BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of a Working Case to Draft A Rule to Revise Commission Rule 4 CSR 240-3.105.	)))	File No. EW-2014-0239

DOGWOOD ENERGY, LLC'S COMMENTS

Pursuant to Commission Notice, Dogwood attaches its updated rulemaking proposal and provides its comments regarding revisions to 4 CSR 240-3.105. Dogwood's comments are based upon the principle that "the guiding star of the public service commission law and the dominating purpose to be accomplished by such regulation is the promotion and conservation of the interests and convenience of the public." State ex rel. Crown Coach Co. v. PSC, 179 SW2d 123, 128 (Mo App 1944). Accordingly, Dogwood suggests that the Commission's authority to protect the public interest pursuant to Section 393.170 should not be artificially constrained by an unduly narrow interpretation. Further, given that the Courts have already held that the Commission was not fully exercising its authority under Section 393.170, related rule changes should be viewed as necessary and appropriate, rather than "radical shifts" as suggested by the utilities in their opposition to Dogwood's prior Rulemaking Petition.

1. Whether separate certificates of convenience and necessity (CCNs) should be required for each generating unit at a multi-unit site, in particular if there is a lapse of more than two years between the end of construction of one unit and the beginning of construction of the next unit.

Yes, each generating unit at a multi-unit plant should be separately approved. Further, after a generating unit has been approved, if construction does not commence within two years of such approval, then application for approval must be resubmitted.

Section 393.170 requires advance Commission approval of construction of "an electric plant". The Commission can only approve such construction after hearing and a determination that it is "necessary or convenient for the public service." Such approval is only valid for two years, unless the authority granted is "exercised". Notably, specific projects are not approved in the context of Commission review of utility integrated resource plans. See 4 CSR 240-22.010(1).

"Electric plant" is very broadly defined in Section 386.020, such that each generating unit at a multi-unit site is separate "electric plant" that must be separately approved by the Commission (although multiple approvals could be set forth in one order if applicable).

As held by the Missouri Court of Appeals, the Commission can only fulfill its responsibility under Section 393.170 to protect the public interest by addressing "conditions existing at the time the power is exercised, because such interest is not static and changes over time." StopAquila.org v. Aquila, Inc., 180 SW3d 24, 35 (Mo App 2005). The Court further held that the statute requires "that a public hearing relating to the construction of each particular electric plant take place in the months before construction begins, so that current conditions, concerns and issues ... can be considered." Id at 37-38. The Court concluded that the statute does not "give the Commission the authority to grant a certificate of convenience and necessity for the construction of an electric plant without conducting a public hearing that is more or less contemporaneous with the request to construct such a facility." Id at 34. (Emphasis added).

The most reasonable interpretation of the statute accordingly limits utilities to seeking authority for generating units that they intend to begin to construct within the next two years. Likewise, the most reasonable interpretation of the statute would nullify a Commission order as to any generating unit for which construction does not commence within two years of issuance of the order. Absent such interpretations, utilities could seek approval of multiple generating units and then build them over the course of an unlimited period of time, without further Commission consideration of the purported propriety of and need for the unit based on contemporaneous facts and circumstances. Such unconstrained pre-approval would result in the same inadequate "toothless" after-the-fact prudence review in the rate case context that the Court of Appeals has observed would apply if there was no preapproval process at all. State ex rel Cass County v. PSC, 259 SW3d 544, 549-50 (Mo App 2008). The Court specifically rejected the notion that the Commission could somehow determine "that a specific power plant will be necessary or convenient for the public service far into the future." StopAquila.org v. Aquila, Inc., 180 SW3d 24, 34 (Mo App 2005).[1]

As held by the Court of Appeals, the statute establishes a two-year time limit and the Commission should review any plant to be constructed beyond that limit based on a

[1] Even though the Commission had erroneously decided that a company did not need to seek approval of plant to be built within its certificated area, due to the prior issuance of certificate, it did not question its jurisdiction over the company and its plant or its ability to exclude the costs from ratemaking. See 24 MoPSC NS 72, 79 (1980). Moreover, the Commission's decision seemed in part driven by the fact that the particular company had actually applied for approval after-the-fact and had thereby "placed the Commission in a position where a meaningful decision cannot be made." Id at 78.

new record. The statute does not allow approval of a 50-year construction plan, or a 10-year plan, or a 5-year plan. It allows approval of a two-year construction plan.

Dogwood has included language regarding separate approval of multiple generating units and the two-year time limit in the attached revised rulemaking proposal.

2. Whether separate CCNs should be required for substantial renovation or refurbishment of an existing unit that changes the principal fuel used, increases the capacity of the unit, extends the life of the unit, or appreciably changes the emissions, noise level, or traffic from the plant.

Yes, Section 393.170 should be interpreted as requiring advance Commission approval of major renovations of electric plant, and the rule should be revised consistent with that interpretation.

In its comments regarding Dogwood's Rulemaking Petition in Case No. EX-2014-0205, Staff suggested the Commission should attribute some significance in the Court of Appeal's passing reference to "new" construction in StopAquila.org v. Aquila, Inc., 180 SW3d 24, 39 (Mo App 2005). But the statute does not use the word "new" and any construction that is underway is "new" construction. Only completed construction is eventually not "new". The question remains, how best to interpret the word "construction" as it is used in Section 393.170 in order to protect the public interest.

As Dogwood pointed out in its Rulemaking Petition, public utilities are subject to the Missouri prevailing wage statutes, Sections 290.210 to 290.340. Under those statutes, public utilities must pay prevailing wages on "construction" of public works, "exclusive of "maintenance work". See Sections 290.220-230. Such "public works" "includes any work done directly by any public utility company when performed by it pursuant to the order of the public service commission." See Section 290.210(11). Further, "construction" includes "construction, reconstruction, improvement, enlargement, alteration, painting and decorating, or major repair". See Section 290.210(3). "Maintenance work" is defined as "the repair, but not the replacement, of existing facilities when the size, type or extent of the existing facilities is not thereby changed or increased." See Section 290.210(7).

The Missouri Supreme Court has held that a broad definition of construction accomplishes the remedial purposes of the prevailing wage statutes, namely prevention of substandard wages. Utility Service Co., Inc. v. Department of Labor and Industrial Relations, 331 SW3d 654, 658- 660 (Mo. 2011). The Court held that "any work that is encompassed in the plain meaning of the language defining 'construction' under section 290.210(1) is work that requires payment of prevailing wages, regardless of whether the work changes the size, type or extent of an existing facility." Id. The Court noted a prior holding that struck down a regulation purporting to use a 20% demarcation point to differentiate between construction and maintenance, because "the legislature did not intend a test for magnitude be used." Id. citing State Dept of Labor v Public Utilities of City of Springfield, 910 SW2d 737 (Mo App 1995). The Court discussed the expansive meaning of the terms "reconstruct", "improvement", "alteration", and "major repairs" in the definition of "construction", in finding that the work at issue was "construction" but not "maintenance work".

The same broad definition of "construction" should apply in the context of Section 393.170, which is also a remedial statute, enacted to protect the public interest from abuse of monopoly utility power. See, e.g., State ex rel Laundry Inc v PSC, 34 SW2d 37 (Mo 1931)(PSC laws are remedial and must be liberally construed). Such a statute "should be construed so as to meet the ... evil which it was designed to remedy." Utility Service Co at 658. "Doubts about the applicability of a remedial statute are resolved in favor of applying the statute." Id.

The courts have held that the definition of "construction" found in the prevailing wage statutes should be applied to other statutes using the word "construction" in connection with entities that are subject to prevailing wage requirements. Hadel v. Board of Education of School District of Springfield, 990 SW2d 107, 112-13 (Mo. App. 1999). Staff should re-examine this opinion, and its application of the definition of "construction" in Section 290.210 to interpret another statute to distinguish between "construction" and "maintenance". Likewise, the Staff should closely examine the Supreme Court opinion in Utilities Service Co. discussed above. Notwithstanding the unique status of the Commission discussed by Staff in its Response in Case No. EX-2014-0205, the statutes governing the Commission are not to be interpreted in a vacuum and must be construed in light of other pertinent statutes, including the prevailing wage statutes which expressly govern utility construction projects that are subject to public service commission supervision. See, e.g. State ex rel Smithco Transport Co. v. PSC, 316 SW2d 6, 12-13 (Mo. 1958).

Dogwood also pointed out in its Rulemaking Petition that in Warren Davis Properties, LLC v. United Fire & Casualty Co., 111SW3d 515, 522 (Mo App 2005), the court held in the context of an insurance policy, that "construing the reasonable definition of 'construction' in favor of the insured, we find that activities encompassing the renovation of a building are construction." Given that an insured has a choice as to whether to buy their insurance policy, the public that generally must take service from a monopoly utility deserves at least the same degree of favor in interpretation of the scope of Section 393.170.

The regulated utilities currently have environmental compliance projects in their plans with price tags much larger than some of the relatively minor renewable energy projects Staff mentioned in its response to Dogwood's Rulemaking Petition as examples of recent (and appropriate) applications under Section 393.170. Protection of the public interest calls for examination of such major retrofit projects as compared to alternatives including plant retirement. Such retrofit projects qualify as "construction" under Section 393.170.

By using the same definitions of "construction" and "maintenance work" to interpret Section 393.170 as are set forth in Section 290.210, the Commission would provide full effect to the prevailing wage statutes and much clearer guidance to the regulated utilities. Construction projects approved pursuant to Section 393.170 would be subject to prevailing wage under Section 290.210(11) as "work done directly by any public utility when performed by it pursuant to the order of the public service commission." Likewise, the utilities could rely on their experience in complying with the prevailing wage statutes as well as all applicable court opinions in evaluating whether a project should be submitted for Commission approval under Section 393.170. Such uniformity and guidance as to statutory application is particularly critical, given the ultimate penalty for failure to seek required advance approval of electric plant construction under Section 393.170 is dismantling the facility. StopAquila.org v. Aquila, Inc., 180 SW3d 24, 34 (Mo App 2005).

Dogwood's attached rule revision proposal addresses this point.

3. Whether separate CCNs should be required for the construction of a generating unit in a state other than Missouri that will be treated in rate base and as an operating expense for the purpose of setting Missouri rates for Missouri native load.

Yes, any electric plant construction activity by a Missouri regulated utility should be examined pursuant to Section 393.170. Rule 3.105 should be revised consistent with that interpretation.

After conducting additional research, Dogwood has revised its rulemaking proposal on this point. Rather than engage in an analysis of ratemaking/rate base intent as called for in Dogwood's initial proposal, the determinative question for the Commission should be whether the electric plant construction activity is to be conducted by or for a Missouri regulated utility.

The Commission has jurisdiction over companies engaged in the business of providing electricity to the public. Section 386.250 grants such jurisdiction not only over the activity of providing electricity within the state, but also over the public service activities of the entity as a whole. See, e.g. State ex rel. and to Use of Cirese v. PSC, 178 SW2d 788, 790 (Mo. App. 1944), see also Section 386.020 (definitions of electric plant, electric corporation, public utility, and service). The PSC has authority to examine all "methods, practices, regulation and property employed by public utilities." State ex rel Laclede Gas v. PSC, 600 S@2d 222, 228 (Mo App 1980). The PSC statutes "provide a complete scheme for the supervisions and regulation of all the activities of an electric utility by the commission." PSC v. Kansas City Power, 31 SW2d 67, 71 (Mo 1930). The exception to the rule would be federally regulated interstate commerce activities, unless also permitted by Congress, see Section 386.030.

A holding company has the option of segregating public utility activities state-by-state by having separate subsidiaries. But if a single company that is subject to Commission regulation chooses to operate and/or have facilities in multiple states, it must subject all those activities to Commission supervision pursuant to Section 393.170. Such supervision is not unlawful, as KCP&L argued in its comments in Case No. EX-2014-0205.

The Commission and Staff have previously endorsed this approach regarding the disposal of assets under Section 393.190. In Case No. EO-2004-0108, the Commission held that it had jurisdiction over AmerenUE's proposal to sell its retail natural gas and electric operations in Illinois to an affiliate. The Commission based its conclusion on AmerenUE's status as an electric corporation and public utility subject to Commission regulation under Chapters 386 and 393. Regarding Section 393.190, the Commission held that "the cited statute does not make any distinction as to the location of the property [to be sold], whether in Missouri or elsewhere." Further, the Commission held that Section 393.190 "makes a distinction that turns on whether or not the property in question is 'necessary or useful' to the utility in the performance of its duties to the public." The Commission found that the proposed transaction had both direct and indirect impacts on Missouri operations, including reduction of native load. See In the Matter of the Application of Union Electric Company Doing Business as AmerenUE, for an Order Authorizing the Sale, Transfer and Assignment of Certain Assets, Real Estate, Leased Property, Easement and Contractual Agreements to Central Illinois Public Service Company, Doing Business as AmerenCIPS, and in Connection Therewith, Certain Other Related Transactions, Case No. EO-2004-0108, 13 MoPSC 3d 266, 289-90 (2005).

In that case, when Ameren raised questions about the Commission's jurisdiction, the Staff strongly disagreed, and pointed to prior example of Ameren and KCP&L assets located in other states over which the Commission had asserted jurisdiction. Specifically, Staff pointed to Case Nos. EM-92-225, EM-92-253, EM-91-213, and EF-87-29. See Staff Reply Brief, p. 8-9, Case No. EO-2004-0108. Staff argued for a broad interpretation of Commission jurisdiction, "to protect the public from self-interested actions of a monopoly utility company." Id at 10-11.

One of the issues to be considered by the Commission in examining the proposed actions in another state of one of the utilities that it regulates is whether there would be a detrimental impact on Missouri ratepayers. See, e.g. In the Matter of the Application of The Kansas Power and Light Company and KCA Corporation for Approval of the Acquisition of All Classes of the Capital Stock of Kansas Gas and Electric Company, to Merge with Kansas Gas and Electric Company, to Issue Stock, and Incur Debt Obligations, Case No. EM-91-213, 1 MoPSC3d 150, 159 (1991).

If a Missouri-regulated utility proposes to construct an electric generating unit in another state, such a project could certainly impose detrimental impacts on Missouri ratepayers. An imprudent project could impact the utility's overall ability to render safe and adequate service, could increase rates, could increase administrative and capital costs, or have other impacts in Missouri. Id. Additionally, even if there is no initial plan to include part or all of the plant in Missouri rate base for ratemaking purposes, such plans could change at any time and the Commission would be faced with a post-construction issue contrary to the provisions of Section 393.170. See State ex rel Cass County v. PSC, 259 SW3d 544, 549-50 (Mo App 2008).

The Commission has also previously authorized financing of construction in other states under Section 393.190. In Case No. EF-2006-0263, the Commission authorized Empire to issue bonds to fund, among other things, "construction associated with the Plum Point Power Plant" in Arkansas. See Order Granting Application, Case No. EF-2006-0263 (May 5, 2006). Although Empire had not directly referenced the Plum Point plant in its application, Staff discovered in its review of financial statements that Empire intended to use the proceeds for that project and recommended the approval language that the Commission included in its order regarding that plant.

And the Commission has authorized construction accounting for plant in other states. See, e.g, Case No. EO-2010-0262 (regarding Plum Point again).

The Commission has jurisdiction under Chapters 386 and 393 over an electrical corporation and its construction, acquisition, financing, and other activities, including such activities outside the state. These statutes make plain that major decisions of a utility are to be reviewed in advance, notwithstanding its general managerial discretion (that remains subject to after-the-fact review in ratemaking cases). Thus, under Section 393.170, the Commission has jurisdiction and responsibility to examine in advance any major activities, such as construction projects proposed by a Missouri utility in another state, to protect Missouri ratepayers. While such projects may also be examined by the regulatory commission in the other state, that is a product of the utility choosing to have multi-state activities under a single entity. But notably the FERC generally does not have authority over generation facilities. See 16 USC 824.

For purposes of pre-approval of construction, consideration should be given both to overall impact on the regulated utility and its ability to serve the public (i.e. prudence), as well as potential rate impacts on Missouri ratepayers. Even if the utility has no current plans to put a plant to be built in another state into its Missouri rate base, if the project is unnecessary or beyond the means of the utility it could nonetheless have a negative impact in this state.

Based on the foregoing, Dogwood has revised its rulemaking proposal to address all electric plant construction activities of a Missouri regulated utility, regardless of location.

4. Whether separate CCNs should be required to acquire electric plant built by others in Missouri, or another state, that will be treated in rate base and as an operating expense for the purpose of setting Missouri rates for Missouri native load.

Yes, if a utility engages another entity to build electric plant on a turnkey basis, such a situation should be considered construction by the utility subject to Section 393.170. A utility should not be able to evade regulatory scrutiny of a construction project by means of a step-transaction.

However, it may be a better approach to consider acquisitions of electric plant that have actually been used by others under separate statutes. For example, Section 393.190.1 requires advance Commission approval of any form of transaction regarding electric “works or systems”, stating that an electric corporation shall not “by any means, direct or indirect, merge or consolidate such works or system, or franchises, or any part thereof, with any other corporation person or public utility, without having first secured from the commission an order authorizing it to do so.” Likewise, Sections 393.190-393.220 provide the Commission with jurisdiction over all means of financing major projects and transactions. Even if the Commission were to find that turn-key acquisitions are not subject to Section 393.170, such acquisitions would still be subject to approval under Sections 393.190-393.220.

Dogwood has revised its proposal regarding rule 3.105 consistent with these comments. It also appears that rule 3.110 and/or 3.115 should be clarified, to make plain that acquisitions of a scale smaller than total merger of companies, such as acquisition of a single generating unit, also require advance approval from the Commission. The rationale for Commission review remains the same: an ill-advised major transaction or project poses substantial risks for Missouri ratepayers. For example, the title of 3.115 could be changed to “Filing Requirements for Electric Utility Applications to Merge, Consolidate or Acquire Electric Plant”. Changes could be made in the text of the rule as well to address plant acquisitions, including incorporation of competitive bidding requirements for the reasons stated below.

5. Whether competitive bidding should be required for renovation or construction of electric plant.

Yes, the Commission should make sure that its rule requires companies to substantiate their proposed projects, based on alternatives identified by fair and open competitive bidding procedures. The Commission would not be adequately informed as to the propriety of a proposed project as compared to alternative solutions without such information. Such rules are already in place in other states, sometimes for all acquisitions and sometimes for affiliate transactions. See, e.g., Arkansas (126 03 CARR 017), Connecticut (RCSA 16-244c-2 et seq), Iowa (199 IAC 40.1(476) et seq), Maryland (COMAR 20.40.02.01 et seq; 20.52.04.01 et seq)), New Jersey (NJAC 14:4-3.3), Oklahoma (OAC 165.35-34-1 et seq), Pennsylvania (52 PC 57.34), and Texas (16 TAC 25.272 et seq). The Indiana Legislature recently added requirements for competitive bidding to its preapproval statute. See HB 1162 (2014) amending IC 8-1-8.5-5. See also Iowa Code 476.53.

When taxpayer dollars are being spent, the State of Missouri employs competitive bidding procedures to assure that sound fiscal management rules the day, rather than internal bias or external favoritism. See, e.g. 34.040 RSMo. The Commission follows such procedures itself. Improper influence, whether from affiliated relationships or less formal connections, is an insidious thing – it can be hard to identify, hard to prove, and hard to undo. Hence, monopoly utilities should also be required to use such competitive bidding procedures when evaluating major capital projects. The risks of harm to the public are great, given the large dollar amounts involved in electric plant projects.

<u>The Commission's IRP and affiliate transaction rules already contain provisions requiring competitive bidding.</u> Rule 22.070(6)(E) requires that a regulated utility's IRP

implementation plan include “a description of adequate competitive procurement policies to be used in the acquisition and development of supply-side resources.” (See also rule 20.015(3)(A) regarding competitive bidding for affiliate transactions). Because the utilities are to describe in their IRPs competitive procurement procedures that are “to be used”, competitive bidding should be expressly identified in rule 3.105 as a component of an application for approval of supply-side resources under Section 393.170.

Attached hereto is report from the Electric Power Supply Association from 2004 discussing the benefits of competitive bidding, which Dogwood previously submitted in Case No. AO-2011-0332. While outside the scope of rule 3.105 and Section 393.170, as indicated in the report the Commission should also consider exercising its general supervisory and rulemaking authority to require the use of competitive bidding in purchase power situations.

6. Any other issue that should be brought to the attention of the Commission.

Dogwood continues to believe that affording the Commission the express option of involving a third party monitor, at utility expense, makes sense. Several of the other states identified in response to question 5 have provisions for third party monitors in their regulations. Accordingly, Dogwood has left that language in its proposal.

Staff may be overloaded at a particular time, or find that it lacks the necessary expertise to evaluate a particular transaction. Having the option to involve a neutral third party just adds to the Commission's toolbox. Dogwood does not propose to delegate final decision-making authority to any third party.

Conclusion

Dogwood appreciates this opportunity to comment. It has been advocating for increased advance scrutiny of electric plant projects and greater use of competitive procurement measures for many years now. Dogwood looks forward to working with Staff in this matter to develop a final rule proposal to submit to the Commission.

CURTIS, HEINZ,
GARRETT & O'KEEFE, P.C.

Carl J. Lumley, #32869
130 S. Bemiston, Suite 200
Clayton, Missouri 63105
(314) 725-8788
(314) 725-8789 (Fax)
clumley@lawfirmemail.com

Attorneys for Dogwood Energy, LLC

CERTIFICATE OF SERVICE

A true and correct copy of the foregoing was served upon the parties identified on the attached service list on this 12 day of June, 2014, by email transmission.

Office of Public Counsel
Governor Office Building, Suite 650
P.O. Box 2230
Jefferson City, Missouri 65102

Office of General Counsel
Missouri Public Service Commission
200 Madison Street
P.O. Box 360
Jefferson City, Missouri 65102

Dean Cooper
Brydon Swearingen England
312 E. Capitol Avenue
P.O. Box 456
Jefferson City, MO 65102

Kansas City Power & Light Company
Roger Steiner
P.O. Box 418679
Kansas City, MO 64141-9679

James B. Lowery
Suite 200, City Centre Building
111 South Ninth St
Columbia Mo 65205

4 Mo. Code of State Regulations 240-3.105

4 CSR 240-3.105 Filing Requirements for Electric Utility Applications for Certificates of Convenience and Necessity

PURPOSE: Applications to the commission requesting that the commission grant a certificate of convenience and necessity must meet the requirements of this rule. As noted in the rule, additional requirements pertaining to such applications are set forth in 4 CSR 240-2.060(1).

(1) In addition to the requirements of 4 CSR 240-2.060(1), applications by an electric utility for a certificate of convenience and necessity pursuant to Section 393.170 RSMo authorizing operation in a service area or construction of electric plant shall include:

(A) If the application is for a service area--

1. A statement as to the same or similar utility service, regulated and nonregulated, available in the area requested;

2. If there are ten (10) or more residents or landowners, the name and address of no fewer than ten (10) persons residing in the proposed service area or of no fewer than ten (10) landowners in the event there are no residences in the area, or, if there are fewer than ten (10) residents or landowners, the name and address of all residents and landowners;

3. The legal description of the area to be certificated;

4. A plat drawn to a scale of one-half inch (1/2") to the mile on maps comparable to county highway maps issued by the Missouri Department of Transportation or a plat drawn to a scale of two thousand feet (2,000') to the inch; and

5. A feasibility study containing plans and specifications for the utility system and estimated cost of the construction of the utility system during the first three (3) years of construction; plans for financing; proposed rates and charges and an estimate of the number of customers, revenues and expenses during the first three (3) years of operations;

(B) If the application is for electrical transmission lines, gas transmission lines or electrical production facilities--

1. A description of the route of construction and a list of all electric and telephone lines of regulated and nonregulated utilities, railroad tracks or any underground facility, as defined in section 319.015, RSMo, which the proposed construction will cross;

2. The plans and specifications for the complete construction project and estimated cost of the construction project or a statement of the reasons the information is currently unavailable and a date when it will be furnished; ~~and~~

3. Plans for financing; and

4. Verification of intent that construction of the lines or facilities will commence within two years from the date of Commission approval and will be completed in a diligent manner thereafter.

(C) When no evidence of approval of the affected governmental bodies is necessary, a statement to that effect;

(D) When approval of the affected governmental bodies is required, evidence must be provided as follows:

1. When consent or franchise by a city or county is required, approval shall be shown by a certified copy of the document granting the consent or franchise, or an affidavit of the applicant that consent has been acquired; and

2. A certified copy of the required approval of other governmental agencies; and

(E) The facts showing that the granting of the application is required by the public convenience and necessity, including but not limited to the projected benefits, risks and costs of the electric plant described in the application as compared to the projected benefits, risks and costs of all reasonably available alternative solutions, including but not limited to retirement of existing electric plant. The costs of the electric plant described in the application and such alternative solutions shall be identified using open, transparent, fair, and nondiscriminatory competitive bidding procedures. The commission may appoint an independent and unbiased monitor at the expense of the electric utility to evaluate such costs and supporting information prior to ruling on the application.

(2) If any of the items required under this rule are unavailable at the time the application is filed, they shall be furnished prior to the granting of the authority sought.

(3) For purposes of Section 393.170 and this rule, "electric plant" shall include facilities to be owned or leased by an electrical corporation whose rates are regulated by the Commission regardless of location, and "construction" of electric plant shall include acquisition by capital lease or other means of facilities constructed by others for the regulated electrical corporation and any construction subject to the prevailing wage requirements of Sections 290.210 et seq RSMo. but shall not include "maintenance work" as defined in such statutes.

(4) Multiple transmission lines and/or production facilities may be considered in a single application, but an approval order will be null and void as to any distinct line, facility, phase or project for which construction is not commenced within two years of issuance of the order and diligently completed.

AUTHORITY: section 386.250, RSMo 2000. Original rule filed Aug. 16, 2002, effective April 30, 2003.

Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996.

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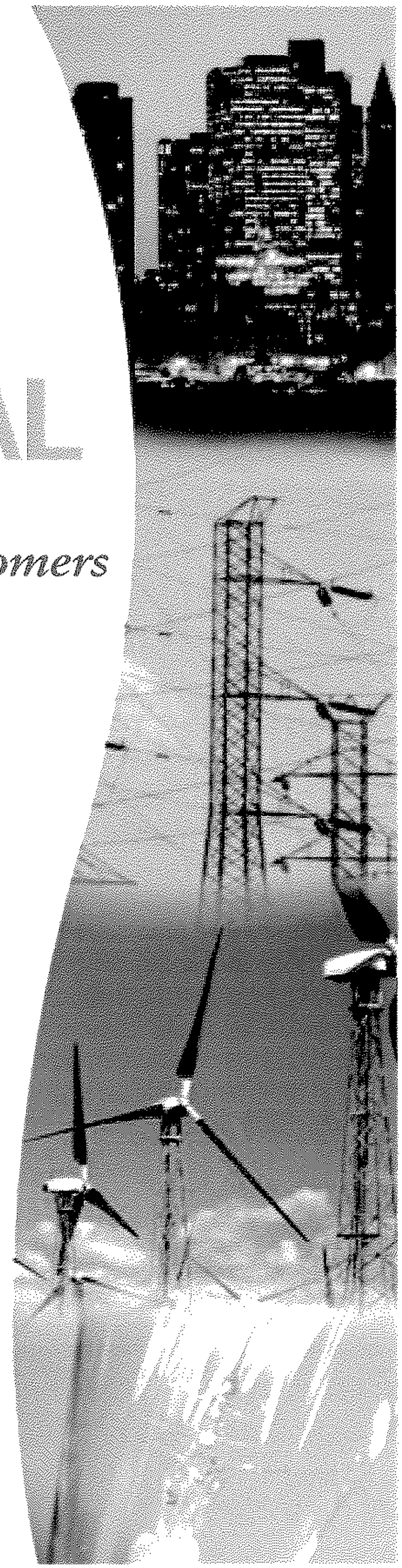

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Prepared For:

Electric Power Supply Association
1401 New York Avenue, NW, 11th Floor
Washington, D.C. 20005
Telephone: (202) 628-8200
Fax: (202) 628-8260
Web site: www.epsa.org

Prepared By:

Boston Pacific Company, Inc.
1100 New York Avenue, NW, Suite 490 East
Washington, D.C. 20005
Telephone: (202) 296-5520
Fax: (202) 296-5531
Web site: www.bostonpacific.com

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FOREWORD *by EPSA*

The Electric Power Supply Association (EPSA) is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for nearly 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving global power markets. EPSA seeks to bring the benefits of competition to all power customers. EPSA supports the continued formation of regional transmission organizations (RTOs), including essential features such as independent administration of the transmission system, real-time and day-ahead energy markets, and capacity markets. In addition, but not as a substitute for RTO markets, EPSA believes that all parties, and customers in particular, benefit from competitive solicitations for longer-term power purchases that are designed to be fair, accurate, and transparent. As such, it is useful to establish guidelines for the proper conduct of competitive solicitations, particularly in areas where RTOs have yet to be formed. This reference document is intended to assist policy-makers in establishing guidelines to ensure that competitive solicitations provide the best possible deal for electricity consumers.

FOREWORD *by Boston Pacific Company, Inc.*

Boston Pacific Company, Inc. is an energy consulting and investment services firm. Our clients include competitive power suppliers, electric utilities, electric and gas marketers, gas pipeline companies, trade associations, government agencies, public service commissions and energy consumers. This guidebook is based on our experience working in engagements on competitive solicitations conducted in primarily non-RTO areas, and in RTO areas, as well. It reflects the lessons we learned from these engagements, and is intended to help all participants in the competitive solicitation process get the process right. Getting the process right means ensuring that the competitive solicitation, from start to finish, is a credible process that results in the best possible deal for electric utility customers in terms of price, risk, reliability and environmental performance.

EXECUTIVE *Summary*

Although federal regulators have rightfully focused much of their effort in recent years on properly structuring shorter-term spot markets for energy and capacity under the auspices of independent regional transmission organizations (RTOs), the design of longer-term bilateral markets is equally important. Longer-term markets, in which power is procured on a multi-month, yearly, or multi-year basis, could—and in some regions do—satisfy 85 percent to 90 percent of power needs. Along with shorter-term markets, these markets provide the necessary price signals for development of new resources. And, because they involve longer-term commitments to sell power, they provide a significant opportunity to justify major capital investments in power plants and related infrastructure. Consumers benefit when suppliers take advantage of these opportunities by building new infrastructure, which both intensifies competition and increases reliability.

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To many, the design of longer-term markets is synonymous with the design of competitive solicitations, which range from price-only auctions to more extensive requests for proposals (RFPs) that evaluate bids with respect to a long list of price and non-price criteria.[1] This guidebook is based on lessons learned from hands-on experience with competitive solicitations. It is meant to be a useful resource for all those charged with designing, implementing and/or monitoring these solicitations.

First and foremost, the goal of competitive solicitations is to evaluate a full range of resources in the wholesale marketplace to obtain the best possible deal for electric utility customers. In this specific sense, competitive solicitations, when conducted in a fair, accurate and transparent manner, are an important tool at both the state and federal levels for determining the

[1] Short-term markets such as day-ahead and real-time spot markets also use bid-based competitive solicitation formats; however, the focus of the guidebook is on longer-term competitive solicitations.

prudence of utility power purchase and investment decisions and allaying concerns about affiliate bias.

It is essential that the solicitation be credible to all parties, including electric customers, regulators, the utility buyer, and suppliers. The primary means of ensuring credibility are the use of (a) a collaborative process that adopts consensus-based solicitation rules upfront and (b) an independent, third-party monitor. The collaborative process includes specific opportunities for significant input from all participants early on, thereby streamlining the overall solicitation design, especially in contrast to full litigation. An independent, third-party monitor can help facilitate the collaborative process and oversee the solicitation itself.

The purpose of the independent monitor is to provide assurances to all those involved in the solicitation that the process was fair, transparent and accurate.

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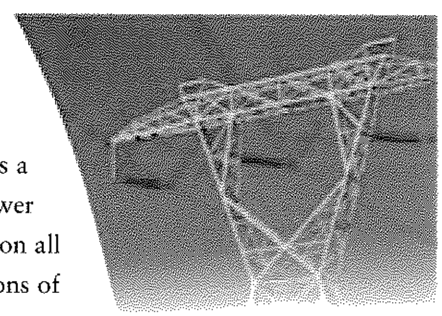
Once measures are in place to assure a credible solicitation, the format and product types to be solicited must be decided. Price-only auctions are best for markets in which there are standardized products, meaning that all aspects of the non-price bid evaluation can be settled beforehand. This, of course, adds greatly to transparency since only a single factor (price) determines who wins the solicitation. Price-only RFPs also are issued for standard products such as a share of full requirements service or blocks of power (e.g., 100 MW of firm power for 16 hours a day on all weekdays). Many RFPs, however, involve evaluations of (and allow variations in) a full range of price and non-price factors. Asset-backed or unit-contingent power is one example of a product solicited through these more complicated RFPs. Generally, auctions and RFPs conducted in the context of a well-functioning RTO can take much less time to start and run more smoothly than those in non-RTO areas.



Within a competitive solicitation, there are at least six key issues that need to be addressed to fairly and accurately evaluate bids:

- the principle of ***comparability*** means that all proposals should meet the same requirements and be evaluated under the same standards;
- ***transmission assessments*** for bidders during a solicitation should include an opportunity for any bidder to receive a timely and fair estimate of what it would take to become a network resource;
- when assessing ***cost-plus offers***, the evaluation should explicitly take into account the greater risk that these offers impose on customers as compared to pay-for-performance bids;
- financial theory supports using the annuity method when comparing offers of ***unequal lives***, and this should be at least one approach used during any bid evaluation;
- ***creditworthiness*** is a legitimate concern; however, collateral requirements must be set comparably and fairly for all parties, and contractual alternatives to collateral must be considered; and,
- in determining whether to assess a ***balance sheet penalty***, regulators should take the perspective of the utility customer, ask for evidence that a balance sheet effect actually occurred, and if the penalty is assessed, then ensure it is accurately calculated.

Ideally, all six of these issues should be settled during the collaborative process, along with all of the other solicitation rules and conditions, before the solicitation takes place. Doing so minimizes the potential for objections later on in the solicitation. Most important, settling these issues provides clarity to all stakeholders about the criteria that will be used to evaluate the bids.

All decisions for the solicitation should be guided by one goal: to obtain the best possible deal for customers by credibly evaluating the full range of resource alternatives offered.

Regardless of the solicitation format used, the product types solicited, or the approach to evaluation chosen, all decisions for the solicitation should be guided by one goal: to obtain the best possible deal for customers by *credibly* evaluating the full range of resource alternatives offered in the wholesale power market.

INTRODUCTION

I. INTRODUCTION: *The Importance of and Role for Competitive Solicitations*

In recent years, the focus on designing shorter-term power markets has overshadowed the importance of properly structuring longer-term markets. Longer-term power markets, in which power is procured on a multi-month to multi-year basis, are crucial to providing the necessary price signals for suppliers to develop new resources to meet a substantial portion of our future power needs. Because a significant amount of power can be procured for lengthy periods of time, mistakes in the design of longer-term markets can be costly to utility customers.

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For example, a long-term procurement decision that had substantial consequences in terms of cost, risk, and environmental performance was the construction of nuclear and other large baseload power plants during the 1970s and 1980s. The Federal Energy Regulatory Commission (FERC) reported that,

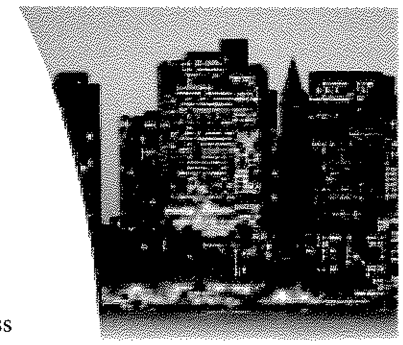
> "...expensive large baseload plants for which there was little or no demand, came onto the market or were in the process of being constructed. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25 percent after adjusting for general inflation. Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86 percent after adjusting for inflation."[2]

Again, the potential for significant, adverse consequences from poorly made procurement decisions make it especially important that long-term markets be properly designed. To many, the design of longer-term markets is synonymous with the design of competitive solicitations, which range from price-only auctions to more extensive requests for proposals (RFPs) that

[2] FERC Order 888 at p. 14.

evaluate bids with respect to a long list of price and non-price criteria. This guidebook is based on lessons learned from hands-on experience and is meant to be a useful resource for all those charged with designing, implementing, and monitoring competitive solicitations.

A A Tool For Modernizing State Prudence Review



By requiring utilities to demonstrate the prudence of their investment and procurement decisions, state regulatory commissions attempt to ensure that their energy consumers get the best possible deal on electricity in terms of price, risk, reliability, and environmental performance. The heart of prudence has always been a reasonable decision-making process in which all alternatives are evaluated side-by-side with information known and knowable at the time of the decision. This definition of prudence is reflected in a ruling in *Gulf States Utilities Company v. Louisiana Public Service Commission* by the Louisiana Supreme Court, which states that:

> Although there is no single formulation sufficient to express constitutional, statutory, or judicially derived standards for determining how much of a utility's investment in a particular plant should be included within its rate base, one of the principles used by ratemaking bodies and courts to make such a determination is the prudent investment standard... That is, the utility must demonstrate that it 'went through a reasonable decision-making process to arrive at a course of action and, given the facts as they were or should have been known at the time, responded in a reasonable manner.' *Re Cambridge Electric Light Co., 86 P.U.R. 4th 574 (Mass. D.P.U. 1983)...* the focus in a prudence inquiry is not whether a decision produced a favorable or unfavorable result, but rather, whether the process leading to the decision was a logical one, and whether the utility company reasonably relied on information and planning techniques known or knowable at the time. *Metzenbaum v. Columbia Gas Transmission Corp., Opinion No. 25, 4 FERC 161,277.*

An electric utility can use competitive solicitations to demonstrate prudence by showing that it used a reasonable decision-making process, meaning that it fairly evaluated the full range of alternatives. Indeed, in today's market, because so many alternatives are proposed by credible parties other than the regulated utility, and include more than just large-scale conventional power plants, competitive solicitations are essential to ensure that the utility has evaluated the full range of both utility and non-utility alternatives. In addition, many of these alternatives are from suppliers who, in contrast to traditional utility cost-plus offers, are willing to guarantee the customer benefits that they promise in their proposals, so the evaluation must take this customer risk-protection into account.

Using competitive solicitations to demonstrate prudence also can provide regulatory certainty to the utility. For example, if the solicitation meets certain standards, the state commission could establish a rebuttable presumption that the process results in a prudent investment or procurement decision; in any subsequent proceeding, the rebuttable presumption would shift the burden of proof away from the utility to intervenors. With this in place, the commission could generally review the solicitation process in a much shorter time. This determination of prudence would remove the risk that the utility would not be able to recover costs that were incurred as a result of the contracts signed through the competitive solicitation.

Regulatory certainty also is enhanced for competitive power suppliers in two ways. First, a quick review period minimizes the market risks to suppliers of keeping bids open for extended periods of time. Second, a determination of prudence obviates the need for a "regulatory out" clause in the Power Purchase Agreement (PPA).

B Allaying Concerns About Affiliate Bias

At the Federal Energy Regulatory Commission, a properly designed competitive solicitation can play a central role in allaying concerns about affiliate bias. In *Boston Edison Company Re: Edgar Electric Energy Company* 55 FERC ƒ 61,382 (1991), FERC set forth three non-exclusive ways a utility could demonstrate the lack of affiliate abuse. One way is to offer evidence of "direct head-to-head competition," which means the utility uses some form of competition solicitation.[3] If a utility chooses this route, then the commission "seeks assurance" that (1) the solicitation process did not favor the affiliate; (2) the analysis of the bids or responses did not favor the affiliate; and, (3) the affiliate was chosen based on a reasonable combination of price and non-price factors. Moreover, if an affiliate is chosen and is *not* the least-cost option, the applicant must explain why that selection was made.[4] The concern here is primarily with affiliate abuse—when a utility unduly favors its affiliate's offer over other offers to the detriment of consumers. The *Edgar* precedent is useful because it establishes a threshold standard that a utility must meet when conducting competitive solicitations to demonstrate a lack of affiliate abuse. Getting longer-term market design right by conducting a fair, transparent and accurate competitive solicitation is essential to meeting FERC's *Edgar* standard.

C Overview Of This Report

Clearly, competitive solicitations can play a central role in evaluating resource alternatives so as to get the best possible deal for utility customers. At the state level, they can assist in modernizing the prudence review standard, and at the federal level, they meet the requirements of the *Edgar* standard for demonstrating the lack of affiliate abuse. But, what are the essential elements of a competitive solicitation? Section II (Ensuring a Credible Solicitation) examines the key elements that ensure the solicitation process is fair and credible, which include the use of the collaborative process and an independent, third-party monitor. Section III (Choosing a Solicitation Format and Product Type) describes different solicitation formats and product types. Section IV (Fair and Accurate Bid Evaluations) reviews important evaluative factors used in a competitive solicitation. The conclusion, Section V, emphasizes that accurate, credible, and transparent competitive solicitations ensure that customers get the best possible deal on electricity in terms of price, risk, reliability and environmental performance. Finally, three appendices delve deeper into technical details.

[3] *See Boston Edison Company Re: Edgar Electric Energy Company* 55 FERC ¶ 61,382 (1991) (Edgar).
[4] *Id.*

A CREDIBLE SOLICITATION

II. ENSURING a Credible Solicitation

Above all else, competitive solicitations must be credible to all. This can be achieved primarily through the use of (1) a collaborative process and (2) an independent, third-party monitor. The loss of credibility due to affiliate abuse or other deficiencies in the procurement process tends to "chill the market" because competitive suppliers will not submit proposals if there is a perception that the proposals will not be evaluated objectively.[5]

A Collaborative Process

One approach to establishing credibility in the solicitation is called the collaborative process. The intent is that a full consensus can be achieved during a collaborative process on most issues with respect to the solicitation, such as the amount and type of power to be procured and the evaluation criteria to be used. This process has three key steps: (a) the local utility submits proposed approaches to all aspects of the solicitation, including the definition of product types and bid evaluation criteria; (b) a series of multi-day, commission-facilitated collaborative meetings are held that allow for significant stakeholder input on the utility proposals; and, (c) the state commission promptly resolves outstanding issues that are not resolved within a specified time frame.

To illustrate the use of a collaborative process for an RFP, here are eight recommended steps:

1. The state commission chooses a monitor (ideally an independent, third-party monitor) to facilitate the collaborative process or work in conjunction with the commission staff to facilitate the process;
2. The utility submits its forecasted resource requirements to the collaborative process;
3. A multi-day collaborative meeting allows for an open discussion with the goal of gaining consensus on those resource requirements among market participants, commission staff and the utility. These

[5] Preparation of legitimate bids for long-term supplies typically cost \$50,000-\$75,000 to prepare, and competitive suppliers take these costs into consideration when deciding whether to bid.

estimates are key to defining the amount of power and types of products to solicit;

4. If consensus is reached, the resource requirement phase is over. If consensus is not reached, the independent, third-party monitor or staff would submit a report to the commission with recommendations on unresolved resource requirement issues. Other participants in the collaborative process also may file comments. The commission promptly resolves outstanding issues;
5. Next, the utility submits a draft solicitation package to the collaborative process;
6. The draft solicitation package provides the basis for another multi-day meeting in the collaborative process. These collaborative meetings would address issues such as bidder qualifications, the terms of a Model PPA if one is used, bid evaluation techniques and criteria, etc.;
7. If consensus is reached, the RFP design phase is over. If not, the independent, third-party monitor and/or commission staff reports to the commission with recommendations and the commission again settles any unresolved issues. Other participants also file comments, and the state commission promptly resolves outstanding issues; and,
8. The RFP is issued. While the local utility still is responsible for choosing the winning bids, the independent monitor has full access to all communication between the utility and bidders (most notably with the utility affiliate) through all phases of bid evaluation.

A process that incorporates stakeholder input can go a long way in building credibility. For a competitive solicitation in Arizona that addressed future needs for Arizona Public Service Company and Tucson Electric Power, the Independent Monitor wrote:

> in order for the Solicitation to attract wide participation, the process had to be accepted by participants as fair, open, and transparent. To achieve this, prospective bidders and interested persons who agreed to keep certain information confidential had the opportunity to review supporting data and draft documents in advance of the RFP... Many bidders and other interested persons provided comments to the util-

> ities, the Independent Monitor, or the Staff regarding the completeness or quality of the information provided. . . Bidders' conferences were held so that all interested parties had the opportunity to ask questions directly of the utilities as well as to identify deficiencies in the Solicitation documents or supporting data.[6]

A process that incorporates stakeholder input can go a long way in building credibility.

State commissions and utilities might be concerned that using a collaborative approach will encourage litigation and thus delay the solicitation itself. However, limiting the time for and the types of objections allowed in the collaborative process can mitigate these concerns. For example, in a recent Florida Public Service Commission (FPSC) order adopting changes to the rules governing utilities' procurement of new resources, the FPSC limited the amount of time RFP participants had to file objections, and limited the types of objections to specific allegations of violations of the rule.[7] Within 30 days of filing the objection, the FPSC would determine whether a rule violation occurred. Commenting on these changes, the FPSC stated that, "[w]e believe these changes will ensure that the objection process does not cause unnecessary delays to the RFP process. These changes should also provide greater clarity and certainty early on in the RFP process, and should help streamline and reduce the number of similar objections in the need determination process."[8]

B Independent, Third-Party Monitor

In addition to facilitating the collaborative process, an independent, third-party monitor also can add credibility by overseeing the entire solicitation process to ensure that there is no bias. For example, the monitor may perform an independent evaluation of the bids and monitor the communication between the utility and its affiliate.

[6] Independent Monitor's Final Report on Track B Solicitation to the Arizona Corporation Commission, Accion Group (May 27, 2003) at pgs. 6-7.
[7] *Order Adopting Changes to the Proposed Amendments of Rule 25-22.082, Florida Administrative Code* in Docket No. 020398-EQ (January 27, 2003) at p. 6.
[8] *Id.*

The benefit of an independent monitor is that the commission, staff, market participants and customers will have an extra pair of experienced eyes watching over the solicitation process. The monitor will know the mistakes that can be made and will possess the technical expertise to delve into the details of the utility's evaluation to determine any biases. Bidders gain peace of mind knowing that a fair and impartial entity is reviewing the details of the solicitation.

The decision on whether to use an independent monitor is driven primarily by three factors: (1) the desire to assist state regulatory commission staff with logistical and technical assistance; (2) whether a utility affiliate or the utility's self-build option participates in the solicitation; and (3) an assessment of the need to enhance confidence among stakeholders that the solicitation is credible.

For example, an Arizona Corporation Commission staff report on the process to be used for a competitive solicitation addressed two of the above points. Specifically, the report stated, "[t]o assist the Staff and to assure all parties to the Solicitation for power supplies that the process employed is conducted in a transparent, effective, efficient and equitable manner, an Independent Monitor will be appointed by the Staff of the Commission to oversee the conduct of the Solicitation."[9]

Of course, if an independent, third-party monitor is hired, it serves to complement, not replace, the state commission's staff. For example, in Arizona, a consultant was hired to work as part of a team with the commission staff, and in Maryland, a technical consultant was selected to assist in the bid evaluation phase of the solicitation.

Furthermore, an independent, third-party monitor would not supplant the utility's decision-making ability in the negotiation and signing of contracts—the utility still makes the decision on what resources to select. This is of particular concern for some utilities that fear that an independent third party or even commission staff would encroach on the utility's responsibility to determine the appropriateness of resource alternatives. Separately, commissions may be concerned over the costs of hiring an independent monitor. One way to defray these cost concerns is by assessing a non-refundable fee per bidder.

[9] Staff Report on Track B: Competitive Solicitation in Docket Nos. E-00000A-02-0051 et. al., (October 25, 2002) at p. 9.

III. CHOOSING A SOLICITATION *Format and Product Types*

Formats vary along a spectrum from price-only bid evaluations to bid evaluations based on a long list of price and non-price factors. Once measures are in place to ensure a credible solicitation, the format and product types to be solicited must be decided. The right solicitation format is primarily dictated by the type of product being solicited. For example, price-only auctions and RFPs are best for markets in which there are standardized products, meaning that all non-price factors can be settled beforehand. This, of course, adds greatly to transparency since only a single factor (price) determines who wins the solicitation. Many RFPs, however, involve evaluations of (and allow variations in) a full range of price and non-price factors. Asset-backed or unit-contingent power is a good example of a product solicited through such an RFP.

A Requests for Proposals (RFPs)

In many non-RTO areas, RFPs are often used to solicit unit-contingent power supply (i.e., the services of a specific power plant). RFPs allow bidders to submit proposals that include a variety of capacity sizes, start dates, term lengths, and pricing structures.[10] For instance, with respect to term lengths, a utility may want to solicit a mix of five-, ten- and fifteen-year contracts to match its evolving needs and spread its market risk over time.

The primary benefit of a unit-contingent RFP is that it enables competitive suppliers to provide generation under the same terms and conditions that the utility would apply to its owned generation.

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[10] In addition, RFPs allow demand-side management programs and renewable resources to compete as long as they offer comparable terms.

to-head comparison between a utility built power plant and one built by a competitive power supplier. Note, too, that competitive power suppliers who are marketers can provide unit-contingent power. Consumers benefit because the competition drives the utility and competitors to offer better, tangible deals in terms of lower price, lower risk, higher reliability and superior environmental performance. An added benefit is that suppliers can bid generation that is not yet on-line so that the number of competitors and the intensity of competition are increased.

A downside to unit-contingent RFPs is that they increase the difficulty of comparing proposals due to the differences in the bidders' offers. This may potentially lead to less transparent comparisons by allowing the evaluating party more discretion in the methods used to compare different aspects such as term lengths, availability guarantees, capacity sizes and timing. More discretion means more opportunity for bias. However, the lack of transparency can be mitigated during the collaborative process by deciding on the criteria and evaluation methodology to be used in the RFP beforehand and by employing an independent, third-party monitor. For a more detailed description of an RFP for unit-contingent power, see Appendix A.

However, RFPs also can be used to solicit standardized products (in addition to unit-contingent power) and can do so in a very transparent manner. For example, Maryland's four investor-owned electric utilities (Allegheny Power, Baltimore Gas and Electric Co., Delmarva Power & Light Co., and Potomac Electric Power Co.) issued a price-only RFP to meet their standard offer service (SOS) obligations. The RFP requested proposals from suppliers to provide shares of full requirements wholesale supply service as defined by the PJM RTO.[11]

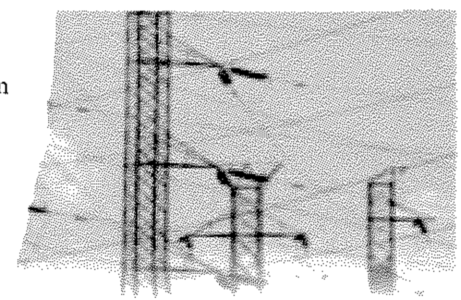
The RFP process and the model contract to be used was the result of a lengthy settlement effort involving the Maryland Public Service Commission (MPSC), the utilities and market participants. Key aspects of the RFP process and the RFP itself include: (a) the use of a technical consultant by the MPSC, who in conjunction with the MPSC Staff, monitors the entire RFP process from the flow of information to the actual evaluation procedures; (b) resolution of all non-price factors and contract terms prior to the solici-

[11] Full requirements wholesale supply service consists of capacity, energy, ancillary services and transmission losses.

tation via a collaborative effort; and, (c) the transparent evaluation of all bids based on a single discounted average price.

At the conclusion of the process, the technical consultant prepares a final report for the MPSC, which details the process and assures the MPSC that customers received the best possible deal.

B Price-Only Auctions



In price-only auctions, the winners are chosen solely on the basis of price (i.e., all non-price factors are settled beforehand). Another distinctive feature is that an auction employs multiple rounds of price bids. While there are various types of price-only auctions, the descending clock auction has gained credibility because it was the method used to procure roughly 18,000 MW of default service for customers in New Jersey. In a descending clock auction, an auctioneer announces prices in descending order until a price is reached at which the supply power offered is just sufficient to meet load.[12]

It is important to note that there can be price-only RFPs, too. For example, the 2004 Maryland Standard Offer Service RFP settled all non-price terms such as product types and credit standards. Suppliers will submit price-only offers for the provision of a share of full requirements service for specific customer types and contract lengths.

The primary difference between a price-only *auction* and a price-only *RFP* is the way prices are set. In the descending clock auction, the auctioneer

[12] An example of a different type of auction is the New York Independent System Operator (NYISO) new Installed Capacity (ICAP) auction system, also known as the ICAP demand curve. The auction determines the amount and price of ICAP each load-serving entity (LSE) must obtain for the following month. The NYISO auction system uses a downward sloping demand curve, which reflects the decreasing value of additional supply of capacity. The demand curve is administratively determined by the NYISO and is based on the cost of new entry and the decreasing value of installed capacity above the various locational ICAP requirements within the NYISO. For example, the demand price is set equal to the annualized cost of a new peaking unit at a capacity of 118 percent of peak load in each of the three areas: Long Island, New York City and the rest of New York State.

runs through multiple rounds of price bidding, but in the end, all winning bids are paid a uniform price. In the price-only RFP described in the previous section, bidders submit a price offer and winners are paid the price of each bid (i.e., non-uniform prices are paid).

Some benefits of price-only auctions and RFPs include: (a) the transparency of a price-only bid because all the non-price terms have been predetermined; (b) the limitation on the utilities' exposure to market risk by awarding the supplier a percentage share of the utilities' load rather than a fixed megawatt supply; and, (c) the limitation on the suppliers' exposure to keeping bids open—the turnaround time can be as short as a few days before commission approval. Possible downsides to auctions include: (a) a generally short-term length of purchase (i.e., one to two years for the awarded contracts) and (b) that price-only bids mean that there is no opportunity for suppliers to offer a lower price with less strict non-price requirements.

More information on the aforementioned descending clock auction for Basic Generation Service in New Jersey can be found in Appendix B.

BID EVALUATION PROCESS

IV. FAIR AND ACCURATE *Bid Evaluations*

This section examines six key issues involved in fairly and accurately evaluating bids: (1) the principle of comparability for all bidders; (2) transmission assessments of bidders; (3) cost-plus offers versus pay-for-performance bids; (4) comparing bids with unequal lives; (5) creditworthiness concerns; and, (6) balance sheet penalties. The important point in this section is that these issues should be openly settled during the collaborative process before the start of the solicitation. Generally, these issues become more contentious when evaluating bids in non-RTO areas. For instance, issues such as transmission assessments are contentious in non-RTO areas because there are no independent transmission authorities to make an objective assessment of the need for and cost of transmission upgrades.

A Comparability

The golden rule of comparability (treat others as you treat yourself) means that all bidders should meet the same requirements and be evaluated under the same standards so that no single bidder has an unfair advantage over another bidder. Two quick examples demonstrate this point. The first example involves a Firm Liquidated Damages (Firm LD) product, which requires the supplier to either provide power at the agreed-to price or pay any higher costs for replacement power. If a utility affiliate offers a Firm LD energy product in which the affiliate's bid is backed up by the utility's own generation reserves, then that utility should offer the same reserve service to all the non-affiliated competitors under the same price and non-price terms. To do otherwise would confer upon the affiliate an unfair advantage in the solicitation.

The golden rule of comparability means that all bidders should meet the same requirements and be evaluated under the same standards so that no single bidder has an unfair advantage over another bidder.

The second example in which comparability is particularly pertinent is when a utility's self-build option is on a cost-plus basis. Cost-plus means the offer is not a fixed-price bid and the utility or its affiliate is able to come before the commission in the future to pass through costs such as unanticipated capital expenditures or major maintenance costs. In this instance, the utility or its affiliate can offer a lower price bid, knowing that it can come back before the commission to request recovery for unanticipated costs. This would confer an unfair advantage to the utility or its affiliate as compared to a fixed or fixed formula offer from a competitive power supplier, which must bid higher to account for added risk. The evaluation, as will be explained later, must take into account this difference in consumer risk.

B Transmission Assessments

Assuring the reliability of a bidder's supply is a legitimate and important goal for a competitive solicitation in terms of both generation (physically being available) and transmission (physically being able to deliver). However, one key concern during bid evaluations is how to fairly and accurately assess the deliverability of a bidder's power. For example, a bidder rightly may be required to be a network resource to be eligible to bid. If so, the solicitation process should include an opportunity for any bidder to receive a timely and fair estimate of whatever system upgrades or other transmission-related costs that the bidder would incur to serve as a network resource.

Oftentimes, in the absence of RTOs, there are complaints of biased transmission assessments that inflate the amount of transmission-related costs necessary to ensure that electricity from a specific resource is deliverable. Further, there is the central question of who pays for upgrades. Outside well-functioning RTOs, there are sometimes allegations that the upgrades in question are in fact network upgrades and should be rolled in to rates not borne by bidders. Obviously, these issues are much easier to address in a well-functioning RTO area. In all instances, however, the most important principle is that all bidders should be *treated* comparably.

A different but related complaint is that, if transmission constraints are found for the moment with respect to certain bids, those bids might be rejected for the entire term of the proposal, which could be up to 25 years.

As already noted, deliverability of power should be an important factor in evaluating bids, but there are ways to evaluate this factor without rejecting bids for the entire term. From the customers' perspective, if the cost of upgrades to relieve the constraint is included in the price of a bid and the bid is still the lowest price bid, then a contract should be signed with that supplier on the date deliverability is available; interim service can be procured from other suppliers, including the utility affiliate.

C Cost-Plus Offers

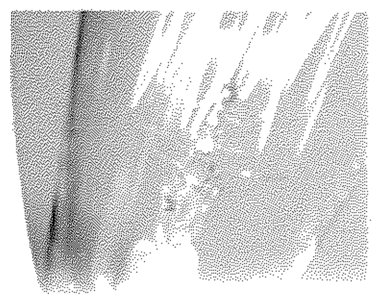
The concern here is how to properly evaluate the higher risk that cost-plus offers impose on customers as compared to fixed-price offers. In a cost-plus offer, the bidder does not guarantee the customer benefits asserted in that bid. In contrast, bidders offering a pay-for-performance PPA are willing to guarantee the customer benefits asserted in their proposals.

This concept of cost-plus versus fixed-price offers can be best demonstrated through the analogy of a customer taking bids to get his or her house built. One builder comes to the customers and says, "I think I can build the house you want for about $250,000, and I think I can build it with the features you want. However, I will not sign a contract that guarantees the price nor what features the house will have, but you will pay all costs I incur, pay me a profit on top of that, and accept the house as built." This is the cost-plus builder. Another builder says, "I will build the house you want for $250,000, and I will guarantee that price as well as the features of the house by signing a contract. If it is not what you wanted, you do not have to take it." This is the pay-for-performance builder. It would seem implausible that a customer would ever choose the cost-plus offer over a readily available pay-for-performance contract. The added risk of cost-plus is too much to bear.

If a solicitation in the electricity business does allow cost-plus offers to be submitted during a solicitation, the added risk to customers must be addressed. One approach is to limit the payments the cost-plus seller receives to the estimates provided by the seller in its offer during the solicitation. For example, if the seller offers the utility a cost-plus formula, but estimates (for comparison of bids) that the capacity payment will be roughly $95/kW-yr (again not guaranteed), then the commission should limit all payments to the supplier to $95/kW-yr over the full term of the contract. This would help protect customers by forcing cost-plus offers to have a more realistic appraisal of the costs that will actually be incurred.

Another approach is to apply a risk premium to the cost-plus offer in the evaluation of bids. The risk premium could be based on historical experience on cost pass-throughs with similar technologies. For example, if cost pass-throughs raised rate base by 20 percent in the past, the capacity related price in the cost-plus bid would be raised by 20 percent for purposes of bid evaluation.

D Unequal Lives



How should a utility choose between a lower priced offer to supply power for 10 years (say at $40/MWh) and a higher priced offer for 20 years (say at $50/MWh)? Clearly, for the first 10 years, the $40/MWh offer wins easily. The issue is how the two offers compare in the second 10 years. What should be assumed about what replaces the 10-year offer?

One approach that allows for more transparency is the use of the annuity[13] method, and while it need not be the only method used, it should be among the methods used when comparing offers of unequal lives. Indeed, financial theory dictates the use of the annuity method to compare options that have unequal lives. That is, the two proposals should be compared on the basis of their annuities. The annuity of the 10-year offer would be calculated over 10 years and that of the 20-year offer would be calculated over 20 years. The proposal with the lower annuity is the better choice.[14]

[13] An annuity is an equal annual payment over the life of the investment that has the same present value as the actual, unequal annual costs of the investment.
[14] This method is recommended by financial textbooks for evaluating investments or purchases of unequal lives because it is incorrect to directly compare the net present value of projects that have unequal lives.

Again, it is important to note that with any approach, assumptions must be made about what happens when the shorter-term proposal expires. With the annuity approach it is presumed that the initial offer is repeatable. This means that the gap between the 10- and 20-year options would be filled by assuming that the 10-year option would be repeated over time. An alternative is to allow the utility to assert the price and terms of the power supply in the years between the two offers. For example, a utility may "fill in" the second 10 years of the shorter-term offer with the assumed cost to build a new power plant a decade later. The primary appeal of the annuity method (as compared to the fill-in method) is that it lets the bid speak for itself. This greatly enhances the credibility of the solicitation process because it does not allow any bias to occur by letting the utility (a competitor) speak for that bidder.

In addition, making assumptions about the costs that a bidder would be willing to offer in the remaining years is challenging, given the many opportunities for technological advancement (e.g., a hydrogen-based fuel economy and decentralized generation). In other words, a utility may have an opportunity to purchase power in years 11 through 20 from a different supplier that may use more advanced, cheaper and environmentally friendly technology. Technological change makes the fill-in method fraught with uncertainty.

E Creditworthiness Concerns

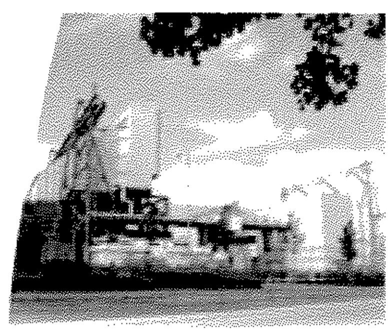
State commissions are rightfully concerned about how power suppliers will contractually fulfill their obligations to utility customers. This concern manifests itself during competitive solicitations in the types of creditworthiness requirements imposed on bidders. Ideally, market participants would address ways to mitigate these concerns during the collaborative process. The goal is to openly discuss and agree upon these issues so that all parties know and understand their obligations.

> State commissions are rightfully concerned about how power suppliers will contractually fulfill their obligations to utility customers.

Both the nature of the risk being addressed and the full range of ways to mitigate that risk should be discussed. For example, consider the risk that a specific power plant will be available to run when a supplier is in financial distress. To address this risk, participants in the collaboration could discuss a model PPA that could include certain terms and conditions to protect customers such as measures that could "physically" give customers comfort by knowing that they can have access to the power plant in the event of trouble or default.

Additional requirements for both asset-backed and financial (non-asset backed) offers that can provide additional comfort include provisions for the supplier to pay for the replacement cost of power. At the outset, it must be confirmed that all bidders — utility and non-utility alike — face this requirement. This is important, since traditional cost-plus rates do not include the requirement to pay for replacement costs. A requirement to pay for replacement will require an assessment of the bidder's financial status and may trigger collateral requirements. Again, comparable standards must be applied to all bidders. The amount of collateral required may be tied to (a) the buyer's replacement cost exposure and (b) the suppliers' financial status in terms of bond rating and net worth. Collateral requirements can be typically met by either (1) cash, (2) a parent guarantee, and/or (3) a letter of credit. These requirements, individually or as a combination, can be used to mitigate risks to the customers.

F Balance Sheet Penalty



A few state commissions have allowed their utilities to reflect in the bid evaluation process a possible adverse effect on the utilities' balance sheets from signing a PPA with a third party. The motivation for this comes from financial ratings agencies such as Standard & Poor's (S&P), who assert that the capacity payments in a PPA are to some extent, in some circumstances, the equivalent of debt. The argument for reflecting this in bid evaluations is that, with this added "debt equivalent," the utility will have to add more equity to its balance sheet. Since equity costs more than debt, there is a cost to signing the PPA and that cost should be used as a penalty against non-utility bids.

Two questions then arise during the competitive solicitation process. First, should the utility assess a "balance sheet penalty" to the third-party suppliers when evaluating proposals? Second, if it is assessed, how should it be calculated? The second question is answered in detail in Appendix C, "Hypothetical Example of the Calculation of the Balance Sheet Penalty." If a penalty is imposed, it should be calculated fairly and accurately because it could potentially add millions of dollars to the total cost of non-affiliate proposals and bias the results of the competitive solicitation in favor of the utility.

As to whether the balance sheet penalty should be assessed, each market participant may have its own viewpoint. However, the state commission should take the viewpoint of the utility's customers. Taking their viewpoint is important because they, and not the utility stockholders and debt investors, are the ones that will be paying for the power and for any penalties applied.

From the customers' perspective, if the penalty is imposed, they would ask the commission 'why, if the utility or the affiliate loses in the competition to supply power because its power is higher cost and/or higher risk, should the commission reward the utility by increasing the amount of equity return it receives?' Stated more bluntly, as a reward for not offering the best deal to customers, the utility is asking the commission to approve an increase in rates so that its equity investors can earn more return on equity.

Also, from the customer viewpoint, the commission should ask what level of debt obligation customers would prefer. If the utility had two options, either (a) build a plant that requires $150 million in debt investment or (b) enter into a PPA with a non-affiliated supplier with capacity payments that have a present value of $150 million, which would the customer choose? To put a fine point on this, just think of the consequences of the worst case — the power plant simply fails to work after it is brought into commercial operation. With the pay-for-performance PPA, the customer owes nothing, because if there is no performance, there is no payment. In sharp contrast, with the utility's self-build or lease option, directly or indirectly, the customer is on the hook for $150 million. Again, the customer clearly would choose the pay-for-performance option.

State commissions must see that S&P looks at this with the exclusive perspective of that of the debt investor, not the customer perspective. S&P's intent is to alert the debt investor to the possible off-balance sheet obligations of a company that could compete for payment with loan repayment at times of financial distress for the utility. Rather than just passively going along, utilities can work with S&P to understand the terms and conditions of the PPA and that if determined to be prudent, the PPA payments will be made and do not compete with debt repayment. This may sway S&P to determine that no debt equivalent should be calculated.

CONCLUSION

V. CONCLUSION

Regardless of the solicitation format used, the product types solicited, or the approach to evaluation chosen, all decisions for the solicitation should be guided by one goal: to obtain the best possible deal for customers by *credibly* evaluating the full range of resource alternatives offered in the wholesale power market. If designed properly, competitive solicitations can be used to determine the prudence of resource procurement decisions and demonstrate the lack of affiliate abuse. However, in order for the results to be credible, the competitive solicitation should be fair and transparent. Such credibility can be achieved via the use of a collaborative process and/or an independent, third-party monitor. Ideally, the collaborative process settles as many issues as possible before the solicitation proceeds so that all involved have a clear understanding of what the solicitation entails. In the end, customers, utilities and state commissions want to buy power that is reliable and affordable, and competitive power suppliers want to sell their power. Properly designed competitive solicitations can result in an outcome in which consumers are assured of receiving the least-cost power available from the best mix of resources.

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APPENDIX A

EXAMPLE *of an RFP for Unit Contingent Power*

(MEANT TO ILLUSTRATE THE ISSUES FACED; IT IS NOT OFFERED AS A TEMPLATE FOR RFP DESIGN)

The purpose of this exhibit is to give an example of the methods that could be used to develop an open and fair competitive solicitation through the use of a request for proposals (RFPs) for unit-contingent power. This exhibit is based on a document distributed for an actual collaborative process in which it served to guide the discussion for this type of solicitation and product. It is believed to list the measures needed to obtain the best deal for customers in terms of price, risk, reliability and environmental performance. All the specific features would be tailored to the actual customer needs in a specific area of the country.

PRODUCTS

If the RFP solicits unit-contingent asset-backed offers, then the product should include capacity and energy. Potential bidders would include unit sales and system sales.

- **Asset-backed unit-contingent offers allow customers to receive the benefits of dispatchable generation similar to the utilities' own generation.**
- System sales include bids that identify a system or portfolio of assets.
- This does not require that a bidder have ownership of the asset(s); instead it requires that a bidder show proof that it has control of the asset(s), and that the asset(s) is deliverable.

RESOURCES

All types of resources (i.e., generation, distributed generation, demand-side management, renewables, portfolio bids, etc.) are allowed to submit bids provided that their bid identifies an asset(s).

- Bidders must demonstrate that they are able to provide the product that is being solicited (i.e., demand-side bids will be accepted if they can demonstrate that they are effective alternatives to peaking capacity).

- For portfolio bids, if a seller offered a bid that identified a portfolio of assets, the seller must prove that each asset is deliverable to the utility. Then, when the energy is required to be scheduled by the utility (this is likely to occur 24 hours in advance of delivery, but the utility would have some discretion in this regard), the bidder would identify the precise asset(s) that will be used.

CODES OF CONDUCT / AFFILIATE RULES

- If an affiliate of the utility bids, then it will be evaluated under the same rules as any other bidder and must be held to its bid if it wins.
- The commission should impose a "zero tolerance" standard. That is, if any significant misconduct occurs before or during the solicitation by the utility or the affiliate that results in an unfair advantage toward an affiliate, then all affiliates should be banned from the solicitation.

LENGTH OF CONTRACTS

The RFP should solicit a range of contract terms to develop a diversified portfolio and protect customers.

- The utility will file with the commission its portfolio-term preferences for approval (e.g. the utility prefers 60 percent of the RFP capacity procured under 10-year terms, 20 percent under 5-year terms, 10 percent under 3-year terms, and 10 percent under a 1-year term). This preference will be made public as part of the collaborative RFP process.
- The commission should promote customer risk protection by establishing an incentive system for load serving entities to better manage price and volatility risk.

STRUCTURE OF PRICE BID

All bids submitted in the RFP shall include the following features to ensure that (a) the customers will receive reliable products and services and (b) the suppliers are accurately compensated for those products and services.

1. Capacity Price: This will ensure that the resource is available to supply capacity and energy.
   - Stated in $/kW-year for each year of the contract term; or, initial-year stated and then indexed to inflation.
   - The capacity price must be tied to an availability guarantee.
2. Availability Guarantee: This will ensure that the customers are protected against poor performance.
   - The capacity price would be paid in full if, and only if, the facility was available for service 95 percent of the time, on average, over the previous 12 months. If it was available for less than 95 percent of the time, capacity payments would be reduced proportionally, and the seller would be responsible for the replacement cost of power. If the performance fell below 50 percent availability, no capacity payment would be made.
   - If availability was above 95 percent, then the supplier would receive a proportional bonus for each percentage point above 95 percent.
   - A guaranteed megawatt output will be stated.
3. Energy Price: Compensates the supplier for providing energy to the customers.
   - The energy price will either be a fixed price ($/MWh) stated for each year; or,
   - Stated as a guaranteed heat rate and a fuel price tied to some publicly available fuel price index.
   - Gas tolling offers are acceptable and, in this case, a guaranteed heat rate must be offered.
   - For portfolio bids or system sales, the bidder would have a single fixed energy price or heat rate for all the assets.
4. Fixed Operation & Maintenance (FO&M) Cost
   - An explicit fixed cost in terms of $/kW-year for each year of the contract length, or an initial-year price indexed to inflation.
   - FO&M also will be tied to the availability guarantee.

5. Variable Operation & Maintenance (VO&M) Cost

   - VO&M will be a fixed price in terms of \$/MWh stated for each year or an initial-year price indexed to inflation.

   - Start Price: The cost in \$/start can be fixed or tied to a publicly available index.

MODEL PPA

The RFP should include a model PPA to be used as a template for bids. This PPA will detail all the required and/or preferred price and non-price terms. The goal is to streamline the bid evaluation process by settling most contract issues upfront. The following items are some specific features that should be included in the model PPA to ensure that bids can be compared equally.

1. Dispatchability: Each generation asset is dispatchable based on its energy price plus VO&M plus transmission losses. Each bid must submit the necessary parameters for dispatch such as:

   - Minimum load level,

   - Ramp rates,

   - Minimum run times, and,

   - Start-up times.

2. No Regulatory-Out Clause

   - The RFP itself will be the prudence review, and, therefore there is no need for an ongoing prudence review of the contract. Since there is no risk of a disallowance, there is no need for a regulatory-out clause.

3. *Force Majeure* will be defined using the industry standards for events out of the control of the parties.

4. Security Deposit

   - Construction Period Security Deposit shall be in the form of a letter of credit (or an acceptable substitute) for \$30,000/MW and be applicable from the date that the winning bidder(s) signs the PPAs until the in-service date of the asset.

   - Operation Period Security Deposit shall be in the form of a letter of credit (or an acceptable substitute) for $30,000/MW and be applicable for the entire term of the contract.

- Additional security in the form of a second lien (secondary mortgage) on the asset(s) also could be imposed as recourse when a default occurs.

5. Construction Milestones
   - If a bidder's asset is not on-line, it must contractually guarantee to meet milestones, such as the completion of permitting, financial close and equipment delivery.
6. Liquidated Damages
   - A bidder is liable for the replacement cost of power in the event of (a) early contract termination, (b) under-performance, or (c) failure to meet in-service date.
   - The Construction or Operation Period Security Deposits are the source of payment and set the limit for replacement costs.
7. Creditworthiness: Prospective bidders may submit bids only if they meet one of the following creditworthiness standards:
   - Bond rating of the company is investment grade;
   - The asset to be bid has been financed;
   - The asset has an investment grade guarantor; or,
   - Both Construction and Operation Period Security Deposits are increased to $100,000/MW.

BID EVALUATION IN THE RFP

If an affiliate of the utility participates in the solicitation, an independent monitor could be selected and hired by the commission to work alongside the commission staff to ensure fair treatment for all bids. The independent monitor should be deeply involved in the details of the evaluation process (i.e., ensuring that the details do not favor one participant over another).

The bid evaluation will be in two stages. The first will consist solely of an assessment of generation costs, and the second will take into account possible transmission system upgrade costs.

Stage One: *Generation Cost Assessment*

1. The initial generation cost bid evaluation will be done across a range of uniform capacity factors. The monitor, selected by the Commission, will specify the uniform capacity factors to be used (e.g., 10 percent, 20 percent, and so on) and each bid will yield a price at each capacity factor (a screening curve).

2. In addition to specifying the uniform capacity factors, the independent monitor will specify all other assumptions for evaluation such as natural gas prices or other fuel costs, and inflation.

3. With the uniform capacity factor evaluation, the costs will be represented as an annuity cost per MWh. The steps are as follows:

   - The annual costs for each price component (capacity, energy, VO&M, FO&M and starts) will be projected over the proposed term of the offer, at each of the uniform capacity factors.

   - The present value of these projected costs will be determined using the utility's after-tax weighted cost of capital as the discount rate.

   - To compare the contracts with unequal lives (i.e. a three-year contract as compared to a five-year contract) the bid evaluation should follow the annuity method. To be clear, if a 3-year offer is made, a 3-year annuity would be calculated. If a 5-year offer is made, a 5-year annuity would be calculated.

   - To adjust for unequal bid sizes, the annuities would be divided by the MWh of the bid, as dictated by each uniform capacity factor.

   - The monitor will rank the annuities per MWh and choose the lowest-cost bids sufficient to meet the megawatt level solicited.

4. If the monitor is satisfied with the uniform capacity factor evaluation, it need not go further in the generation cost evaluation. If, however, the monitor wants an additional analysis, it is entirely appropriate to add a production simulation based-bid evaluation.

   - Capacity factors for each bid would be determined through production simulation.

- Bid comparison would be done on the basis of the cumulative present value of the revenue requirement adjusted for differences in contract term and project size.

Stage Two: *Transmission System Upgrades Cost Assessment*

1. The winning bidders, based on generation costs, as a group, will be called the Minimum Supply Cost Portfolio (MSCP).
2. Transmission modeling will be used to determine the system upgrade costs, if any, associated with the MSCP. System upgrades will be made to assure reliability criteria are met.
3. The determination of system upgrade costs must be performed in a comparable manner for all bidders.
4. The cost of the MSCP is now reassessed taking into consideration transmission system upgrade costs. If the MSCP is judged to still be the lowest cost to customers, then the MSCP is the winning portfolio.
5. If the MSCP is clearly not the lowest cost portfolio, another portfolio of generation bids will be created. This will be called the Second-Best Supply Cost Portfolio (SBSCP). The SBSCP will include higher-cost generation bids that are expected to require lower transmission system upgrades. Transmission modeling will be used to determine the system upgrade costs of the SBSCP.
6. The costs of the MSCP and SBSCP now would be compared with the transmission costs included. The annuity cost of transmission upgrades would be added to the annuity cost of the generation bids. The lower cost portfolio would win.

LOAD-POCKET LOCATION

A separate analysis for load-pocket location for generation is required to determine if, and only if, system reliability requires load-pocket location for physical needs regardless of transmission capability.

- If a load pocket is a result of insufficient transmission capability, it is an economic decision captured in the transmission cost analysis detailed above. That is, if the cost of (a) generation outside the load pocket plus the cost of required system upgrades is more expensive than (b) the cost of in-pocket generation, then in-pocket generation will win the RFP without any locational preference. There is no need for a location preference if the reason for the load pocket is insufficient transmission capability.

- The utility may allow bidders to co-locate facilities with the utility, as possible, on its existing load pocket sites.
- If the utility mothballs or retires in-pocket units, it will include in the RFP a price at which out-of-pocket bidders may call on these units when transmission constraints are binding.

OTHER ISSUES

- Although many non-price factors are made comparable by the Model PPA, the value of non-price factors in bid evaluation must be made clear in the RFP evaluation process beforehand. For example, some value can be assigned to having completed construction or being in an advanced stage of construction.
- Confidentiality: All bids are confidential. The PPAs from winning bids may be made public upon contract signature.
- Dispute Resolution: Each bidder may be entitled to a post-bid meeting with the Bid Evaluation Team if it is omitted from the short-list, or it is not a winner after being on the short-list. If a grievance remains, losing bidders (a) will agree to arbitration on matters concerning the evaluation of its bid or (b) can appeal to the commission for serious breaches of procedure only. The entire RFP must be re-opened if procedural breaches are found to benefit the utility or its affiliate.
- Bid Fee: A non-refundable $8,000 fee per bidder (covering up to three bid alternatives) will be assessed to defray the cost of the independent monitor.

APPENDIX B

EXAMPLE *of a Price-Only Auction*

(NEW JERSEY BASIC GENERATION SERVICES AUCTION)

The purpose of this exhibit is to give the commission an example of the methods to be used in developing an open and fair competitive solicitation through the use of an auction format. The example described is from New Jersey's Basic Generation Service (BGS) Auction.

NEW JERSEY'S BASIC GENERATION SERVICE AUCTION

In February 2003, New Jersey's Electric Distribution Companies (EDC) successfully utilized a declining block auction to supply BGS.[1] It should be noted that this auction was performed under the structure of the PJM Interconnection and thus under an open and level playing field for participants. With that in mind, this description of the New Jersey Auction is included to aid in the understanding of this form of competitive solicitation.

The state's four incumbent EDCs: Public Service Electric and Gas Co. (PSE&G), Jersey Central Power & Light Co. (JCP&L), ACECI/Conectiv Power Delivery (Conectiv), and Rockland Electric Co. (RECO) held a descending clock auction to bid out their BGS load. Roughly 18,100 MW was solicited for two products. The first product, Fixed Price (FP) service, for small to mid-size customers, pays suppliers a fixed price (in cents-kWh) to cover their costs (suppliers must use this price to cover capacity, energy, ancillary service and transmission costs). The peak capacity solicited for this product totaled approximately 15,500 MW. The second product, Hourly Electric Price (HEP) service, for large customers, pays suppliers a capacity payment ($/MW-day) which is determined in the auction and an energy payment determined by the PJM zonal real-time hourly market. In addition, suppliers are paid the pre-specified ancillary service rate and transmission rates according to PJM's Open Access Transmission Tariff (OATT). The capacity solicited for this product totaled approximately 2,600 MW.

[1] More information is available at http://www.bgs-auction.com.

DESCENDING CLOCK AUCTION DETAILS

According to the auction rules, each EDC's peak BGS load is divided into roughly (a) 100 MW tranches for the FP product and (b) 25 MW tranches for HEP product.[2] An auctioneer runs the solicitation by stating the initial price of each EDC's tranche, then the suppliers bid for the number of tranches they would like to serve. If the total number of tranches bid by the suppliers is greater then the number of tranches desired by the EDC, the auctioneer would hold another round of auctions and "tick down" or lower the price. This continues until the number of tranches offered by suppliers equals the number of tranches desired by the EDC.

The winning bidders are awarded a fixed percentage of the EDC's load based on the number of tranches won. For example JCP&L wanted to offer 30 tranches (roughly 30–100 MW blocks) for their 10-month FP product. If a bidder won five tranches it would provide full service requirements for one sixth (5/30 tranches) of JCP&L's BGS load in all hours. In short, suppliers are not guaranteed a fixed number of megawatts, but rather a right to serve a fixed percentage load.

A winning supplier provides full-requirements service. That is, the provider is responsible for fulfilling all the requirements of a PJM Load Serving Entity (LSE) including capacity, energy, ancillary services and transmission, and any other service as may be required by PJM. A supplier may win one or more tranches for one or more EDCs and for one or more terms.

TERM LENGTH

The length on contract terms in the auction is short term. The FP auction awarded two-thirds of the tranches to 10-month contracts and one-third to 34-month contracts. The HEP auction awarded contracts for 10 months of service.

[2] Each tranche (or block of power) is actually slightly less than 100 MW for FP to make the number of tranches a whole number. E.g. JCP&L's peak load is 2,973 MW, but in order to have 30 equal size tranches the megawatts must be reduced to 99.1 MW per tranche. (99.1 MW x 30 tranches = 2,973 MW)

CONTRACT

Once the auction is closed, the prices are final. There are no negotiations and suppliers are required to sign a predetermined contract. While the auction price is final, the price actually realized by suppliers varies by season. Built into the auction are seasonal factors (greater than one for summer, less than one for winter) that are multiplied by the auction price to take into account seasonal variability. The factors vary by EDC for the summer from 1.11 to 1.24 and for the winter from .92 to .96. For example, PSE&G's 10-month FP closing auction price was 5.386 cents/kWh. Its summer factor is 1.1423, therefore the price charged during the summer months is 6.152 cents/kWh.

RESTRICTIONS

- Each bidder must post a letter of credit or bid bond of $500,000 per tranche for the FP service (translates into roughly $5/kW) and $125,000 per tranche for the HEP product for the number of tranches offered in the first round of bids. Depending upon creditworthiness, an additional security deposit could be required.
- Each EDC submits a load cap on the number of tranches any one bidder is allowed to serve. The goal is to prevent any one bidder from influencing the auction and overexposing the EDC to a single supplier.
- There are minimum and maximum statewide starting prices. The EDCs agreed upon two prices to give the auctioneer a range of values to begin the solicitation.

APPENDIX C

HYPOTHETICAL *Example of the Balance Sheet Penalty*

While we do not recommend the use of the balance sheet penalty in the evaluation of bids, if it is used in some context, there are several steps involved in calculating the balance sheet penalty. First, the utility calculates the present value of the capacity payments as defined in the PPA using the utility's after-tax weighted average cost of capital as the discount rate.[3] Next, the utility assesses the risk level associated with the PPA and multiplies the risk percentage times the present value to get the imputed debt. The next calculation is the required equity needed to keep the debt-to-equity ratio consistent with the utility's original balance sheet, prior to the execution of the PPA. The utility then imputes a pre-tax interest payment (based on the utility's equity return) necessary to support the imputed debt.

To illustrate, Table One presents a hypothetical example of the calculations. First, the present value of the capacity payments for our hypothetical PPA is $150 million.

Second, the utility asserts that 12 percent of that present value of capacity payments is the equivalent of debt. This leads the utility to add $18 million of what is imaginary debt to its balance sheet to reflect this debt equivalent; with the addition of imaginary debt, we will refer to this as the utility's hypothetical balance sheet.

Third, because the addition of this imaginary debt means that the utility will have a higher debt-to-equity ratio, the utility asserts that it will have to add equity to restore the debt-to-equity ratio it would have had prior to signing the contract. The utility declares that it wants debt to be 40 percent of its total capitalization. If the utility wants to regain its 40 percent debt share, it must add $27 million of equity to its balance sheet. Thus, it will add a total of $45 million to its hypothetical balance sheet with $18 million (40 percent) coming from imaginary debt and $27 million (60 percent) coming from equity.

[3] The assumed discount rate is 11 percent and it is not forced to be equal to the cost of capital for the hypothetical equity-debt swap.

Fourth, if $27 million in equity must be added, then the utility claims that customers must pay the pre-tax return on equity for that added equity investment. The utility asserts that the pre-tax return is about 18.5 percent (an after-tax rate of 12 percent grossed up for income taxes of 35 percent). In the first year, the added return on equity would be $4.98 million ($27 million multiplied by .185). The utility calculates this added return on equity for each year of the PPA; the dollar amount of return declines each year because the amount of equity is shown to decline each year due to depreciation.

Fifth, before the penalty is applied, the utility deducts from the penalty the cost of debt, since in reality the utility is asking to simply swap equity for debt. (Actual total capitalization does not change, since the PPA causes only imaginary debt.) Thus, the net cost is the equity return less the debt return that would have been paid.

Sixth, the utility calculates the present value of these added annual returns on equity after deducting the cost of debt. This present value of annual equity returns after deducting the cost of debt is the balance sheet equalization penalty that the utility assesses against the competitive power suppliers. Assuming a 20-year straight-line depreciation, our example would lead to a $20.4 million penalty. That is, the utility would treat the $20.4 million penalty as if it were a cost of signing the PPA, thus giving the utility's own power plants an artificial cost advantage. In this example, that advantage amounts to artificially increasing the competitor's capacity cost by 13.6 percent on a present value basis ($20.3 million divided by $150 million).

TABLE ONE: *Balance Sheet Equalization Penalty Example*

NPV of Total Capacity Payments:	$150,000,000
Risk Factor:	12%
Imputed Debt:	$18,000,000
Required Equity (60% Equity Target):	$27,000,000
Amortization Factor:	$1,350,000
Discount Rate:	11.00%
Depreciation Life:	20
Pre-Tax Return on Equity:	18.46%

Y_n	Equity Amount (a)	Return at 18.46% (b)	Debt Payment at 6% (c)	(b) - (c)
1	$27,000,000	$4,984,615	$1,620,000	$3,364,615
2	$25,650,000	$4,735,385	$1,539,000	$3,196,385
3	$24,300,000	$4,486,154	$1,458,000	$3,028,154
4	$22,950,000	$4,236,923	$1,377,000	$2,859,923
5	$21,600,000	$3,987,692	$1,296,000	$2,691,692
6	$20,250,000	$3,738,462	$1,215,000	$2,523,462
7	$18,900,000	$3,489,231	$1,134,000	$2,355,231
8	$17,550,000	$3,240,000	$1,053,000	$2,187,000
9	$16,200,000	$2,990,769	$972,000	$2,018,769
10	$14,850,000	$2,741,538	$891,000	$1,850,538
11	$13,500,000	$2,492,308	$810,000	$1,682,308
12	$12,150,000	$2,243,077	$729,000	$1,514,077
13	$10,800,000	$1,993,846	$648,000	$1,345,846
14	$9,450,000	$1,744,615	$567,000	$1,177,615
15	$8,100,000	$1,495,385	$486,000	$1,009,385
16	$6,750,000	$1,246,154	$405,000	$841,154
17	$5,400,000	$996,923	$324,000	$672,923
18	$4,050,000	$747,692	$243,000	$504,692
19	$2,700,000	$498,462	$162,000	$336,462
20	$1,350,000	$249,231	$81,000	$168,231
21	$0	$0	$0	$0
NPV	**$163,972,298**	**$30,271,809**	**$9,838,338**	**$20,433,471**

Electric Power Supply Association
1401 New York Avenue, NW, 11th Floor
Washington, D.C. 20005
Telephone: (202) 628-8200
Fax: (202) 628-8260
www.epsa.org

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Electric Power Supply Association
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