems. Prior to deregulation of retail sales, in Ohio, rate base was limited only to capital investment in used and useful plant, amortization of cancelled-plant costs was barred, inclusion of CWIP in rate base was severely restricted, and adjustment-clause recovery was limited to fuel costs (plus to some extent coal research and development costs). In Texas, before retail sales deregulation, rate base was limited to used and useful plant, return of (but not return on) capital was allowed for cancelled plant through amortization, rate-base treatment of CWIP was allowed only where necessary for the utility's financial integrity, and adjustment-clause recovery was limited to fuel and purchased power costs.

In addition, in Ohio (but not in Indiana, Kentucky, New Mexico, and the ERCOT region in Texas), in order for the state PUC to have exclusive jurisdiction over the rates through which the IGCC project costs are recovered, it may be desirable for the state PUC (perhaps supported by the state attorney general) to make it clear that a utility distribution company may own or lease a new IGCC plant approved by the state PUC for coverage under the 3Party Covenant. Under the more traditional approach to utility regulation in Indiana and Kentucky, of course, an electric utility may own or lease a new IGCC plant and sell the output to retail customers. As discussed above, Ohio statute is not entirely clear but does not seem to bar utility distribution companies from owning or leasing electricity generating plants. If an IGCC project is instead owned by an affiliate of the utility distribution company (or an independent power producer), then the provision of capacity and electricity to the utility distribution company for sale to retail customers involves a sale for resale, which, in Ohio (as well as Indiana, Kentucky, New Mexico, and outside the ERCOT region of Texas), invokes FERC jurisdiction over the rates for IGCC plant.

The types of legislative changes discussed above for Ohio are arguably consistent with Ohio's policy of "[e]ncourag[ing] innovation and market access for cost-effective supply- and demand-side retail electric service" (ORCA 4928.02(D)). However, in considering these types of change, Ohio and Texas will, of course, consider other relevant state policies, such as those concerning promotion of retail electric competition in Ohio and Texas and encouragement of new gas-fired generation and renewable-energy generation in Texas.

9.5. FERC jurisdiction over review, approval, and recovery of IGCC project costs.

As previously noted, the model state PUC regulatory mechanism described above assumes that the state PUC has exclusive rate jurisdiction for the new IGCC plant. The state PUC has exclusive rate jurisdiction when the financing, ownership, and operation of the new IGCC plant are structured in a way (i.e., in first and second project scenarios) that avoids sale for resale of electricity in interstate commerce from the plant. Sales for resale in interstate commerce (e.g., under the third and fourth project scenarios) are subject to the rate jurisdiction of the FERC. In general, to the extent the IGCC project scenario for financing, ownership, and operation involves sales for resale, the FERC has jurisdiction over rates for recovery of the IGCC project costs allocated to such sales and the scope of state PUC review of recovery of such costs is limited. See Section 7.11 above.

Under Section 205 of the Federal Power Act, all rates for sales for resale in interstate commerce must be "just and reasonable" (16 U.S.C. 824d(a)) and must not result in "undue preference or advantage" or "undue prejudice or disadvantage" (16 U.S.C. 824d(b)).[187] The FERC must review sale-for-resale rate filings and approve only those that meet the requirements of Section 205. Further, under Section 206, the FERC must set just and reasonable rates if it determines, on its own motion or in response to a complaint, that any rate is "unjust, unreasonable, unduly discriminatory or preferential." 16 U.S.C. 824e(a). In setting just and reasonable rates, the FERC must take into account potential, anticompetitive effects. For example, where a utility makes both wholesale and retail sales, the FERC must consider whether the utility's rates are so high that a wholesale customer cannot compete with the utility at the retail sale level (a circumstance referred to as "price squeeze"). If a price squeeze is demonstrated, the FERC must set rates at a level within the zone of reasonableness for just and reasonable rates that will mitigate the problem. Conway Corporation v. Federal Power Commission, 510 F.2d 1264 (D.C. Cir. 1975), aff'd, 426 U.S. 271 (1976).

9.51. Market-based rates.

In setting just and reasonable rates, the FERC has traditionally approved rates based on the cost of service of the wholesale-seller. However, consistent with the FERC's current

[187] In addition, if a seller qualifies as an exempt wholesale generator under 15 U.S.C. 79Z-5a(a)(1), the FERC cannot approve the seller's rates if they result from any "undue preference or advantage" from an associate or affiliate of a utility. 16 U.S.C. 824m. This does not appear to be significantly different than the requirements that rates be just and reasonable, and not result in undue preference or advantage, or undue prejudice or disadvantage, under Section 205 of the Federal Power Act. In addition, under 15 U.S.C. 79Z-5a(k), an electric utility company may not enter into a contract to purchase electricity purchase from an exempt wholesale generator that is an affiliate or associate, unless the contract is approved by each state PUC with jurisdiction over the retail rates of the electric utility company or, in the absence of such jurisdiction, each state PUC with jurisdiction over the retail rates of any affiliate or associate to which the electricity is to be resold. The consequences of exempt-wholesale-generator status are not discussed further in this paper.

focus on promoting a competitive, wholesale electricity market, the FERC has been approving market-based rates, rather than cost-based rates, if certain conditions are met. See, e.g., Boston Edison Co., 55 FERC ¶ 61,382 at 62,167 (1991). In fact, the FERC currently applies cost-of-service ratemaking in a minority of cases, and the number of such cases may decline further in the future.

Qualification for market-based rates.

The FERC allows market-based rates for sales for resale if there are showings that: the seller lacks generation market power and transmission market power or has adequately mitigated its market power; the seller cannot impose any other barriers to generation market entry; and the transactions have no potential for abuse through self-dealing or reciprocal dealing. AEP Power Marketing, Inc., 97 FERC ¶ 61,219 at 61,969 (2001), on reh'g., 107 FERC ¶ 61,018 (2004), on reh'g, Docket Nos. ER 96-2495-018, et al. (July 8, 2004).

According to the FERC, in an arms-length transaction involving a non-affiliated seller and buyer (e.g., sales from an independent-power-producer-owned IGCC plant to a distribution utility), there is no potential abuse since the buyer has no economic incentive to favor anyone except the least-cost supplier. In such a case, the FERC evaluates whether the seller has market power in order to ensure that the seller cannot limit supply or transmission options and thereby raise the price. Boston Edison, 55 FERC at 62,168. A seller has market power when, for example, the seller can significantly influence price in the market by restricting supply (generation market power) or denying access to alternative sellers (transmission market power). Id. at 62,167 n.54.

In contrast, when a transaction involves a seller and a buyer that are affiliates (e.g., sales from an IGCC plant owned by an affiliate of a distribution utility to that utility), the FERC maintains that there may be potential abuse. If the seller is not regulated and the buyer is, the seller can charge excessive prices to the affiliated buyer and retain the profit. If the seller is regulated and the buyer is not, the seller can charge preferentially low prices to the affiliated buyer and disadvantage the buyer's competitors. Id. at 62,168 n. 56. In a transaction between affiliates, the company must demonstrate a lack of abuse, regardless of whether the company has generation or transmission market power. Id. at 62,169 n. 67. The company may make this demonstration by showing, for example, direct competition between its affiliate and unaffiliated, alternative suppliers and justifying the choice of the affiliate. Id. at 62,168. Alternatively, the company may provide benchmark evidence on the prices, terms, and conditions for similar services in contemporaneous transactions in the relevant market involving non-affiliated buyers or non-affiliated sellers.[188] Id. at 62,168-69. The FERC will conduct its own evaluation of potential abuse

[188] It is unclear how, in comparing prices, terms, and conditions for a new IGCC plant with benchmark prices, terms, and conditions, the FERC will treat: the potential for increased IGCC project costs due to the risk of deploying new, complicated technology; or the IGCC project costs for meeting environmental goals beyond current environmental requirements (e.g., equipment and design costs related to mercury emission

in an affiliate transaction even if the state involved also will review the transaction. Id. at 62,170.

In addition to the demonstrations concerning potential abuse through self-dealing or reciprocal dealing, any seller seeking market-based-rate approval must show that the company and its affiliates: are not dominant in electricity sales in the relevant market; do not own or control transmission facilities through which the buyer could reach alternative suppliers (or if they do own or control such facilities, they have mitigated their ability to block access); and cannot erect or control any other barriers to generation market entry. Id. at 62,176. The second showing of absence or mitigation of transmission market power is generally made if the company and its affiliates have FERC-approved open access transmission tariffs. AEP Power Marketing, 97 FERC at 61,969. The third showing of absence of other barriers to generation market entry involves consideration of matters such as ownership or control of key inputs for construction of generation or transmission facilities. See Richmond County Power, LLC, 96 FERC ¶ 61,149 at 61,641 (2001) (discussing, as one potential barrier to entry under the third showing, ownership or control of a natural gas distribution system).

With regard to the first showing of lack of dominance in the generation market, the FERC does not require such a showing for wholesale sales from a new electricity generating plant (i.e., a plant commencing construction on or after July 9, 1996, which is the effective date of the Order No. 888 requiring open access transmission) in order for the rates for the sales to be market-based. 18 CFR 35.27(a); see AEP Marketing, Inc., 107 FERC at 61,068; LG&E Capital Trimble County LLC, 98 FERC ¶ 61,261 (2002); and Kansas City Power & Light Co., 67 FERC ¶ 61,183 at 61,557 (1994), clarified, American Power Service Corp., 70 FERC ¶ 61,358 (1995) (explaining that sellers lack generation market power with regard to new electricity generating facilities because industry and statutory changes "allow ease of market entry").

This exception has limited effect because the FERC still applies the remaining market-based-rate criteria (i.e., lack of transmission market power, lack of other barriers to generation market entry, and lack of potential abuse of self-dealing or reciprocal dealing) and still considers any submitted evidence that the seller has generation dominance with regard to new capacity. Order No. 888, 61 Fed. Reg. 21552-53. Moreover, if the seller owns, or has an affiliate that owns, generation or transmission facilities and is already using, or seeking to use, market-based rates in connection with existing facilities, the seller must show that the addition of the new electricity generating plant will not result in generation market power and therefore affect the qualification to use such market-based rates. AEP Power Marketing, 107 FERC at 61,068; LG&E Capital Trimble County, 98

controls or carbon capture and sequestration). For example, limiting the benchmark to prices for sales from plants using similar generation technology seems problematic given the limited number of existing IGCC plants in the U.S. See Ocean State Power II, 59 FERC ¶ 61,360 at 62,334-35 (1992), reh'g den., 69 FERC ¶ 61,146 (1994) (using, for benchmark, prices for projects of similar size and technology as plant whose rates are at issue). Also, considering the costs of emission controls not generally required by law seems problematic without considering the environmental costs imposed by facilities lacking such controls.

FERC ¶ 61,261; see also Zond Development Corp., 80 FERC ¶ 61,051 at 61,153 (1997). Because of the large capital investment and technological complexity involved in the construction of a new IGCC plant, it seems likely that the owner of such a plant will be an experienced participant in the electricity generation market and will already own, or have an affiliate that owns, existing generation for which the owner or affiliate wants to use market-based rates. Consequently, the exception for new electricity generating plants from the requirement to show lack of generation market power seems likely to have limited significance in the case of a new IGCC plant subject to FERC rate jurisdiction.

The FERC is still in the process of refining the requirements for a demonstration that a company and any affiliate lack generation market power. According to the FERC, the demonstration of lack of generation market power has generally focused on whether the company's (including any affiliates) share of installed and uncommitted generation in each relevant market exceeded 20 percent. However, in light of recent changes in the electricity market, the FERC is conducting a generic review, inter alia, of the generation market power issue and has adopted interim tests for generation market power. AEP Power Marketing, 107 FERC at 61,050 and 61,059.

Initially, the FERC presented an interim test for generation market power using analysis referred to as the "Supply Margin Assessment screen". AEP Power Marketing, 97 FERC at 61,969. A company would fail the Supply Margin Assessment screen if the company's generation capacity exceeded the amount of the relevant market's surplus capacity above peak demand, regardless of whether the company's total generation capacity exceeded 20 percent of the market's total generation capacity. Under this approach, a company with capacity exceeding the market supply margin would be regarded as a "must-run supplier needed to meet peak load" and having the potential "to successfully withhold supplies in the market in order to raise prices." Id. at 61,970. The Supply Margin Assessment screen would not be applied to sales into a transmission system under an independent system operator (ISO) or regional transmission organization (RTO). If a company failed the Supply Margin Assessment screen, certain requirements would be imposed to mitigate market power.

Recently, the FERC presented a new interim test for generation market power. AEP Marketing, 107 FERC ¶ 61,018. The FERC replaced the Supply Margin Assessment screen with two screens, a pivotal supplier screen based on annual peak demand and a market share screen applied to each season of the year. The first screen analyzes whether peak demand can be met without the company's generation, i.e., whether the company's uncommitted capacity available to the market area is less than the total uncommitted capacity available above peak demand. The second screen analyzes whether the supplier is dominant or large relative to other suppliers, i.e., whether the company's uncommitted capacity available to the market area is less than 20 percent of total uncommitted capacity available in each season. Id. at 61,060-61 and 61,064-66. The relevant market areas are generally the company's control area and the control areas of adjacent companies. Passing both screens establishes a rebuttable presumption that the company lacks generation market power. Failure to pass either screen establishes a rebuttable presumption that the company has generation market power, in which case the company may rebut the presumption, propose mitigation measures, or use cost-based rates (i.e., either default rates based on embedded cost of service for sales exceeding one year or some other cost-based rates approved by the FERC). Id. at 61,082. The two screens are applied to all companies, including those selling into a transmission system under an independent system operating or a regional transmission organization. The FERC also modified the requirements for mitigation measures.

Interaction of FERC market-based-rate review with state PUC rate procedures.

Assuming that the FERC's requirements for market-based rates for sales for resale for a new IGCC plant are met, it seems that the model state PUC regulatory mechanism (described in Section 9.2 above when applied to the first and second project scenarios) can be adapted to apply to the plant under the third and fourth project scenarios. Under the third project scenario (IGCC plant used for both end-user sales and sales for resale), the IGCC project costs are allocated between retail sales under state PUC jurisdiction and wholesale sales, which are under FERC jurisdiction unless the exception for plants in the ERCOT region of Texas applies.[189] It seems that the state PUC can apply the model state PUC regulatory mechanism for two purposes. First, the state PUC can apply the model regulatory mechanism in considering recovery of the share of the IGCC project costs allocated to sales to the IGCC plant's direct retail customers, based on a full prudence review of the IGCC project and costs. (The state statutory changes described in Section 9.4 above for first and second project scenarios may also be necessary for this application of the model regulatory mechanism under the third project scenario.) To the extent the IGCC project costs are approved by the state PUC, the retail-sales share is reflected in the IGCC adjustment clauses applicable to direct retail sales. Second, the state PUC can apply the model regulatory mechanism in considering the pass-through, to the IGCC plant's indirect retail customers in the state, of the share of costs that are allocated to wholesale sales and approved by the FERC under market-based analysis. (This application of the model regulatory mechanism may also require the state statutory changes in Section 9.4 above, but modified to reflect any limitations, discussed below, on the issues that the state PUC may consider in reviewing the pass-through of FERC-approved costs.) The state PUC review of such pass-through is generally limited to

[189] The state PUC (for retail sales) and the FERC (for wholesale sales) may independently determine the allocation of IGCC project costs between retail and wholesale sales. In particular, the state PUC may allocate a smaller portion of the costs to retail sales than is implied by the FERC's allocation to wholesale sales so long as the state PUC allows pass-through of all the FERC-approved costs. See, e.g., Central Kansas Power Co. v. State Corporation Commission of Kansas, 561 P.2d 779, 783 and 791 (Kan. 1977); and Public Service Co. of Indiana, Inc. v. Federal Energy Regulatory Commission, 575 F.2d 1204, 1218 (7th Cir. 1978). The potential problem that this raises is discussed below in this Section 9.5. If all wholesale sales from the IGCC plant will be on the spot-market (rather than to firm wholesale customers), all of the return of and on capital of the plant may be allocated to retail sales. See Section 9.1 above.

review of the prudence of the quantity of electricity contracted for or purchased by the wholesale purchaser and must treat, as just and reasonable, the wholesale price approved by the FERC.[190] If the quantity of electricity is approved by the FERC through review of an inter-company agreement, the state PUC may be pre-empted from reviewing quantity as well as price. See Section 7.1 above.

Once the FERC determines that a wholesale purchase agreement for a new IGCC plant meets the requirements for market-based rates, it seems that the FERC will not review the specific provisions of that agreement, but rather will find the agreement as a whole to be just and reasonable. See Ocean State Power II, 69 FERC ¶ 61,146 at 61,546 (explaining that market-based rate review does not involve consideration of the seller's cost structure or any individual components of the rate). In essence, the FERC's review is based on analysis of the market conditions under which the agreement was negotiated, rather than of the specifics of the rates in the agreement. Consequently, from the standpoint of the FERC, a wholesale purchase agreement meeting market-based requirements and incorporating elements of the model regulatory mechanism (such as guaranteed recovery of approved capital investment and return on capital, a fixed equity return, recovery of return on capital on CWIP, and adjustment-clause cost recovery) may well be approvable.[191] But see Ocean State Power, 44 FERC ¶ 61,261 at 61,976-77 and 61,981-83 (1988) (approving, as market-based rates, formula rates for new plant covering capital expenditures and return on capital, but with return on equity based on generic market conditions and calculated annually and provisions putting risk of cost overruns, construction delays, achievement of commercial operation and design capacity, and plant availability on plant owner). Similarly, if the wholesale purchase agreement reflects the retail-wholesale allocation of IGCC projects costs that is determined by the state PUC, it seems that the FERC may accept that allocation without further review.

However, a state PUC may be concerned about applying the model regulatory mechanism and allowing adjustment-clause pass-through of IGCC project costs (including costs of cancelled plant), unless the state PUC retains the ability to protect indirect, as well as direct, retail customers of the IGCC plant through full prudence review by the state PUC. If a significant portion of the costs will be passed through based on FERC market-based approval and the state PUC is concerned that its review will be severely limited with regard to the FERC-approved costs, the state PUC may be unwilling to allow adjustment-clause pass-through of project costs and may generally be

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[190] Whether the FERC approves rates as market-based or cost-based, the ultimate finding by the FERC is that they are just and reasonable (see Town of Norwood, Massachusetts v. New England Power Co., 202 F.3d 408, 419 (1st Cir. 2000), cert den., 531 U.S. 818 (2000)), and, because of federal pre-emption, the state PUC must treat them as just and reasonable in state rate proceedings.

[191] The FERC will have the authority under Section 206 of the Federal Power Act to revisit its market-based-rate (or cost-based-rate) approval of the wholesale purchase agreement and to prospectively revise its approval decision. However, as discussed below, the FERC can indicate that such a revision is unlikely to occur. See Great Plains Gasification Associates, 15 FERC ¶ 61,106 at 61,242 (1981), modified, 16 FERC ¶ 61,121 (1981) (where FERC declined to foreclose possible future modification of approved, cost-based formula rate but stated, inter alia, that it did not "envision" such a modification).

unwilling to support the project. As discussed above in Section 7.11, the state PUC must allow pass-through of the FERC-approved costs, although it is not required to implement the pass-through in an adjustment clause and instead may require recovery through traditional rate increase filings and rate cases.

Below are discussed two possible approaches to address potential state PUC concerns about allowing adjustment-clause recovery of IGCC project costs allocated to wholesale sales because of potential federal pre-emption of state PUC review of the costs. The first possible approach to addressing state PUC concerns about federal pre-emption may be for the owner of the IGCC project to agree to establish, in the wholesale purchase agreement for the project, formula wholesale rates that are limited to recovery of the wholesale-sales share of those IGCC project costs that are approved by the state PUC under full prudence review.[192] This type of pricing provision in the wholesale purchase agreement will preserve the ability of the state PUC to protect all retail customers of the IGCC plant in the state by reviewing all IGCC project costs and disallowing imprudently incurred costs. The wholesale purchase agreement with such a rate provision will, of course, be subject to FERC jurisdiction and is assumed, for purposes of this discussion, to meet the criteria for market-based rates.

Even with that assumption, this first approach raises two questions. One question is whether the FERC will approve for an IGCC project such a wholesale purchase agreement, which subjects cost recovery to the state PUC's full prudence review. The FERC will not, in any event, be conducting any cost-of-service or prudence review concerning the rates under the agreement since the agreement meets the FERC's market-based-rate requirements. The state PUC's prudence review will not duplicate any similar proceedings by the FERC, and there is no potential for specific, contradictory state PUC and FERC prudence findings. Consequently, it seems that the FERC may not have any policy reason for disapproving the agreement unless the FERC views the ability of state PUC prudence review to affect wholesale rates as inconsistent with the concept of rates based on the market rather than on the results of rate review.

The second question is whether approval by the FERC of (and prudence review by a state PUC pursuant to) such an agreement will be a violation of federal pre-emption in the

[192] A similar type of pricing provision, referred to as a "regulatory-out" clause, is used in some wholesale purchase agreements, i.e., contracts for sales by qualifying facilities under PURPA to utilities. The regulatory-out clause excludes from payments required by the utility under the contract any costs that the state PUC bars such utility from passing through to retail customers. See, e.g., Florida Power & Light Co. v. Beard, 626 So.2d 660, 661-62 (Fla. 1993); Freehold Cogeneration Associates L.P. v. New Jersey Board of Regulatory Commissioners, 44 F.3d 1178, 1193 n.12 (3d. Cir. 1995), cert. den., 516 U.S. 815 (1995); Agrilectic Power Partners Ltd. v. Entergy Gulf States Inc., 207 F.3d 301, 302 n.3 and 303-04 (5th Cir. 2000) (stating that regulatory-out clause is valid because PURPA allows private parties to contract for whatever rates they prefer); and North American Natural Resource, Inc. v. Strand, 252 F.3d 808, 813 n.4 (6th Cir. 2001). However, some courts have indicated that such a regulatory-out clause does not confer, on the state PUC, authority to conduct traditional rate review of the PURPA contract price because such review is pre-empted by PURPA. Freehold Cogeneration, 44 F.3d at 1193-94; North American Natural Resource, 252 F.3d at 813-14.

regulation of wholesale sales. This seems to be a closer question than the first. In this case, the FERC will be approving, as market-based and just and reasonable, an agreement that sets wholesale sales rates based on the state PUC's prudence determinations. It is arguable that, if this results in a state PUC finding that certain costs are imprudent and in the exclusion of those costs from recovery under the wholesale sales rates, there is no trapping of FERC-approved costs. See Nantahala Power and Light, 476 U.S. at 971-72 and Mississippi Power & Light, 487 U.S. at 372 (explaining that federal pre-emption bars a state PUC from "trapping" federally approved costs). The excluded costs are costs that the FERC agreed, in approving the wholesale sales agreement, should be excluded if the state PUC finds them imprudent.

Moreover, it is also arguable that, in approving this type of agreement, the FERC is not ceding, to the state PUC, federal authority over wholesale rates by allowing the state PUC to ignore or contradict any federal determination. The FERC is exercising its authority by analyzing the market conditions under which the agreement was negotiated and approving the rate as resulting from negotiation in a competitive market, without making any determinations about the reasonableness of the underlying costs. The FERC is then allowing the state PUC to review the reasonableness of the underlying costs, which the FERC has found it unnecessary to review. This may be viewed as analogous to the distinction made by the courts, in explaining the limits on state PUC prudence review in Nantahala Power & Light (476 U.S. at 972) and other cases, between a determination of what is the reasonable rate for wholesale sales and a determination of what is a reasonable quantity of electricity to purchase at that rate. See Section 7.11 above (discussing Pike County Light and Power and similar cases). When the FERC determines only the rate, the state PUC may determine the quantity that is prudent; here, when the FERC determines only that the rate was negotiated in the context of a competitive market, the state PUC may determine what costs the rate may include. However, because of exclusive federal jurisdiction over wholesale sales, the FERC has rejected a provision, requested for a system integration agreement, that would bar charges not "in accordance with" state law and state PUC regulations and orders. Progress Energy, Inc., 97 FERC ¶ 61,141 (2001). The provision was rejected as inconsistent with exclusive federal jurisdiction. See also Pleasants Energy, LLC, 99 FERC ¶ 61,024 (2002) (rejecting power purchase agreement provision barring charges not "in accordance with" state law).

In summary, it is not clear whether a wholesale purchase agreement limiting costs to those that the state PUC finds prudent will be viewed as violating the principal of federal pre-emption or as otherwise inappropriate in the context of market-based rates.[193]

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[193] In analyzing the legality of this type of agreement, consideration was given to the concept of a provision in which the IGCC plant owner would expressly waive the right to raise any claim of federal pre-emption in any state PUC prudence review and related judicial review as a basis for challenging disallowance of costs. This type of waiver has been used under other circumstances. For example, the NMPRC required such a waiver, as a condition for approval of a utility merger and reorganization

A second possible approach to addressing potential state PUC concerns about federal pre-emption is to make state PUC approval of the IGCC project costs allowed in rates by the FERC, and state PUC agreement to allow adjustment-clause pass-through of the state-PUC-approved costs, a condition of the federal guarantee for the IGCC project. Under this approach, the formula rate in the wholesale purchase agreement does not limit recovery to the costs approved by the state PUC. Instead, it is made a condition of the federal loan guarantee that, after the state PUC issues a certificate of public convenience and necessity for the IGCC project (under paragraph 1 of the model state PUC regulatory mechanism) and as construction progresses, the state PUC must conduct periodic, ongoing review of the IGCC preconstruction and construction costs, regardless of whether the project is under FERC rate jurisdiction. As a further condition of the federal loan guarantee, the federally guaranteed loan for the debt-funded share of the portion of such costs is disbursed only to the extent the state PUC approves the costs for pass-through to indirect retail customers of the IGCC project in an IGCC fixed-cost adjustment clause.[194] It should be noted that, under the third project scenario, the state PUC is already conducting ongoing prudence review of the portion of the preconstruction and construction costs allocated to retail sales. The state PUC's review of FERC-approved preconstruction and construction costs for purposes of adjustment-clause pass-through necessarily involves application of different criteria than in a prudence review,[195] but can be coordinated with the state PUC's review of the retail-sale portion of the project's preconstruction and construction costs. To the extent any FERC-approved preconstruction and construction costs are disallowed by the state PUC for adjustment-clause pass-through, the state PUC must allow their pass-through to indirect retail customers of the IGCC project through a general rate case (unless the state PUC makes an imprudence finding that is not barred by federal pre-emption). However, this approach puts strong pressure on the IGCC-project owner to meet the state PUC's approval criteria

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anticipated to result in an increase in the size and number of wholesale transactions subject to FERC jurisdiction and a reduction in the ability of the NMPRC to regulate the utilities involved. The utility agreed not to raise any claim of federal pre-emption as a basis for challenging future state PUC review of any affiliate-transaction costs attributed to retail service, the allocation of such costs to New Mexico customers, and the reasonableness of the underlying affiliate-transaction agreements. The utility also agreed that its investors will bear the consequences of any adverse determinations by the NMPRC. Southwest Public Service Co., 1997 WL 78696 at 34 and 42 (NMPRC Jan. 28, 1997). Requiring such a federal-pre-emption-claim waiver in the case of the wholesale purchase agreement suggested above for IGCC plants seems to be of limited usefulness. First, if the waiver results in a reduction in costs included in the wholesale rate, the FERC may have to approve such a reduction, in which case the same considerations discussed above in the absence of the waiver will come into play. Further, it is questionable whether the waiver will really be binding and effective in future proceedings. While the waiver will likely bind the IGCC plant owner making the waiver, it will not likely bind any other parties that may want to raise a federal pre-emption claim. Such parties may include: the IGCC plant owner's shareholders or bondholders; or competitors concerned about the competitive advantage resulting from a cost disallowance and concomitant price reduction for the IGCC plant.

[194] Although not a condition for disbursement of the federally guaranteed loan, there may also be state PUC review of the plant's operating costs to determine whether to allow them in adjustment-clause pass-through.

[195] It is not clear what these non-prudence criteria will be and to what extent their application will satisfy the state PUC's interest in protecting indirect retail customers of the IGCC project.

for adjustment-clause pass-through in order to obtain such pass-through and to qualify for coverage of the debt-funded portion of the costs by the federal loan guarantee. This may satisfy a state PUC's interest in having effective review of the costs in order to protect retail customers.

With regard to the fourth project scenario (IGCC plant used only for sales for resale), if the conditions for market-based rates for sales for resale for a new IGCC plant are met, it seems that the model state PUC regulatory mechanism can be adapted to apply to the plant in a manner similar to that described above for the third project scenario. Under the fourth scenario, all IGCC project costs must be recovered initially through wholesale rates, over which the FERC has exclusive jurisdiction (unless the exception for plants in the ERCOT region of Texas applies). The two possible approaches discussed above concerning the third project scenario seem applicable to the same extent to the fourth project scenario. (The application of the model regulatory mechanism under the fourth project scenario may require the state statutory changes described in Section 9.4 above for the first and second project scenarios, but modified to reflect any limitations on the issues that the state PUC may consider in reviewing the pass-through of FERC-approved costs.)

9.52. Cost-based rates.

If the conditions for market-based rates are not met, the FERC continues to use cost-based ratemaking (described generally in Section 7.12 above) to set rates for wholesale sales. The application, under these circumstances, of the model regulatory mechanism described above in Section 9.2 raises questions about whether the key elements of the model regulatory mechanism are consistent with FERC policy and will be applied by the FERC in its cost-based-rate review and, if so, whether the use of model regulatory mechanism by the FERC can be reconciled with the interest state PUCs' likely interest in retaining the ability to conduct their own review of IGCC project costs in order to protect retail customers.

Consistency of FERC cost-based-rate review with model regulatory mechanism.

It is not clear whether, or to what extent, the FERC's approval of cost-based rates will include certain elements of the model mechanism that are necessary to provide an assured revenue stream to support the federal loan guarantee under the 3Party Covenant. The main elements of the model regulatory mechanism that are at issue are: ongoing (rather than only after-the-fact) prudence review; construction-period recovery of return on capital for construction work in progress; recovery of capital investment and return on capital for cancelled plant; recovery of capital investment, return on capital, and operating costs through an adjustment clause; and a fixed return on equity.

Like many state PUCs, the FERC generally conducts after-the-fact prudence review of electricity generating plant: i.e., review after the plant is completed and operating, or after construction of the plant is terminated, and when the utility requests inclusion in rate base of the capital investment in the plant. See, e.g., Violet, 800 F.2d 280 and NEPCO Municipal Rate Committee, 668 F.2d at 1332-35 (upholding the results of after-the-fact prudence review of cancelled plant); see also Iowa State Commerce Commission v. Federal Inspector of the Alaskan Natural Gas Transportation System, 730 F.2d 1566, 1571 (D.C. Cir. 1984) (explaining that FERC's "traditional tool for cost control" is "retrospective" review of capital outlays and determination and disallowance of imprudent expenditures).

In only a few cases has the FERC been involved in ongoing (rather than after-the-fact) review of plant construction and determination of prudent expenditures, similar to the approach reflected in the model regulatory mechanism. In one example, ongoing review was mandated by Congress for the Alaskan Natural Gas Transportation System (ANGST), a pipeline that was to be constructed to transport natural gas from Prudhoe Bay, Alaska through Canada to U.S. pipeline-purchasers in the lower 48 states. Because of the enormous outlays of private capital necessary for construction of the pipeline, Congress determined that the traditional approach of post-construction review of project costs and disallowance of imprudent costs was not sufficient "to assure cost control and minimize uncertainty of investors about future revenues." Id. Instead, Congress required timely review and approval of capital outlays for the pipeline on an ongoing basis for inclusion in rate base. Ongoing review was a "vital part of the…mechanism for facilitating the raising of capital for ANGTS by reducing the risks for ANGTS investors without shifting the risks of cost overruns to the consumer." Id. at 1572. Without ongoing review, the rate base on which ANGST investors would receive a rate of return could remain uncertain for years until completion of after-the-fact review. Id.

The FERC delegated its authority to conduct ongoing review of costs, and determine the rate base, for the ANGST to the Office of the Federal Inspector (OFI), which Congress had already given certain oversight responsibilities for the pipeline. Delegation of Authority by the Federal Energy Regulatory Commission to the Office of the Federal Inspector, 45 Fed. Reg. 85511 (1980). The FERC stated that this delegation was appropriate in light of the OFI's ongoing cost control responsibilities concerning the ANGST and that the FERC would treat, as final, the OFI's determinations about what costs were prudent and should be included in rate base. Id. The OFI had extensive cost control responsibilities, including pre-construction review and approval of management systems, project design, cost estimates, construction schedule, and quality assurance and control procedures. Order No. 3, 46 Fed. Reg. 51726, 51727 (OFI 1981). The OFI also had responsibility for reviewing contractor selection and procurement. Under the OFI's expedited procedures, expenditures consistent with approved systems, design, and plans could not be challenged on grounds of prudence and were reviewed for inclusion in rate base on a quarterly basis. Id. at 51727-29.

In addition to imposing the requirement of ongoing review, Congress limited the FERC's ratemaking authority concerning the ANGST. Specifically, the FERC could disallow expenditures as imprudent, and reduce rates, so long as this "did not impair recovery of the actual operation and maintenance expenses, actual current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt." Metzenbaum v. Federal Energy Regulatory Commission, 675 F.2d 1282, 1289 (D.C. Cir. 1982) (holding that challenge of this limitation was not ripe for judicial review).

The above-described ongoing review process was, of course, developed uniquely for the ANGST. Like under the model regulatory mechanism, capital expenditures were reviewed and approved on an ongoing basis during construction and approval of such expenditures was final, guaranteeing their inclusion in rate base. However, unlike under the model regulatory mechanism, the reviewing agency (OFI) was also deeply involved in review and approval of the planning, design, and management of the pipeline project even before construction commenced. The model regulatory mechanism does not require -- but does not bar -- such intimate involvement by the utility regulatory commission, but, like the ANGST review process, uses ongoing review to reduce investor risk and facilitate capital investment, while protecting ratepayers.

Another example of FERC approval of involvement in ongoing review of plant construction and determination of prudent expenditures is the FERC's certification of the Great Plains coal gasification plant in North Dakota. In that case, the FERC issued a certificate of public convenience and necessity for coal gasification plant to produce synthetic gas to be commingled with natural gas and transported and sold by interstate natural gas pipelines. Great Plains Gasification Associates, 9 FERC ¶ 61,221 (1979), reh'g den., 10 FERC ¶ 61,066 (1980), modified, 11 FERC ¶ 61,339 (1980), rev. sub nom. Office of Consumers' Counsel v. Federal Energy Regulatory Commission, 655 F.2d 1132 (D.C. Cir. 1980). The FERC viewed the plant as a commercial demonstration of coal gasification. According to the FERC, the demonstration was in the national interest because the technology could provide an alternative to expensive, insecure foreign energy supplies. Further, the demonstration would provide important information (e.g., on plant costs, efficiency, and environmental impact) and reduce or resolve uncertainties concerning the technology, thereby facilitating future conventional financing of coal gasification plants. Great Plains, 9 FERC ¶ 61,221 at 61,410.

The FERC therefore approved several provisions to ensure the financing of the plant. These provisions included: project financing of the plant with 75 percent debt; guaranteed recovery of debt principle and interest, including in the case of project abandonment; recovery of equity subject to traditional prudence review; ongoing recovery of return on capital for construction work in progress; and use of a rate analogous to an adjustment clause (referred to as a "cost-of-service tariff"), adjusted every six months, for recovery of costs from the pipeline-customers and use of a tracking mechanism for recovery of these costs by the pipeline-customers from their own customers. Id. at 61,447. The FERC declined to approve a fixed 13 percent rate of return and instead provided for periodic (every three years) review of the rate of return. Id. at 61,431-32. The FERC also declined to guarantee that the rate provisions would continue until all debt was repaid, but noted the “reliance” of the lenders and project sponsors on these arrangements in committing capital to the project. Id. at 61,424. Finally, the FERC stated that it would institute a system for ongoing monitoring of the construction and operation of the project, including periodic reports, on-site inspections, auditing of construction and operating expenditures, and review of plant design and specifications.

Upon judicial review, the FERC’s certification of the Great Plains coal gasification plant was overturned on the ground that the FERC had jurisdiction to certify facilities for interstate transmission and sale of natural gas (and of commingled natural gas and synthetic gas), but not a plant for producing only synthetic gas. Office of Consumers’ Counsel, 655 F.2d at 1145-49. Consequently, the ratemaking and ongoing monitoring regime approved by the FERC for the plant was never implemented. However, the case indicates that -- at least in cases of unique facilities that the FERC determines promote the national interest in reducing reliance on foreign energy -- the FERC may adopt an ongoing review process similar in many respects to that under the model regulatory mechanism.

In addition to ongoing review, the model regulatory mechanism calls for inclusion of construction work in progress in rate base and recovery of costs of cancelled plant to the extent the costs were found to be prudent during the ongoing review. The FERC has in the past excluded, from rate base, CWIP and expenditures for cancelled plant on the ground that such items were not “used and useful.” See NEPCO Municipal Rate Committee, 668 F.2d at 1332-33; and Jersey Central Power & Light, 810 F.2d 1171-74.

However, the FERC currently allows rate base treatment for certain types of CWIP: 100 percent of CWIP involving pollution control and conversion of plants from oil or natural gas to other fuels; 50 percent of all other CWIP; and CWIP to the extent necessary to remedy severe financial hardship that cannot be otherwise alleviated without materially increasing the cost of electricity. The purposes of allowing rate base treatment for CWIP are to: mitigate the bias against new capital investment in needed facilities; facilitate more accurate evaluation of the need for new facilities; and mitigate sudden price increases and promote rate stability. Mid-Tex Electric Cooperative, Inc. v Federal Energy Regulatory Commission, 773 F.2d 327, 332 (D.C. Cir. 1985). In allowing rate base treatment of the second category (50 percent) of CWIP, the FERC adopted certain measures and procedures to protect against potential, anticompetitive effects (e.g., price squeeze) of this treatment of CWIP. See 18 C.F.R. 35.25; and Mid-Tex Electric Cooperative, Inc. v. Federal Energy Regulatory Commission, 864 F.2d 156 (D.C. Cir. 1988). See also Maine Yankee Atomic Power Co., 66 FERC ¶ 61,375 at 62,251 (1994) (applying 18 C.F.R. 35.25 and approving inclusion of 50 percent of CWIP in rate base). In addition, as noted above, rate base treatment of CWIP was allowed for demonstration projects, such as the Great Plains coal gasification project. Great Plains, 10 FERC ¶ 61,066 at 61,147. In allowing rate base treatment, the FERC seems to retain the authority to reverse the rate effect of such treatment if the plant is not ultimately put in service or the plant’s start-up is delayed. See Order No. 555, 56 FPC 2939, 2946 (1976), reh’g den., 57 FPC 6 (1977), aff'd, Oglethorpe Electric Membership Corp. v. Federal Energy Regulatory Commission, 574 F.2d 637 (D.C. Cir. 1978) (stating that, if plant is not put in service or plant startup is "inordinately delayed," FERC retains authority to conduct prudence review of expenses and to consider "redress [of] the excess costs based on inclusion in rate base of CWIP for that unit").

With regard to recovery of cancelled-plant costs, the FERC has allowed some, but not full, recovery of investment in cancelled electricity generating plant. For example, in New England Power Co., 42 FERC ¶ 61,016 at 61,081-83 (1988), on reh'g, 43 FERC ¶ 61,285 (1988), the FERC allowed 50 percent of prudent investment in cancelled nuclear plant to be amortized over the expected life of the plant and inclusion in rate base of the unamortized portion of that 50 percent (but reduced by deferred income taxes associated with the write-off of the remaining 50 percent). The FERC maintained that this results in a reasonable sharing of the costs of cancelled plant between investors and ratepayers. New England Power, 42 FERC ¶ 61,016 at 61,082. See Natural Gas Pipeline of America v. Federal Energy Regulatory Commission, 765 F.2d 1155, 1167 (D.C. Cir. 1985), cert. den., 474 U.S. 1056 (1986) (upholding FERC's denial of amortization of pipeline's development costs of terminated coal gasification project, liquified natural gas project, and Alaskan gas pipeline as "highly speculative" projects with "remote and uncertain" potential benefits for ratepayers and upholding different treatment of electric utility's failed nuclear plants). Only in unusual circumstances, has the FERC allowed 100 percent recovery of the investment in a cancelled plant. See Northeast Utilities Service Co., 51 FERC ¶ 61,177 at 61,484-85 (1990), clarified, 52 FERC ¶ 61,046 (1990) (approving agreement with provision for 100 percent recovery of capital investment of new owner in uncompleted nuclear plant in event of plant cancellation, as exception to FERC 50-percent-recovery policy, because provision is necessary to financing and reorganization of bankrupt original owner of nuclear plant). If only 50 percent of capital investment in a cancelled plant (e.g., an IGCC plant under the 3Party Covenant) is recoverable and debt is more than 50 percent of the investment, then the utility can recover (through amortization and rate base treatment) some but not all of the debt investment and interest on debt, much less any equity investment and return on equity. See New England Power, 43 FERC ¶ 61,285 at 61,779 (noting that FERC's 50 percent limit on recovery of capital investment is "neutral" concerning whether equity or debt investors bear the loss).

The model regulatory mechanism also includes the use of adjustment clauses for recovery of IGCC project costs. In a number of cases, the FERC has allowed the use of formula rates (also referred to as "cost-of-service rates") that comprehensively account for the costs of service for a plant (rather than singling out specific plant costs) and that operate similarly to a fuel adjustment clause. See Public Utilities Commission of California, 254 F.3d at 254, 256, and n.6; and Golden Spread Electric Cooperative, 39 FERC ¶ 61,322. For example, the FERC allows adjustment-clause recovery of the costs of projects approved as research, development, and demonstration projects. See Great Plains, 9 FERC ¶ 61,221 at 61,448; and Order No. 566, 58 FPC 2238, 2247-48 (1977), reh'g. den., 59 FPC 1505 (1977), recon. den., 2 FERC ¶ 61,023 (1978), aff'd sub nom. Transwestern Pipeline Co. v. Federal Energy Regulatory Commission, 626 F.2d 1266 (5th Cir. 1980), cert. den., 452 U.S. 973 (1981).

By further example, after the reversal on appeal of the FERC's approval of the above-described certification provisions for the Great Plains coal gasification plant, the financing of the plant was recast, using equity capital that was at risk in the event of plant failure, abandonment, or operation at less than design throughput and federally guaranteed debt. Great Plains Gasification Associates, 15 FERC ¶ 61,106. The FERC approved in advance, and declined to subject to periodic review, the inclusion of a formula rate for the synthetic gas (based on natural gas and oil prices) in the purchased gas adjustment clauses of pipeline-customers of the plant.[196] The FERC explained that this approach was unique to this project and necessary for the federal loan guarantee and private financing of the project to go forward. Id. at 61,242. Further, the FERC stated that it could not foreclose the possibility that it might modify the formula in the future. However, the FERC indicated that such a modification is unlikely by: stating that any modification must be due to "greatly changed ('truly exceptional') circumstances"; noting the importance of "price certainty for financing purposes"; and stating that the FERC does not "envision a change in the present authorization." Id. (footnote omitted). The FERC also expressly recognized that investors and lenders for the project were providing funds "in reliance" on the FERC order. Id. at 61,243.

The FERC has also approved formula rates that provide for recovery of capital investment, cost of capital, and operating costs for completed electricity generating plants. See, e.g., Southern California Edison Co., 106 FERC ¶ 61,183 at 61,639 and 61,643-45 (2004) (approving, as cost-based rates, formula rates for sales from new generating plant to affiliate and stating that FERC will apply, in cost-based review, Boston Edison standards for affiliate transactions in market-based review); Yankee Atomic Electric Co., 40 FERC ¶ 61,372 at 62,191 (1987), reh'g den., 43 FERC ¶ 61,232 (1988), order on remand, 47 FERC ¶ 61,258 (1989) (setting equity return in formula rates approved as cost-based rates); and Maine Yankee Atomic Power Co., 42 FERC ¶ 61,307 at 61,923 (1988), reh'g den., 43 FERC ¶ 61,453 (1988) (allowing formula rate as cost-based rate, but requiring inclusion of details of all formula calculations).

However, the FERC has a general policy against approving the automatic adjustment of rate of return in formula rates reviewed as cost-based rates. According to the FERC, this is because rate of return is affected by changes in both the specific utility's risks and general capital market conditions and so is not susceptible to accurate, automatic determination. Ocean State Power II, 69 FERC at 61,545-46. It is not clear whether the FERC will approve a fixed return on equity in a formula rate. On one hand, a fixed equity return has the advantage over an automatically adjusting equity return that the parties will know upfront what is the level of the return. On the other hand, the inability to change the

[196] The FERC also found that the pipeline-customers' synthetic gas purchase contracts were reasonable and stated that it would not revisit that issue in the future. Id. at 61,242-43.

return at any time in the future may be inconsistent with the FERC's authority under Section 206 of the Federal Power Act to determine just and reasonable rates when any rates are found to be unjust or unreasonable.

In summary, FERC cost-based-ratemaking policy seems to allow for adoption of many of the key elements of the model regulatory mechanism: ongoing review in unusual cases that promote reduced reliance on foreign energy; inclusion of some CWIP in rate base; guaranteed recovery of a portion of return of, and return on, capital in the event of plant cancellation; and cost recovery through an adjustment clause. FERC acceptance of certain other elements (full inclusion of CWIP in rate base, guaranteed full recovery of return of and on debt capital and of at least 50 percent of return of and return on equity capital, and a fixed return on equity) seem more problematic.

Interaction of FERC cost-based-rate review with state PUC rate procedures.

In cases where the FERC conducts cost-based (rather than market-based) rate review, it seems more difficult to reconcile FERC review with a state PUC's potential interest in conducting its own review of IGCC project costs to protect retail customers. As discussed above, there are two possible approaches to addressing state PUC concerns about federal pre-emption of state PUC review. The first possible approach (i.e., a wholesale rate limited to costs found by the state PUC to be prudent) is premised on the FERC approving, under the rubric of market-based rates, a wholesale purchase agreement that limits pass-through in wholesale sales rates of those IGCC project costs that are approved by the state PUC in full prudence review. However, if the FERC is conducting its own prudence review concerning the IGCC plant's wholesales rates under either the third[197] or fourth project scenario, it seems anomalous for the FERC to approve a wholesale purchase agreement that limits pass-through of the costs under those rates to the costs that the state PUC approves in a separate, independent prudence review. Under such circumstances, the state PUC prudence review would effectively duplicate and supersede the FERC's prudence review. The resulting potential for state PUC prudence determinations inconsistent with those of the FERC seems to violate federal pre-emption in the regulation of wholesale sales. In addition, the FERC may well view this arrangement as an inefficient use of administrative resources.

The second possible approach (i.e., a federal loan guarantee condition requiring state PUC review and approval of costs for adjustment-clause pass-through) to address state PUC concerns about federal pre-emption seems to raise fewer questions than the first approach. If FERC conducts cost-based-rate review under the third or fourth project scenario, both the FERC and the state PUC will review IGCC project costs allocated to wholesale sales, with the FERC review determining what costs are prudent and warrant

[197] An additional problem, unique to the third project scenario, is that the FERC and the state PUC may determine inconsistent allocations of IGCC project costs between wholesale and retail sales. Unless the two determinations result in a total allocation of 100 percent of the project costs, there may not be an assured stream of revenues to support the federal guarantee, as required under the 3Party Covenant.

pass-through and the state PUC review determining what portion of these costs should be passed through in adjustment clauses rather than general rate cases. As discussed in Section 9.51 above, this approach puts strong pressure on the IGCC-project owner to meet the state PUC's approval criteria for adjustment-clause pass-through and may satisfy state PUC concerns about effective state review of project costs.[198]

In summary, where wholesale rates for the IGCC project satisfy the FERC's requirements for market-based rates, there may be two possible approaches to reconciling FERC-market-based review and state PUC review and allowing the state PUC to apply the model state PUC mechanism (modified to reflect any limitations on the issues that the state PUC may consider) to the IGCC project under the third and fourth project scenarios. Where wholesale rates for the IGCC project must be reviewed by the FERC using cost-based analysis, it seems more difficult to apply the model regulatory mechanism and to accommodate both FERC and state review of recovery of costs under these project scenarios.

[198] The application of the model regulatory mechanism by the state PUC under either the two approaches (discussed above in the context of FERC cost-based-rate review) may require the state statutory changes described in Section 9.4 above, but modified to reflect any limitations on the issues that the state PUC may consider.