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. <u>See</u> 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. <u>See</u> 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. <u>Compare United Illuminating Co.</u>, 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) <u>with</u> <u>Cleveland Electric Illuminating Co.</u>, 76 FERC ¶ 61,156 at 61,925 (1996), <u>reh'g den.</u>, 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. <u>Ameren Energy Generating Co. and Union Electric Co.</u>, 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. <u>See</u> <u>United Illuminating</u>, 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. <u>See</u> 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

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[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

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[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

[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.