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Oregon Public Utility Commission
PO Box 2148
Salem, OR 97301-2148

Re: Docket No. UM 1182

Enclosed for filing are PacifiCorp's Opening Comments in this matter. A hard copy was served on all parties of record as indicated on the attached certificate of service.

Very truly yours,

Katherine A. McDowell

KAM:jlf
Enclosure
cc: Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1182

In the Matter of an Investigation Regarding Competitive Bidding	**PACIFICORP'S OPENING COMMENTS**

I. INTRODUCTION

PacifiCorp hereby submits these opening comments in accordance with the procedural schedule previously adopted in this proceeding.

A. Background

As set out in PacifiCorp's December 21, 2004 letter to the Commission, PacifiCorp supports the opening of a competitive bidding investigation, but opposes any significant changes to the Commission's Order 91-1383, which originally established the Commission's competitive bidding requirements for investor-owned electric utility companies. Order 91-1383 has enjoyed remarkable durability over the last 14 years, despite significant changes in electric energy law and policy since 1991. This is most likely due to the fact that Order 91-1383 struck the appropriate balance between making the bid evaluation process understandable and fair, and the need to make the process as flexible as possible to account for changing circumstances, advancing technologies and evolving energy markets. In Order 91-1383, the Commission explained that did not intend to usurp the role of the utility decision-makers, and stated it is preferable for the Commission to establish guidelines and for the utilities to make specific decisions within those guidelines.

PacifiCorp has been working closely with the Commission Staff ("Staff"), Portland General Electric ("PGE"), and NIPPC in developing a Straw Proposal that addresses each party's proposal for amendments to the competitive bidding process set out in Order 91-1383. Staff forwarded its final Straw Proposal to the parties on September 27, 2005, and

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requested that parties use Staff's Straw Proposal as a point of departure in parties' opening comments and to indicate where parties would delete, revise, or add specific language. Consistent with Staff's request, PacifiCorp's opening comments respond to Staff's Straw Proposal. In addition, PacifiCorp has prepared a redlined version of Staff's Straw Proposal incorporating PacifiCorp's comments, which is attached as Attachment A.

PacifiCorp greatly appreciates Staff's effort and thought in preparing its Straw Proposal. Largely because of Staff's cooperative efforts in this docket, PacifiCorp fundamentally agrees with Staff's framework for the competitive bidding process. Nevertheless, PacifiCorp has identified several areas in which PacifiCorp's Straw Proposal departs significantly from PacifiCorp's proposed approach, which are summarized in Section II.

Additionally, in Section III, PacifiCorp discusses the issues identified by the Commission in its June 6 ALJ Memorandum as issues of particular interest, but not addressed in Staff's Straw Proposal.

II. COMMENTS ON STAFF'S STRAW PROPOSAL

A. Guideline 1: RFP After IRP

In Guideline 1 of its Straw Proposal, Staff recommends language that PacifiCorp believes is an integrated resource planning ("IRP") issue, which is currently before the Commission in docket UM 1056. PacifiCorp submitted comments in that docket. As part of its comments, PacifiCorp explained that utilities should not be required to identify in their IRP Action Plans their acquisition strategy for each specific resource, including whether they intend to use competitive bidding and if so, if they intend to have a self-build or build, own, transfer options. Rather, PacifiCorp submitted that the procurement process, which may or may not consist of a Request For Proposals ("RFP"), is the appropriate place for that analysis, because it is the procurement process that will determine if a market exists for the resource that is modeled as the proxy resource in the IRP. Other parties have submitted

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comments proposing a different approach to this issue. PacifiCorp's draft language in Guideline 1 reflects PacifiCorp's position in UM 1056. Ultimately, PacifiCorp believes that the language in Staff Guideline 1 should track the Commission's resolution of this issue in UM 1056.

B. Guideline 2: RFP Requirement

Staff's Guidelines define a "Major Resource" as a resource with durations greater than 5 years and quantities greater than 50 MW. PacifiCorp opposes such a low threshold, and instead proposes that a Major Resource should be defined as a resource with durations greater than 10 years and quantities greater than 100 MW. There are several reasons why the low 5 year/50 MW threshold is inappropriate.

First, the low threshold establishes a bias towards short-term power purchase agreements. The definition for a Major Resource should allow for the market options to be compared to IRP proxy resource (currently a cost to build model) in order to establish the least cost option for customers A 50 MW and 5 year term is not conducive to evaluating market against cost. This low threshold therefore establishes a bias towards short term power purchase agreements and potentially no development of assets. This may not result in the best cost/risk balance to customers. It is our experience, in past RFPs, that the market will not always provide a Power Purchase Agreement proposal from a new asset unless it is a minimum of 100 MW and greater than 10 years. This is due to technology and financing constraints which would dictate longer-term and larger size bid proposals. In order for there to be a benchmark resource to evaluate market and cost, the minimum requirements should be established at a term and size that permits the viability of benchmark and asset-based options.

Second, a formal RFP process itself requires an extensive and comprehensive commitment from the utility, the Commission and the bidders to complete. As set forth in Staff's Guidelines, the RFP process could take up to several months before an RFP is issued,

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followed by RFP evaluation and negotiation time and, finally, an acknowledgment proceeding if pursued by the utility. All in all, this process could take up to 18 months to complete. A formal RFP mandate is not compatible with resource decisions involving such a low threshold such as 5 years and 50 MW and may result in frequent filings with large time commitments of the Commission and Staff. Indeed, PacifiCorp's most recent IRP calls for substantial Front Office transactions. Many of which may fall in the greater than 5-10 year range.

Finally, having to issue an RFP for every 50 MW with a five or more year term would impair PacifiCorp's ability to actively hedge their position in the liquid forward markets and may increase cost to customers. For example, PacifiCorp's experience in the energy markets has shown that there is an active market for power and natural gas in the shorter and mid-term that does not require or generally use an RFP process. . Thus, PacifiCorp can currently take advantage of these markets when they are economic and otherwise advantageous to the Company and its ratepayers. Further, in the west, this market currently trades in standard 25 MW increments; thus, a 50 MW threshold on a five-year or more term is putting a very low threshold to trigger a laborious RFP process. This type of market is far from amenable to an 18-month process before transactions can be consummated nor is the market amenable to the costs and time commitment on the bidder-side. In other words, a seller in that nearer-term market will likely not choose to participate in a lengthy RFP process when it could otherwise choose to sell its power at the then current market traded price and not have to compete through a lengthy RFP process that includes increased costs such as bid preparation fees or bid fees. If this Commission were to impose the RFP requirement on those types of deals, PacifiCorp believes that these types of deals will become largely unavailable to the company through this process.

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For these reasons, PacifiCorp proposes changes to Guideline 2 to define "Major Resource" as involving resources with a duration greater than 10 years and quantity greater than 100 MW.

C. Guideline 3: Exceptions to RFP Requirement

PacifiCorp proposes one important change to Staff's proposed language. The definition of exceptions to the RFP requirement expressly excludes the case involving "self-build" resources for solving an emergency situation or taking advantage of a time-limited resource opportunity. PacifiCorp submits that this definition artificially and inappropriately excludes options available to the Company for solving an emergency situation or for taking advantage of a time-limited opportunity which in both cases may result in lower costs to customers.

For example, if an emergency situation presented itself that required a short lead-time resource, the best option might be to enter into a power purchase agreement or purchase a distressed asset from an independent power producer, as we have seen in the industry recently. In both cases, short time frames can be present (as little as 2-3 weeks) where these opportunities are available to market. In addition, in a transmission constrained area for example, the best option might be for the utility to install a simple-cycle combustion turbine located temporarily on a Company site until such time as the emergency can be corrected (such as an expected extended generator outage). Likewise, a time-limited, joint-ownership opportunity on a new resource might present itself outside of an RFP process. It is not implausible to imagine a scenario where the opportunity to participate in such a project was limited by time constraints imposed by third parties. Finally, it is reasonable to assume that not all sellers are interested in being a bidder into a RFP process but may rather prefer to hold their own "reverse RFP" process wherein potential buyers bid into the sellers RFP. Indeed, such reverse RFPs are becoming more common in the market place. There is no compelling justification for limiting these type of options from the RFP requirement exceptions when

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they might provide better value for ratepayers. Instead, this proposal favors market options over ownership options without offering any compelling reason why in all or even most such cases the market options will be a better option for customers.

If parties are concerned that utilities may overuse this exception process to build its own resources, PacifiCorp would not object to these definitions of exceptions becoming part of the waiver requirement process. In other words, in order to take advantage of any time-limited opportunity or emergency, PacifiCorp would be required to file a request for a waiver from the RFP process with the Commission. In that way, the Commission and other parties would have an opportunity to ensure a prudent use of the waiver process. To respond to an emergency situation, the Commission could establish, or parties could request, expedited timelines faster than the 120 days contemplated by the Staff Guideline 4. PacifiCorp's suggested changes to Guideline 3 combine that section with Guideline 4 to implement this proposal.

D. Guideline 4: Waiver of RFP Requirement

Staff's Guideline suggests that the utility should request a waiver of a RFP requirement "in the utility's IRP." PacifiCorp's comments on this guideline are related to its comments on Guideline 1. For the reasons stated in PacifiCorp's opening and reply comments in UM 1056, PacifiCorp does not believe that the utility's IRP process is the appropriate forum for deciding whether or not the utility will conduct an RFP process for individual resource decisions. PacifiCorp submits that Staff's proposed language presupposes the outcome of that unresolved issue in UM 1056. As in Guideline 1, PacifiCorp's proposed changes to this Guideline 3 reflect PacifiCorp's position in UM 1056. Because that issue has not been resolved by the Commission, PacifiCorp suggests that this language, like that in Guideline 1, should ultimately track the Commission's resolution of the issue in UM 1056.

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E. Guideline 7: Independent Evaluator (IE)

Staff states in Guideline 7 of its Straw Proposal that the IE "should not be providing, or recently have provided, consulting services to participants in western energy markets." PacifiCorp disagrees with this requirement. While it is clearly important that the IE be an impartial and objective party in the competitive bidding process, it is also imperative that the IE be knowledgeable and experienced. Neither independence nor experience and competence should be sacrificed in the name of the other; each requirement is critically important to a successful competitive bidding process. Nor should independence be defined in such a manner that would prohibit relevant work in the energy business because such a definition would sacrifice the important experience requirement. PacifiCorp believes that the Commission's Guideline regarding the IE should generally state the Commission's policy to seek out IE's that satisfy both criteria. The Guideline should make clear that the IE must demonstrate independence and also sufficient experience to be able to competently undertake all of the tasks expected of the IE as outlined in the Guidelines.

The qualified pool of competent and independent IEs may be too small to categorically exclude IEs with recent experience in Western markets. Taken as written, Staff's proposal would disqualify any IE who is or recently performed an IE function in the west. Thus, creating an ever diminishing pool of candidates.

Instead, to accomplish the objective of ensuring an independent IE, instead of a including a definition that could preclude relevant experience in the Guidelines, the Commission should adopt a definition that permits experience but requires disclosure of actual and potential conflicts so that the Commission has then necessary information to assess independence. For example, the Commission could require conflict of interest declarations from potential IEs that disclose any actual or potential conflicts of interests that exist and that may arise during the course of the RFP. In addition, the IE would disclose any past (for example, two years) and current or anticipated relationship with any potential

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bidder, PacifiCorp, PacifiCorp affiliate or public utility commissions. The disclosure should specify the date, nature of scope of any such relationship. A similar disclosure statement would be a requirement for the IE Closing Report. To accomplish the objective of ensuring experience, the potential IE should provide a statement of prior experience related to competitive bidding processes, including statements regarding the specific type of process contemplated in the Guidelines. The IE should also demonstrate technical competence with respect to complex utility modeling programs and experience with standard power purchase and other acquisition type agreements.

PacifiCorp's suggested approaches to ensuring independence and experience need not be included in the brief high level Guidelines as proposed by Staff. Instead, the Commission should adopt an approach that permits it and its staff to evaluate the two key important IE characteristics: independence and experience without artificial restraint. PacifiCorp's suggested changes to Guideline 7 reflect this approach.

Finally, Staff's proposed Guideline states that the costs of the IE would be paid through assessments of "all bidders including the utility." PacifiCorp does not agree that the utility should be included in the bid fee process. The purpose of bid fees is to help defray the costs of the IE for ratepayers. Requiring the utility to also pay those costs does not further that objective. Second, the utility is not a "bidder" in the RFP process. Instead, the utility is the purchaser. Further when the utility includes a self-build benchmark option, the benchmark serves as a mechanism to protect ratepayers if the market response exceeds the costs by which the utility could build to meet the demand need. The utility should not be assessed the same fee as bidders under those circumstances. Finally, PacifiCorp submits that, given the mandated nature of the IE, that any IE costs not funded via bidder fees should be recoverable on a dollar for dollar basis in subsequent rate cases.

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F. Guideline 8(c): Bid Scoring and Evaluation Criteria

In Guideline 8(c) of Staff's Straw Proposal, Staff acknowledges that debt should be considered in the second round of the bid evaluation process. PacifiCorp appreciates Staff's recognition that debt plays an important role in the bid evaluation process. Implicit in this recognition is also a recognition that direct[1] and imputed debt can impose a real cost on PacifiCorp's ratepayers that should be factored into the resource evaluation process. PacifiCorp attaches hereto as Attachment B copies of the documents previously provided to the Commission for the June 8, 2005 technical conference on the debt issues. These documents explain the direct and imputed issues and demonstrate how PacifiCorp calculates the costs imposed by a PPA determined to impose direct or imputed debt.

PacifiCorp is concerned, however, with the problems that will arise by following Staff's proposal to wait to perform this analysis until the second round. If a cost is not accounted for in the initial round of the bid evaluation then the short-list that is produced from that analysis may not include the most economic resources. In other words, if Staff's proposal is adopted, PacifiCorp may have a short-list that does not represent the least cost options. After application of the debt equivalence costs in the final round, PacifiCorp may have included in the short-list bids that are less economic, than bids that did not make the short-list. In order to be fair to all bidders and to get the best value for PacifiCorp ratepayers, PacifiCorp would maintain that it would need to test the other bids that did not make the short-list to determine whether its original short-list still represents the most economic bids.

[1] Staff's Guideline 8(c) mentioned "debt imputation" only. PacifiCorp does not know whether Staff uses that term to refer to both the direct debt that is applied directly to PacifiCorp's books as a result of the application of accounting standards EITF 01-08 and FASB 13 *and* the imputed debt that is recognized by rating agencies to take into account the debt-like qualities of power purchase agreements (and in fact, all other similar type agreements, not unique to the utility industry) after application of a risk factor, or to just one or the other. Both direct and imputed debt imposes real costs on the Company and its ratepayers. PacifiCorp believes that both types of debt equivalence should be taken into account in the bid evaluation and analysis. Accordingly, one of the changes in the proposed language in this section is to make clear that the Guideline is referring to both direct and imputed debt.

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In other words, following Staff's recommendation of not taking the debt equivalence issue into account results in one of two possibilities. Either PacifiCorp waits until the second round but then also evaluates the other bids to ensure it has the best short-list (a result that is equivalent to simply performing this analysis in the initial round as proposed by PacifiCorp) or PacifiCorp simply accepts the short-listed bids, applies any applicable debt costs and ignores the possibility that a more economic bid now resides in the category of bids no longer being considered. PacifiCorp submits that a more rational approach, which is consistent with Staff's recognition of debt as a real issue that should be taken into account, is to consider debt equivalence in the context of evaluating all bids in the first round, while putting the short-list together.

G. Guideline 9: RFP Design

PacifiCorp requests that the Commission replace the terms "Standard RFP" and "Non-Standard RFP" with the more descriptive terms "RFP without Benchmark Resource" (e.g., no utility self-build or ownership option) and "RFP with Benchmark Resource" (e.g. with utility self-build or ownership option).[2] PacifiCorp submits that the use of the terms "Standard RFP" to refer to RFPs conducted without a self-build or ownership option and "Non-Standard RFP" for RFPs with utility ownership options convey no meaningful information to the marketplace about the structure of the RFP and may in fact inappropriately suggest a negative connotation to the marketplace regarding RFPs with utility ownership options. Similar conforming amendments should be made throughout the document as proposed by PacifiCorp in Attachment A.

[2] PacifiCorp has carefully noted in these Comments that the reference to Benchmark Resource as currently used in the Guidelines seems to refer only to utility self-build or ownership options. However, PacifiCorp notes that even in the "RFP without Benchmark Resource" option, bids will still be evaluated against a "benchmark" which can be the market or other market options (as opposed to self-build or ownership options) to determine if the bids are economic. The terms should therefore not be read to mean that no comparison to other market options will be made in the RFP without Benchmark Resource category.

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H. Guideline 10: Minimum Bidder Requirements

PacifiCorp does not understand the intent of Staff's proposed guideline for minimum bidder requirements. In Order 91-1383, the Commission made clear that it was its intention that utilities should take into account in the RFP process, the credit and capability of prospective bidders in order to protect ratepayers. Specifically, Order 91-1383 states:

> "The RFP should clearly state the utility's policy regarding the project security requirements. In order to protect itself and ratepayers, the utility should require assurances that a proposed project has a reasonable probability of successful construction and operation. In determining this probability, such factors as the developer's control over the site where the project is to be located, project engineering, project financing, management expertise and the likelihood of obtaining necessary government licenses should be considered. The utility's RFP should clearly specify all information which should be included in a project sponsor's bid proposal. In addition, the utilities' requirements concerning entry fees, project milestones, and other project performance criteria which it feels necessary should also be listed in the RFP." (Order 91-1382 at 11).

If it is Staff's intent that this articulated Commission policy remains in tact and Staff Guideline 10 serves only to establish the vehicle by which utilities would propose minimum bidder requirements and those would be reviewed by the IE, the Commission and parties, then PacifiCorp has no objection to the proposed language so interpreted. If however, the intent of Staff's Guideline 10 is to remove this foundation as a general Commission policy and leave open the possibility that in each future RFP parties could argue that minimum bidder requirements are not necessary, PacifiCorp must object. For all of the reasons previously articulated by the Commission in Order 91-1383, it is imperative that PacifiCorp be permitted to employ minimum bidder requirements to ensure that the bidder has the capability to construct a project consistent with standard utility practices meeting its commercial operation date as required under the RFP and that the bidder offers sufficient credit protections to protect the ratepayers against the possibility that the project is not on-

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line. PacifiCorp's proposed language is intended to summarize, but not alter the meaning of the principle articulated by the Commission in Order 91-1383.

PacifiCorp does not object to the portion of the Guideline that would require that the IE review and analyze the reasonableness of minimum bidder requirements or that parties can comment on and that the Commission must approve the requirements.

I. Guideline 13(b)(iii): RFP Process/Analysis

In Guideline 13(b)(ii), Staff addresses the IE's role in evaluating non-standard RFPs. Specifically, Staff proposes that the "IE evaluates the unique risks and advantages associated with the Benchmark Resource . . . ." Again, PacifiCorp believes there is some ambiguity in this language and its comments may be resolved simply by Commission interpretation of this statement. As discussed in its UM 1056 comments, PacifiCorp believes that the utility, with input from the public and the Commission, should include a generic discussion of the benefits and risks of ownership versus purchasing in its IRP (not with respect to specific resources but as a general matter). Therefore, the utility, instead of the IE, should conduct this Benchmark Resource evaluation in the first instance. The IE would then evaluate the reasonableness of the proposed criteria, suggest any changes and then evaluate the reasonableness of utility's application of the criteria to the Benchmark Resource. If the IE chooses to also conduct its own separate evaluation of the Benchmark Resource to confirm the utility's results, it may do so.

J. Guideline 14: IE Closing Report

PacifiCorp is supportive of the IE preparing a public report version of its involvement in the RFP process. However, given the competitive nature of the power market and generation development business, PacifiCorp does not agree that a report detailing bid scoring and evaluation results with detailed bidder and bid information should be made available to any entity other than the procuring utility, the Commission and their staff. "Non-bidding consumer advocates" may include entities that could use the information to the

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commercial disadvantage of bidders or the utility. Instead, PacifiCorp suggests that the Commission recognize that disclosure to a wider group of intervenors may require the use of heightened protective procedures and/or redaction of sensitive information so as to protect the bidders' competitively sensitive information and market position.

K. Guideline 15: Confidential Treatment of Bid and Score Information

PacifiCorp has the same confidentiality concerns with this Guideline as it did with respect to Guideline 14 and therefore, recommends similar changes to the Guidelines.

III. COMMENTS IN RESPONSE TO COMMISSION'S LIST OF ISSUES

In the June 6 ALJ Memorandum, the Commission identified five areas of the competitive bidding process that the Commission was particularly interested in: (1) the treatment of a utility or the utility's affiliates in the bidding process, (2) the Commission's role in reviewing competitive bids, (3) the criteria to be used in scoring a bid, (4) the role of an independent monitor or evaluator (the "IE"), and (5) the use of an auction process. Staff's Straw Proposal does not fully capture PacifiCorp's view of (2) the role of the Commission in reviewing competitive bids, and does not address issue (5) the use of an auction process. The following comments address those two issues.

A. What Should Be the Commission's Role in Reviewing Competitive Bids?

In the June 6 ALJ Memorandum, the Commission stated that it was interested in what its role should be in reviewing competitive bids. PacifiCorp is comfortable with Staff's delineation of the Commission's role as set out in Guidelines 16 (RFP Acknowledgement) and 13 (RFP Process/Analysis) of Staff's Straw Proposal. However, PacifiCorp would like to submit further clarifying points on this issue.

Overall, it is PacifiCorp's position that the role of the Commission in the competitive bidding process should remain generally unchanged from its role as set out in Order 91-1383. In Order 91-1383, the Commission stated that its role in the competitive bidding process was to review the RFP for compliance with the order and for consistency with the utility's IRP.

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The Commission also cautioned that it "will not concern itself with substantive terms or technical details of an RFP for other purposes."

Consistent with Order 91-1383, PacifiCorp believes that the Commission's review of the draft RFP should include providing feedback to the utility regarding any concerns the Commission may have, as well as guidance about what would be a reasonable way of moving forward. PacifiCorp would welcome any feedback the Commission could provide, because it is PacifiCorp's view that the Commission's concerns about an RFP are best identified and addressed early. PacifiCorp has proposed one minor change to Guideline 11 to reflect the Commission's role in approving the draft RFP.

Second, the Commission should resolve any disputes that may arise regarding bid interpretation that cannot be resolved with the IE, utility and bidders during the evaluation process on an expedited basis pursuant to the Commission's complaint process under ORS 756.500 and OAR 860-13-015. PacifiCorp expects that the IE should make every effort to resolve any such dispute as the liaison between the utility and the bidder; however, in the event the dispute cannot be resolved, the Commission's input may be required.

Third, the Commission should acknowledge the results of the RFP. As set out in Guideline 16 of Staff's Straw Proposal, Commission acknowledgement shall have the same meaning as assigned to that term in Commission Order 89-507.

B. Is There Any Role Now, or in the Foreseeable Future, for Use of an Auction Process?

PacifiCorp does not believe that an auction process is a reasonable approach at the current time or in the foreseeable future based on the types of markets that exist in the Pacific Northwest. An auction process exists and functions well in organized markets where the market is trading standard products under standard contracts (terms and conditions). Given the fact that the market is trading standard products with standards contracts, the only relevant factor in determining the winning bid in an auction process is price.

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While the market trades forward actively in the short and near-term, as discussed above, utilizing standard products under standard Western System Power Power and Edison Electric Institute that same type of standard product does not exist for longer-term and larger products, such as are involved in acquiring a Major Resource. Accordingly, utilizing an auction process based solely on price would not work in the context of competitive bidding for Major Resources in the Pacific Northwest markets because relying solely on price would not provide for an appropriate comparison of all of the potential differing factors due to the complexity of the underlying agreements that provide the terms and conditions of the transactions.

IV. CONCLUSION

PacifiCorp agrees with the general framework established by Staff to address revisions to the competitive bidding process. Nevertheless, for the reasons set out above, PacifiCorp disagrees with Staff's Straw Proposal on several significant points and requests that the Commission accept PacifiCorp's proposed amendments to Staff's Straw Proposal.

DATED: September 30, 2005.

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STAFF Straw Proposal
Docket No. UM 1182
Competitive Bidding Investigation
September 26, 2005

1. **RFP after IRP:** The RFP process should generally follow the IRP process. ~~If the utility's IRP shows new resources are needed, then the utility's IRP Action Plan should identify the preferred resource strategy, specifically describing the types of technologies and characteristics of each new resource in the utility's preferred resource portfolio. For each of the resources identified in its IRP Action Plan, the utility should indicate if it plans to consider a utility-owned resource. If the utility plans to consider a utility-owned site it should identify the transmission arrangements.~~ If circumstances require a utility to conduct a competitive bidding process prior to IRP acknowledgment, the utility should explain such reasons in its draft RFP.

2. **RFP Requirement:** Utilities must issue RFPs for all Major Resource acquisitions. Major Resources are resources with durations greater than ~~5~~ 10 years and quantities greater than ~~50~~ 100 MW.

~~3. **Exceptions to RFP Requirement:** The RFP requirement does not apply to Major Resource acquisitions, other than self-build resources, in emergencies or in situations where there is a time-limited resource opportunity of unique value to customers. If a utility acquires a Major Resource under such conditions, it shall report the acquisition and the reason for acting outside of the RFP requirement to the Commission, within 30 days of the acquisition. Copies of the report will be served on all participants in the utility's most recent RFP and IRP processes as well as on parties to its most recent rate case.~~

~~4~~3. **Waiver of RFP Requirement:** ~~A utility may request Commission acknowledgment of an alternative acquisition method for a Major Resource in the utility's IRP.~~ A utility may ~~also~~ request ~~a~~ that the Commission grant a waiver ~~outside the IRP process~~ for Major Resource acquisitions. A waiver may be granted upon a finding of an emergency situation, a time-limited resource opportunity or other showing that the public interest requires such a waiver. Such request will be served on all participants in the utility's most recent RFP and IRP processes, as well as on parties to its most recent general rate case. The Commission will issue an Order addressing such requests within 120 days, or earlier, if the Commission finds that good cause exists for an expedited process, taking such oral and written comments as it finds appropriate under the circumstances.

5. **Affiliate Bidding:** Utilities may allow affiliates to submit RFP bids. If the utility allows affiliate bidding, then an Independent Evaluator must participate in

the ~~Non-Standard~~ RFP with Benchmark Option. The utility must blind all RFP bids and treat affiliate bids the same as all other bids.

6. Utility Ownership Options: Utilities may use a self-build option as a Benchmark Resource in an RFP to provide a cost-based alternative for customers. Utilities may also consider ownership transfers within an RFP solicitation. If the utility intends to consider ownership options in an RFP, then an Independent Evaluator must participate in the ~~Non-Standard~~ RFP with Benchmark Option.

7. Independent Evaluator (IE): The utility and Commission staff select an IE from a qualified slate of candidates. The IE must demonstrate sufficient qualifications, expertise and experience to perform all of the functions of the IE as contemplated by the Commission and these Guidelines. Specifically, the IE must be independent of the soliciting utility and likely, potential bidders and also be experienced and competent to perform all functions of the IE as contemplated by this Commission and these Guidelines. ~~The IE should not be providing, or recently have provided, consulting services to participants in western energy markets. The IE should report to the Commission staff.~~ The IE should be paid by the utility through assessments of all bidders ~~including the utility~~. The bidding fees will be based on the anticipated costs of the IE's services as established between the IE and the Commission staff.

8. Bid Scoring and Evaluation Criteria:

a. Selection of an initial short-list of bids should be based on price and non-price factors. The utility should use the initial prices submitted by the bidders to determine each bid's price score. The price score should be calculated as the ratio of the bid's projected total cost per megawatt-hour to forward market prices using real-levelized or annuity methods. The non-price score should be based on resource characteristics identified in the utility's IRP Action Plan (e.g., dispatch flexibility, resource term, portfolio diversity, etc.) and conformance to the standard form contracts attached to the RFP.

b. Selection of the final short-list of bids should be made on a system basis using the utility's production cost and risk models to identify the least-cost, least-risk combination of resources. The portfolio modeling and decision criteria used to select the final short-list of bids must be consistent with the modeling and decision criteria used to develop the utility's IRP Action Plan. If an IE is used, then the IE will have full access to the utility's production cost and risk models.

c. Consideration of ratings agency debt imputation and direct debt should be ~~reserved for the selection of the final bids from~~ included during the initial ~~short-list of~~ evaluation of all bids. The Utility should be willing to obtain an advisory opinion from a ratings agency to substantiate its analysis and final decision, if requested by the Commission.

9. RFP Design:

a. ~~Standard~~ RFP without Benchmark Resource: The utility designs and conducts a "~~Standard~~ RFP without Benchmark Resource" if it will not consider affiliate bids or ownership options in the RFP.

b. ~~Non-Standard~~ RFP with Benchmark Resource: If the utility intends to consider self-build, affiliate, or ownership options in the RFP it must conduct a "~~Non-Standard~~ RFP with Benchmark Resource" and use an Independent Evaluator.

c. Public Process Regarding RFP Design: Not less than 60 days before the utility intends to conduct a ~~Standard or Non-Standard~~ RFP with or without Benchmark Resource, the utility should announce its intention to conduct an RFP. The utility should draft a "~~Standard~~ RFP without Benchmark Resource" proposal, including the scoring and bid evaluation criteria. If a utility self-build, affiliate, or ownership option is considered, the utility and the IE together should draft a "~~Non-Standard~~ RFP with Benchmark Resource." The utility and the IE, as needed, may conduct workshops on the upcoming RFP and will submit its final proposed RFP, including bid evaluation and scoring criteria and standard form contracts, to the Commission for approval, as described in paragraph 11 below.

10. Minimum Bidder Requirements: In order to protect itself and ratepayers, the utility should require assurances that a proposed project has a reasonable probability of successful construction and operation including such factors as project security, site control, engineering, financing, expertise and likelihood of obtaining licenses. To satisfy this requirement, ~~T~~the utility may propose minimum bidder requirements for credit and capability. If a ~~Non-Standard~~ RFP with Benchmark Resource is used, then the IE should assist in the development of any minimum bidder requirements. Minimum bidder requirements will be subject to public comment during the design of the RFP and to Commission approval of the proposed RFP as described in paragraph 11 below.

11. RFP Approval: The Commission should solicit public comment on the utility's draft RFP, including the proposed minimum bidder requirements and bid scoring and evaluation criteria. Public comment and Commission approval should focus on: (1) the alignment of the utility's draft RFP with the utility's IRP; (2) whether the draft RFP satisfies the Commission's competitive bidding guidelines; and (3) the overall fairness of the proposed RFP process. After reviewing the draft RFP and the public comments the Commission may approve the RFP with any conditions and modifications deemed necessary. The

Commission should consider the impact of multi-state regulation including requirements imposed by other states for the RFP process, such as the timing of the process and the selection and use of an IE. The Commission should act on the proposed RFP within a reasonable time, but no later than 45 days following the filing of the final proposed RFP, unless the utility requests additional time.

12. Benchmark Score: If a utility owns a site that it intends to use as a Benchmark Resource in a ~~Non-Standard~~ RFP with Benchmark Resource, the utility must submit a detailed Benchmark Score, with supporting cost information, to the Commission and IE prior to the opening of bidding. The Benchmark Score should be assigned to the Benchmark Resource using the same bid scoring and evaluation criteria that will be used to score market bids. Information provided to the Commission and IE must include any transmission arrangements and all other information necessary to score the Benchmark Resource. If, during the course of the RFP process, the utility and IE determine that bidder updates are appropriate, the utility will also update the costs of the Benchmark Resource. The IE will review the reasonableness of the cost update and the revised Benchmark Score. The information provided to the Commission and IE will be sealed and held until the bidding in the RFP has concluded.

13. RFP Process/ Analysis:

a. ~~Standard~~ RFP without Benchmark Resource: The utility conducts the RFP process, scores the bids, selects the initial and final short-lists, and undertakes negotiations with bidders.

b. ~~Non-Standard~~ RFP with Benchmark Resource:

   i. The utility conducts the RFP process, scores the bids, selects the initial and final short-lists, and undertakes negotiations with bidders.

   ii. The IE validates the utility's Benchmark Score and may validate, sample, or independently score all bids, at the discretion of the IE and the Commission. In addition, the utility must include the criteria and evaluation of ~~IE evaluates~~ the unique risks and advantages associated with the Benchmark Resource, including the regulatory treatment of construction cost overruns, equipment failures and outages, costs of replacement capacity, energy and ancillary services, and other risks and advantages of the Benchmark Resource to consumers. The IE must validate the criteria used to evaluate the Benchmark Resource and the evaluation of the Benchmark Resource.

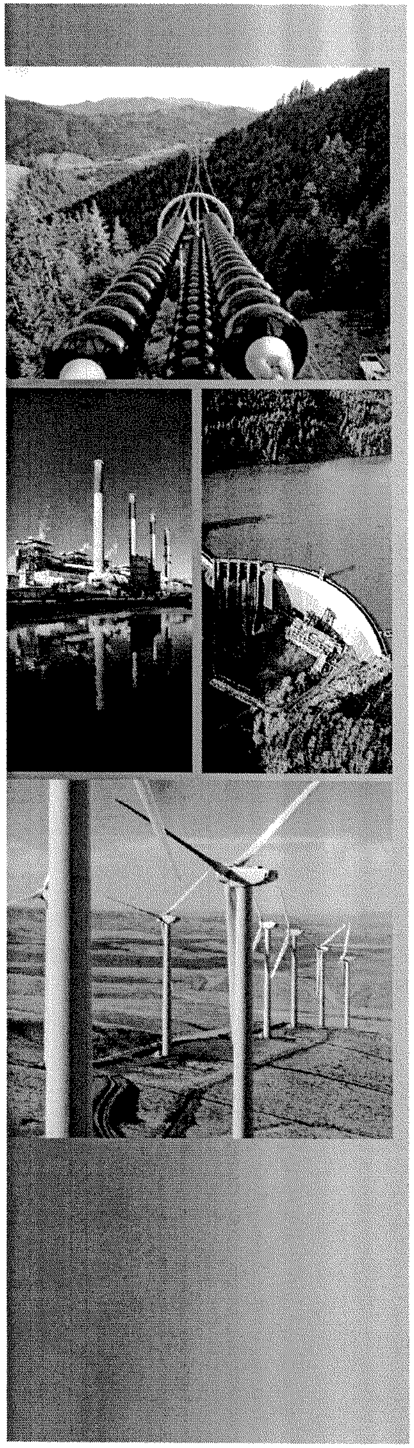
   iii. ~~Once the competing bids and Benchmark Resource have been scored and evaluated by the utility and the IE, the two should compare results.~~ The utility and IE should work to reconcile and resolve any scoring differences.

14. IE Closing Report: The IE will prepare a Closing Report for the Commission once it has completed its involvement in the RFP process. In addition, the IE will make its detailed bid scoring and evaluation results available to the utility, Commission staff, and ~~non-bidding consumer advocates~~ the Commission subject to the terms of a protective order. A copy of the report will also be made available to non-bidding consumer advocates with bidder information blinded by the IE subject to the terms of a protective order.

15. Confidential Treatment of Bid and Score Information: Bidding information, including the utility's cost support for its Benchmark Resource, as well as any detailed bid scoring and evaluation results will be made available to the utility, Commission staff, and ~~non-bidding intervenors~~ the Commission under protective orders that limit use of the information to RFP acknowledgment or cost-recovery proceedings in which the RFP resources are at issue. This information will also be made available to non-bidding intervenors with bidder information blinded by the IE subject to the terms of a protective order.

16. RFP Acknowledgment: The utility may request that the Commission acknowledge the utility's selection of the final short-list of RFP resources. The IE will participate in any RFP acknowledgment proceeding. RFP acknowledgment should have the same legal force and effect as IRP acknowledgment in any future cost-recovery proceeding in which the selected resources are at issue. Acknowledgment shall have the same meaning as assigned to that term in OPUC Order No. 89-507.

ATTACHMENT B



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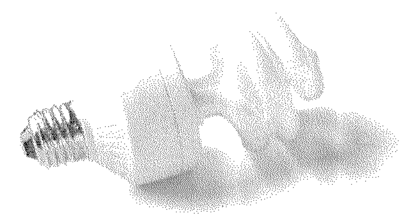
Direct and Inferred Debt

June 8, 2005



Accounting Agenda

- Guiding Principles

- Terms of Reference
  - Definitions

- Lease Accounting flow diagram

- Rebalancing costs associated with debt examples.
  - FIN46 – consolidation onto balance sheet (direct debt & equity)
  - Capital lease – minimum rents (direct debt)
  - Capital or Operating lease – no minimum rents (may result in zero debt)
  - Operating lease – minimum rents (S&P imputed debt)
  - Executory contracts – all-in energy & capacity payments (S&P imputed debt)

- Conclusions and Next steps

Overview

- Guiding Principles
  - Costs should be included in the decision process
    - unfair to ratepayers if all known costs are not included in resource decisions
    - equity has a cost, this cost needs to be taken into account when evaluating bids
  - Rebalancing costs associated with debt are real costs to a utility and will impact cost to ratepayers if we do not charge bidders appropriately.
  - Who should bare the cost and when
    - Rebalancing costs associated with debt needs to be included when determining the initial shortlist otherwise adding costs at a later date may result in **not** selecting the least cost resource.
    - These costs must be considered with **each** resource decision otherwise the last resource triggers the requirement of infusing the equity to rebalance the portfolio and incurs all of the the cost instead of its portion which most likely will render the last resource uneconomical.
- Recovery Mechanism
  - Discussion today is focused on rebalancing costs associated with debt, not on a proposed recovery mechanism (s).

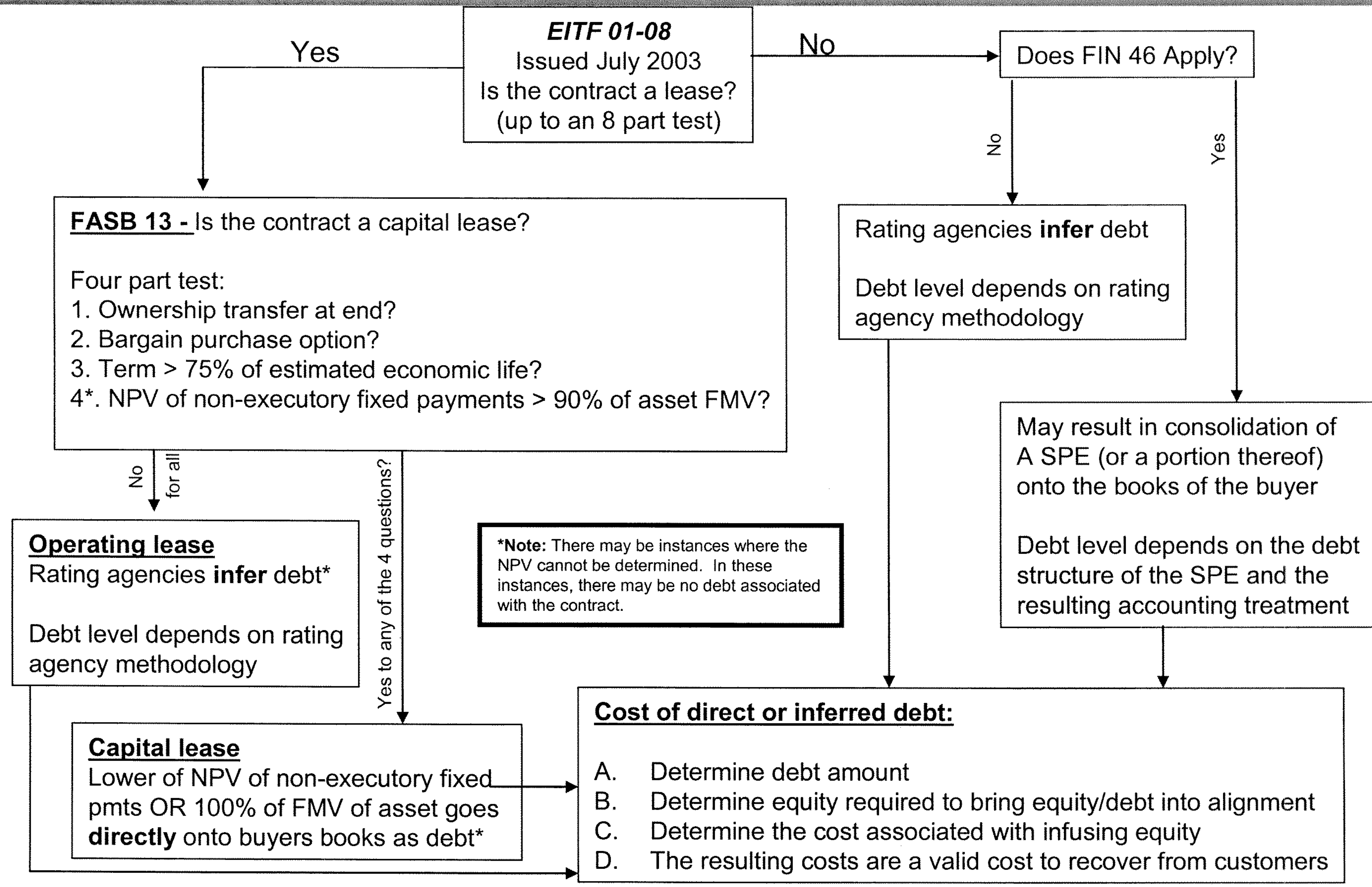
Terms of Reference

- Direct Debt - results when a contract results in a Capital Lease pursuant to EITF 01-08 and SFAS no. 13 resulting in the lower of the Net Present Value of the non-executory minimum lease payments or 100% of the fair market value of the asset going directly on the Utility balance sheet as debt.

- Inferred Debt – results when credit ratings agencies infer an amount of debt associated with a power supply contract and, as a result, take the added debt into account when reviewing the Utility's credit standing.

- In both instances, Direct or Inferred Debt, the Utility will be required to inject equity to maintain the same debt/equity ratio as before the power supply contract.
  - Equity has a cost, this cost needs to be taken into account when evaluating bids from the customers perspective in the even of both a Capital or an Operating lease
    - Capital Lease - the debt associated with each contract is determined at the beginning of the contract as the amount the Utility must place on its balance sheet as a result of a Capital lease.
    - Operating Lease – the inferred debt will be determined utilizing the methodology used by S&P. At the beginning of the contract, the NPV of the remaining fixed payments will be calculated using a 10% discount and then multiplied by a "risk factor" (varies from 30-50%).

Lease Accounting ➔ Cost of Direct/Inferred Debt



FIN46 – consolidation onto balance sheet (direct debt & equity)

- Contract not determined to be a capital or operating lease but we are determined to be the "primary beneficiary" under FIN 46R (did not trigger any EITF 01-08 tests).
- Example: long-term contract calls for us to purchase of 80% of output of a power plant (therefore not a lease). Builder of plant is shelled in an LLC structure where the primary backing for the debt used to finance the asset is the PPA. The LLC has no other assets of substance and was formed to house the construction of the plant.
- The primary beneficiary tests to be applied under FIN 46R are very complicated but are intended to capture "off balance sheet" obligations that may not otherwise be picked up.
- Cost of equity infusion, if applicable, is dependent upon a variety of items associated with the consolidated entity's capital structure and cost of capital relative to PacifiCorp's capital structure and cost of capital.

Capital lease – minimum rents (direct debt)

- Capital lease designation per FASB 13 test
  - Minimum payments can be established, resulting in ability to calculate direct debt resulting from a given deal.
  - Capital lease example - debt determination & cost of equity infusion:
    - 20 yr power/gas toll - 200 MW.
    - Escalating capacity pmts ($6.54/KW-mo starting), with executory costs at 20% of capacity pmt.
    - $844/KW cost to build, 6% incremental cost of 20 yr debt.
    - 50/50 debt/equity ratio, pre-tax required equity return 17%, pre-tax WACC 11.5%.
- Direct debt = Lower of present value @ 6% of 80% of capacity pmts, OR fair market value (cost to build utilized as proxy).
    - $205m PV 80% pmts VS $169m FMV. Direct debt = **$169m**
  - $169m direct debt requires $169m infusion of equity, assuming 50/50 D/E ratio.
  - Equity infusion cost to be calculated on spread between pre-tax equity return versus pre-tax WACC.
    - 5.5% spread applied to equity infusion. Debt & resulting equity infusion value decreases yearly.
    - Present value of revenue requirement associated with "interest expense", based on 5.5% spread applied to decreasing yearly equity levels.
    - Cost of equity infusion = PV of "interest expense" = **$68m**

Capital or Operating lease – no minimum rents
(may result in zero debt)

- Contract meets criteria in EITF 01-8 and it is determined a lease exists.

- Analysis shows payments are "contingent rents" under FAS 13.

  - Contract has no set capacity payment and specifies only a mechanical availability guarantee. Results in payments only being made based on level of output.

  - Contract has no set capacity payment and no specified volumetric output guarantee or mechanical availability guarantee. Results in payments only being made based on level of output.

  - Contract contains stated expected output but is silent on guaranteed output and has no liquidating damage provisions which may set an implied minimum. Results in payments only being made on level of output.

- It should be noted that it is both resource type dependent and rare for a Capital or Operating lease contract to have no minimum rents, and as a result, zero debt.

Operating lease – minimum rents (S&P imputed debt)

- Operating lease designation per FASB 13 test

- Operating lease example - debt determination & cost of equity infusion:
  - 20 yr power/gas toll - 200 MW w/ escalating capacity pmts ($6.54/KW-mo starting).
  - 50% S&P Risk Factor, 10% S&P Discount Rate
  - 50/50 debt/equity ratio, pre-tax required equity return 17%, pre-tax WACC 11.5%.

  - Imputed debt = Present value @ 10% of 50% of capacity pmts.
    - **$94m PV**

  - $94m imputed debt requires $94m infusion of equity, assuming 50/50 D/E ratio.
  - Equity infusion cost to be calculated on spread between pre-tax equity return versus pre-tax WACC.
    - 5.5% spread applied to equity infusion. Debt & resulting equity infusion value decreases yearly.
    - Present value of revenue requirement associated with "interest expense", based on 5.5% spread applied to decreasing yearly equity levels.
    - Cost of equity infusion = PV of "interest expense" = **$38m**

Executory contracts – all-in energy & capacity payments (may result in S&P imputed debt)

- Contract does not meet criteria in EITF 01-8 and is determined not a lease.
- Contract does contain fixed all-in energy & capacity payment.
- Executory contract example - debt determination & cost of equity infusion:
  - 20 yr 7x16 forward purchase - 200 MW w/ escalating energy pmts ($40/MWh starting).
  - 50% energy/capacity split, 50% S&P Risk Factor, 10% S&P Discount Rate.
  - 50/50 debt/equity ratio, pre-tax required equity return 17%, pre-tax WACC 11.5%.

  - Imputed debt = Present value @ 10% of 50% of capacity pmts.
    - **$125m PV**

  - $125m imputed debt requires $125m infusion of equity, assuming 50/50 D/E ratio.
  - Equity infusion cost to be calculated on spread between pre-tax equity return versus pre-tax WACC.
    - 5.5% spread applied to equity infusion. Debt & resulting equity infusion value decreases yearly.
    - Present value of revenue requirement associated with "interest expense", based on 5.5% spread applied to decreasing yearly equity levels.
    - Cost of equity infusion = PV of "interest expense" = **$49m**

Conclusions and Next Steps

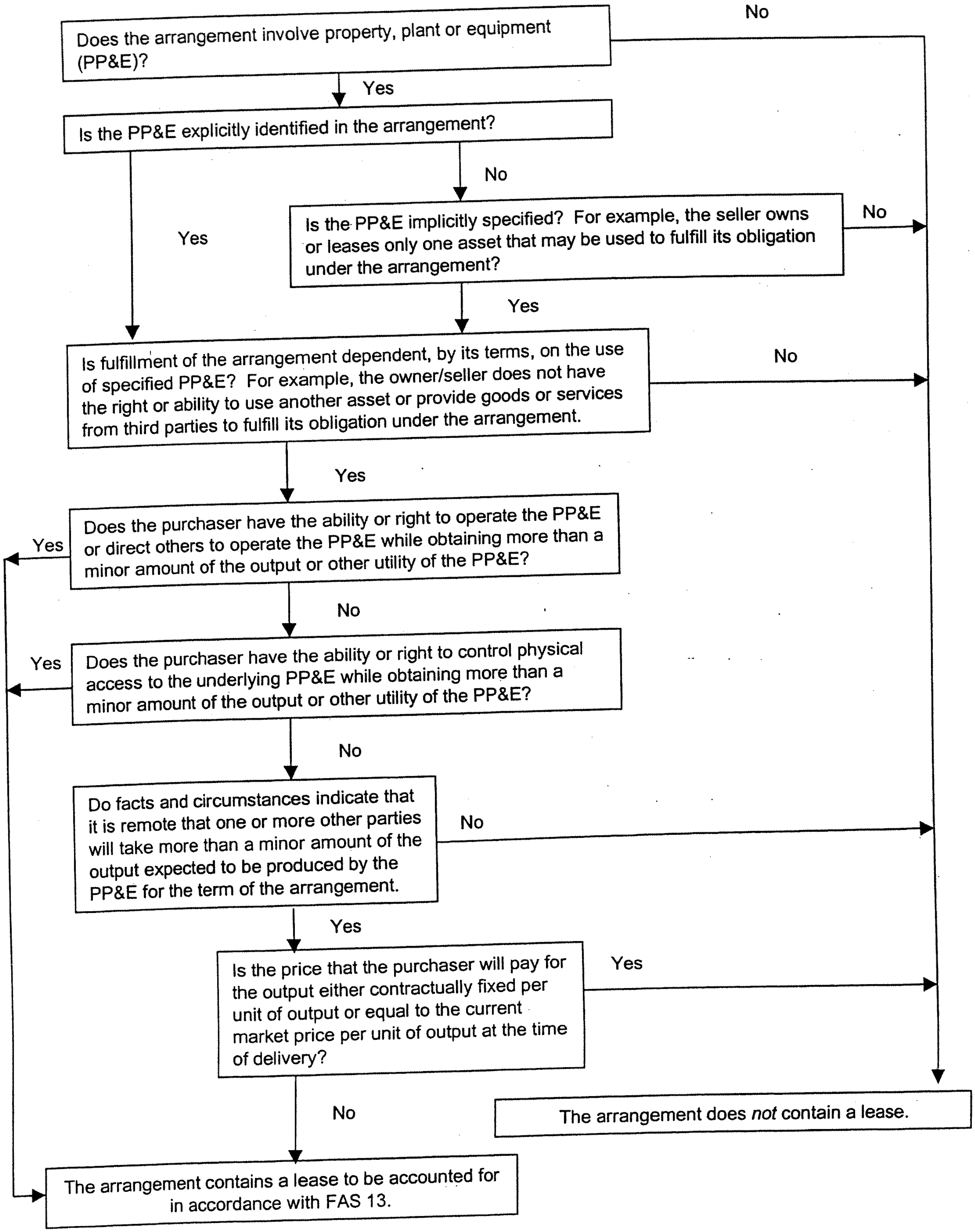
- Conclusions
  - Rebalancing costs associated with debt are true costs
    - Inferred Debt – credit rating agencies associated with PPAs
    - Direct Debt – debt is added directly to a PPA buyer's balance sheet as a result of lease accounting

- Cost will be added to as part of the evaluation on each resource decision.
  - In the event of an Request for Proposal the cost needs to be a part of the initial shortlist in order to account for all the costs in deriving least cost resources.

- Rebalancing costs associated with debt are real to a utility and will impact cost to ratepayers

- Next Steps
  - To discuss proposals to address recovery mechanisms

Appendix A – Flowchart Illustration of the EITF 01-8 Model to Determine Whether an Arrangement Contains a Lease
(Intended only to be used as a supplement, not in lieu of, to the guidance in EITF 01-8)



"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

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[M]ay 8, 2003

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. *(see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002)*. The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be

Table 1

ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2

ABC Utility Co. Adjustment to Pretax Interest Coverage

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build—i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%—10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (11 plus 48). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means.

<u>Debt Determination and Cost for Contracted Power Supply</u>

General:
A PPA or other power supply contract can result in **<u>direct debt</u>** (via lease accounting pursuant to EITF 01-08 and FAS No. 13) or **<u>inferred debt</u>** (via rating agency debt inference). Returning to the pre-contract debt/equity ratio requires more equity. Equity has a cost associated with it and, as a result, the following calculation should be performed for any PPA > 3-years in term to quantify this cost.

Definitions:

- PPA - Power Purchase Agreement

- FMV – Fair Market Value. FMV is the current market value of an asset. Since this is rarely known, the FMV should be assumed to be the cost the buyer expects it would incur to construct a comparison asset.

- NPV – Net Present Value of a stream of cash flows at a given discount rate.

- S&P Debt – The debt that rating agencies (S&P in this case) are anticipated to infer due to an applicable PPA or contract. S&P Debt is determined by taking the NPV (at a 10% discount rate) of the capacity component of the payments and multiplying it by a risk factor. The generic risk factor that S&P uses (for utilities with PPAs included as an operating expense in base tariffs) is 50%[1]

  [**note:** The risk factor can be lower, 30% for example, for utilities that have effective power cost adjustment mechanisms (PCAMs)].

- WACC – Weighted Average Cost of Capital.

- IncEquity1 - incremental equity due to **direct debt** from lease accounting or consolidation under FIN-46, if applicable.

- IncEquity2 – incremental equity due to rating agency **inferred debt**, if applicable.

Cost Calculation:
Assuming the minimum debt/equity split allowed by regulators (which translates to a maximum WACC allowed) is 50/50, a cost of debt of 6.91% and an allowed return on equity of 17.2%[2], the maximum WACC allowed would be 12.055% (0.5*.0691+0.5*.172). [**note:** The actual debt/equity split, as well as actual cost of debt, common equity, and preferred equity should be used for analysis purposes]

> Annual Debt-Related Cost = (17.2% - 12.055%) (higher of IncEquity1 or IncEquity2) where;
>
> IncEquity1 = MAX [Equity Infusion Required, 0], where;
>
> Equity Infusion Required = MIN [(NPV Non-Executory Payments[3] ÷ Pre-PPA Debt-to-Asset Ratio) X (Pre-PPA Equity-to-Asset Ratio), FMV ÷ (Pre-PPA Debt-to-Asset Ratio) – FMV]
>
> IncEquity2 = MAX [(S&P Debt ÷ (Pre-PPA Debt-to-Asset Ratio)) X (Pre-PPA Equity-to-Asset Ratio)), 0]

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[1] A risk factor as low as 30% could be used for utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs. In certain cases, S&P may consider a lower risk factor of 10-20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. A risk factor for PURPA qualifying facilities may be assumed to be between 10-30% depending on past recovery precedent. Reference October 2003 S&P article.
[2] Since preferred & common equity holders demand a weighted 10.7% after taxes in this case, the before tax rate needs to be grossed up to take into account the marginal tax rate of 37.95%. The before tax cost of equity should therefore be 17.2% (.107 ÷ (1-.3795)).
[3] Discount rate equal to buyer's incremental cost of debt for a like term and amount.

CERTIFICATE OF SERVICE

I hereby certify that I served a copy of the foregoing document upon the parties of record in this proceeding by first-class mail and electronic mail, addressed to said parties/attorneys' addresses as shown below:

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