PROJECT NO. 24365

RULEMAKING CONCERNING	**§**	**PUBLIC UTILITY COMMISSION**
ARRANGEMENTS BETWEEN	**§**	
QUALIFYING FACILITIES AND	**§**	
ELECTRIC UTILITIES	**§**	**OF TEXAS**

ORDER ADOPTING AMENDMENTS TO §25.242
AS APPROVED AT THE JUNE 6, 2002 OPEN MEETING

The Public Utility Commission of Texas (commission) adopts an amendment to §25.242 relating to Arrangements Between Qualifying Facilities and Electric Utilities, with changes to the proposed text as published in the January 4, 2002, *Texas Register* (27 TexReg 18). This amendment addresses the sale and purchase of electricity between qualifying facilities (QFs) and retail electric providers (REPs) with the price to beat (PTB) obligation (PTB REPs) in the restructured electric market that became effective on January 1, 2002. The amendment retains the applicability of the rule pertaining to arrangements between qualifying facilities and electric utilities in the parts of Texas in which the electric market has not yet been restructured. This amendment is adopted under Project Number 24365.

The federal Public Utility Regulatory Policies Act of 1978, Public Law No. 95-617, 92 Stat. 3117 (codified as amended in scattered Sections 815, 816, 842-43) (PURPA) gives QFs the right to sell (put) electricity to electric utilities at "avoided costs." A state agency is expected to implement this requirement for "each electric utility, for which it has rate making authority." 16 U.S.C. §824a-3(f)(1)(2000). PURPA defines "electric utility" broadly: "any person, State agency, or Federal agency, which sells electric energy." 16 U.S.C. §2602(4)(2000). In the restructured Texas market, both REPs and power generation companies (PGCs) are electric utilities for purposes of PURPA. *See* Public Utility Regulatory Act (PURA), Texas Utilities Code Annotated §31.002(10) and (17) (Vernon 1998 & Supplement 2002). However, the only entities that sell electricity in the restructured market over which the commission has ratemaking authority are PTB REPs and providers of last resort (POLRs), pursuant to PURA §39.202 and §39.106, respectively. The PTB REPs and POLRs began providing service on January 1, 2002. *See* PURA §39.102 and §39.202(a).

On May 17, 2001, the Federal Energy Regulatory Commission (FERC) issued an "Order Granting Declaratory Order and Denying Waiver of Regulations Implementing PURPA" in FERC Docket Nos. EL01-49-000 and EL01-60-000. The commission, in the FERC waiver docket, sought waiver from implementing PURPA upon the belief that an open, competitive market beginning on January 1, 2002 would render the PURPA power purchase obligations unnecessary in Texas. The FERC ruled that the commission must maintain its obligation to implement PURPA after unbundling and the commencement of competition and invited the commission to develop a market-oriented method of determining avoided costs consistent with PURPA and retail competition in Texas.

As part of the drafting process, commission staff conducted workshops in Austin to receive input from potentially affected persons on August 10, 2001, August 17, 2001, and March 13, 2002. Written comments from a number of interested parties were submitted in connection with these workshops. Although standard rulemaking procedures pursuant to Texas Government Code, Chapter 2001 were used without incorporating formal negotiated rulemaking procedures, commission staff nevertheless attempted to find areas of agreement among the parties during these workshops. The commission considered the draft rule for publication at the December 19, 2001 open meeting.

The commission received written comments on the proposed amendment on January 25, 2002 from Dynegy Power Inc., Calpine Corporation, Gregory Power Partners, L.P., and Conoco Inc. (collectively Texas QFs), Texas Industrial Energy Consumers (TIEC), Reliant Resources, Incorporated (RRI), American Electric Power Service Company (AEPSC), Entergy Solutions Select Ltd. and Entergy Solutions Essentials Ltd. (Entergy REPs), TXU Company LP (TXU), First Choice Power, Inc. (First Choice), Office of Public Utility Counsel (OPUC), and Brazos Electric Power Cooperative, Inc. (Brazos). On February 4, 2002, the commission received reply comments from Texas QFs, TIEC, RRI, AEPSC, Entergy REPs, and TXU. On March 27, 2002, the commission received further comments on issues concerning the commission's jurisdiction from Texas QFs, TIEC, RRI, AEPSC, Entergy REPs, TXU, and OPUC. On April 1, 2002, the commission received reply comments on the matter of the commission's jurisdiction from Texas QFs, TIEC, RRI, AEPSC, Entergy REPs, TXU, and OPUC. Texas QFs filed supplemental comments on April 5, 2002 and RRI filed reply comments to Texas QFs' supplemental comments on April 11, 2002.

The majority of the parties' comments generally focused on the jurisdiction of the commission to establish avoided cost rates for the PTB REPs and POLRs, and the lack of clarity in the phrase "market price" as the definition of the rate that jurisdictional electric utilities must pay qualifying facilities. Additional comments were submitted concerning the impact of the proposed rule on the competitive market and several parties addressed alternatives for the commission's consideration. The commission first addresses these broad considerations and then the comments on specific rule language. Due to the overlapping nature of the issues, arguments and rationale for decisions in this introductory section shall be deemed as considered under the specific rule sections.

General comments on the competitive market

AEPSC indicated that the commission should seek to implement competitive solutions rather than regulatory solutions whenever possible. They contended that the proposed rule does not fully embrace competitive solutions and thus places PTB REPs at a disadvantage. AEPSC stated that the proposed rule will distort the competitive market. AEPSC interpreted PURPA to say that an "electric utility" is an entity that sells electricity in Texas; therefore, all REPs, power-generating companies, electrical cooperatives, municipal utilities and power marketers are subject to PURPA's obligations. Because the proposed rule only applies to PTB REPs and POLRs, it places an unfair burden on them. AEPSC argued that PURPA, as enacted in 1978, no longer has any relevance to the Electric Reliability Council of Texas (ERCOT) market that exists today. PURPA was meant to encourage generation when electric monopolies also had monopsony power over energy purchases. The introduction of wholesale electricity competition eliminated this market power. AEPSC further commented that QFs will have the same opportunity to sell their power as any other generating company and mandating that PTB REPs and POLRs take their puts amounts to preferential treatment for the QF. To the extent that these puts displace purchases of energy from different generating companies, this will result in an inefficient allocation of resources. AEPSC finally argued that if for some reason, PURPA is repealed or otherwise rendered obsolete, any rules adopted by the commission addressing PURPA obligations should also be repealed.

The commission agrees with AEPSC that it should seek competitive solutions rather than regulatory solutions whenever possible. However, as discussed below, the commission finds that it has an obligation to implement PURPA and, for reasons of administrative efficiency and market certainty, chooses to adopt this rule. The commission adopts this rule with some modification to the definition of "market price" in order to provide a definition that is the closest proxy as possible to a market price. The commission agrees that if PURPA is repealed or otherwise rendered obsolete, the rule should be reconsidered.

Rule alternatives – contested case process, self-implementation, or ERCOT

Entergy REPs and TXU reasoned that federal law, citing to PURPA and *FERC v. Mississippi*, 456 U.S. 742, 102 S.Ct. 2126 (1982), rehearing denied Sept. 9, 1982, 458 U.S. 1131, 103 S.Ct. 15, permits the States to opt out of PURPA implementation or to implement through contested hearings to adjudicate disputes involving QFs. Thus, Entergy REPs argued, it is unnecessary to implement PURPA through the creation of an administratively-determined avoided cost rate and unnecessary to adopt the proposed rule. On the other hand, Texas QFs strongly encouraged the commission to adopt a rule of general applicability to enforce PURPA in Texas. Texas QFs noted that addressing the issues raised herein on a case-by-case basis through the contested hearings process would waste parties' resources. Texas QFs supported a two-step process, whereby the commission adopts a transitional avoided cost pricing methodology that relies on reasonable proxy for prices until a liquid, real-time market develops. At such time, the commission could re-evaluate its policies and regulations.

Generally, RRI argued that the proposed rule is unnecessary for the commission to fulfill its duties under PURPA. RRI argued that the commission's instruction, at its December 19, 2001 open meeting, that the ERCOT electric utilities, as defined by PURPA, continue fulfilling their mandatory purchase obligations at market prices until such time that this proposed rule becomes finalized should be left standing as guidance. RRI contends that such guidance to all electric utilities in Texas, including ERCOT, is all that is necessary in order for the commission to fulfill its PURPA mandates. RRI argued that the proposed rule is unnecessary in order to meet PURPA requirements because the restructured ERCOT market provides more opportunities for qualifying facilities to sell their power than were envisioned at the time PURPA was enacted. Essentially, RRI argued that the intent of PURPA – assurance of QF interconnection and other services from electric utilities and assurance of electric utilities' purchases of QF power – has been outpaced by the opening of the wholesale and retail markets in ERCOT. Thus, the restructured, competitive wholesale and retail ERCOT market provides QFs in Texas far superior sales opportunities than that allowed under regulated markets.

TXU, AEPSC, RRI, and Entergy REPs commented on self-implementation of PURPA. TXU argued that PTB REPs and POLRs are non-regulated entities, but if required to implement PURPA, they should be allowed to self-implement. AEPSC suggested that the commission adopt a rule that encourages electric utilities to self-implement PURPA, particularly addressing PTB REPs and POLRs, if necessary. RRI stated that it will comply with its PURPA obligation to self-implement by entering into mutually agreeable bilateral transactions for energy from QFs. Additionally, RRI argued that QFs could choose to exercise the PURPA put through bilateral agreements with any PURPA defined electric utility for as-available energy which reflects the market prices in the competitive power region. Consistent with this approach, RRI argued that the commission could endorse procedures that ensure economic efficiency of the competitive market. Entergy REPs commented that they support the position that REPs should self-implement their PURPA obligations and disagreed with the position that urges the commission to adopt the proposed rule amendments based on a finding of ratemaking authority over PTB REPs and POLRs.

Texas QFs argued that since January 1, 2002, REPs have self-implemented with consequences that most of the non-firm energy produced by 10,000 MegaWatt (MW) of QF energy in Texas has been shut-in since that date. Texas QFs argued that the "market price" definition will shut down cogeneration in Texas, in direct contravention of the goals of the U.S. Congress to produce energy efficiencies and fuel conservation through cogeneration, while decreasing reliance on fossil fuels. AEPSC objected to the Texas QFs' argument that their energy has been shut-in in ERCOT, noting there are many new market participants to whom QFs can now sell their power in addition to the traditional utilities.

Texas QFs' further commented that if the commission is required by PURPA to set an avoided cost rate for the PTB REPs and POLRs and fails to do so, it will be treating them as if they were non-jurisdictional electric utilities, which under PURPA §210(f)(2) are required to self-implement the FERC rules. The commission cannot assert jurisdiction over the PTB REPs and POLRs for purposes of implementing PURPA and then allow them to self-implement PURPA with respect to the avoided cost rate.

Texas QFs noted that the TXU and AEPSC REPs have already purported to illegally self-implement PURPA, and the rates they are using utilize a "lesser of" formula whereby QFs will never be paid more than the balancing energy price - in direct contravention of the FERC's rejection of the balancing energy ancillary service administered by ERCOT. AEPSC took issue with the Texas QFs' comments that self-implementation is illegal, pointing out that the Texas QFs failed to cite a single law or statue violated by self-implementation in the absence of commission action.

The commission finds that it has the obligation to implement PURPA and, thus will do so through this rulemaking rather than allowing self-implementation. The commission's instruction at its December 19, 2001 open meeting that the ERCOT electric utilities, as defined by PURPA, continue fulfilling their mandatory purchase obligations at market prices until this proposed rule becomes finalized was meant to be strictly transitional. The commission disagrees with RRI that the temporary implementation directed at the December 19, 2001 open meeting is all that is necessary for the commission to fulfill its

PURPA mandates and declines to keep such guidance in place as the method of PURPA implementation.

Federal law may allow the States to opt out of implementing PURPA; however, the States may choose to implement PURPA by several methods, including rulemaking. The commission chooses to continue implementation of PURPA through rulemaking. The commission agrees with Texas QFs that implementation on a case-by-case, contested proceeding hearing approach would waste parties' resources. Additionally, case-by-case determinations would severely tax the commission's resources in adjudicating such matters. The commission further agrees with Texas QFs that a two-step process whereby the commission adopts a transitional avoided cost pricing methodology that relies on a reasonable proxy for prices until a liquid, real-time market develops is reasonable and preferable. The commission finds that the best accommodation of as-available energy from a QF would be to have that energy delivered to a liquid spot market where QFs receive the market clearing price of energy at the time that they delivered. Relaxation or elimination of ERCOT's balanced schedule requirement would facilitate the development of a liquid spot market.

The second alternative proposed by AEPSC was for the commission to implement a market-based solution through ERCOT. AEPSC contended that if ERCOT were to establish a mechanism to accept all QF power, this would treat all electric providers fairly and energy would settle at an efficient price. OPUC suggested that ERCOT is better equipped to fulfill QF obligations. OPUC argued that ERCOT already procures and sells balancing energy. Should ERCOT relax its balancing schedule requirement, as it is considering, it would have the ability to auction QF power. However, TXU disagreed with AEPSC's and OPUC's alternative to implementing PURPA for PTB REPs and POLRs which is to require ERCOT to purchase all PURPA puts. TXU explained that ERCOT is not a PURPA utility which sells electric energy. Rather, ERCOT is an agent that acquires ancillary services on behalf of energy buyers and sellers in the ERCOT market. TXU is concerned that AEPSC's and OPUC's alternative would "completely destroy the paradigm of a limited-independent system operator that has been promoted by the market participants in ERCOT."

The commission finds that ERCOT cannot be required to purchase PURPA puts because ERCOT is not a PURPA utility, which is defined as an entity that sells electric energy. While ERCOT acts as an agent to acquire ancillary services on behalf of entities in the ERCOT market, it never takes title to the electric energy. Therefore, ERCOT is not a seller of electric energy, which is necessary to be defined as a PURPA utility obligated to purchase PURPA puts. The commission agrees with TXU and declines to impose PURPA put requirements on ERCOT.

Comments on jurisdiction

TXU, RRI, and AEPSC argued that the commission does not have ratemaking jurisdiction over PTB REPs and POLRs. In contrast, TIEC and Texas QFs commented that the commission has the jurisdiction to implement PURPA with respect to the PTB REPs and POLRs – electric utilities under federal law over which the commission has ratemaking authority.

RRI, TXU, and AEPSC argued that the Legislature clearly intended that all REPs, including PTB REPs and POLRs, be non-regulated entities. RRI asserted that as a result of restructuring in Texas and the redefinition of "electric utility" pursuant to Senate Bill 7, 76th Legislature, (SB 7), the commission does not have the type of ratemaking authority contemplated by PURPA over PTB REPs and POLRs. RRI disagreed that the commission's remaining ratemaking authority over REPs, under PURA, Chapter 39, as it pertains to the setting of the PTB fuel factor, is traditional cost of service ratemaking authority that would trigger the obligation to implement the PURPA mandates. Thus, RRI argued that the proposed rule should be rejected. TXU argued in a similar vein that the commission no longer has traditional cost of service ratemaking authority over PTB REPs and POLRs, but only has limited authority over rates charged through the fuel factor of the PTB and the authority to approve POLR rates. Likewise, AEPSC argued that although the commission sets the PTB fuel factor and POLR REP's rate, this does not resemble the traditional ratemaking authority in place at the time PURPA was passed. Without jurisdiction, AEPSC suggested that the commission decline to adopt the proposed rule.

RRI argued that the proposed rule asserts that the commission's limited authority over POLRs and PTB REPs, for PURPA purposes, also subjects these entities to general ratemaking authority. Per RRI, the commission's authority would go so far as to create a new entity not mentioned in PURA – PTB REP. RRI asserted that such action is not supported by, and is contrary to, PURA. RRI further asserted that the proposed rule ignores the fact that a single REP, as a single legal entity, can serve both PTB and non-PTB customers, as well as serve as a POLR. RRI stated that problematic consequences could ensue in that the proposed rule's stated limited commission authority over the PTB REP and/or POLR pricing would essentially become broader, general ratemaking authority over the entire entity, including the non-POLR and non-PTB REP that do not have PURPA obligations. In order to withstand the regulatory tension, RRI argued that the only alternative was for the proposed rule to require that separate entities perform separate functions. However, RRI asserted this is not required nor allowed by PURA, and such separation would impose burdensome and higher scheduling, accounting and settlement costs as reflected in PTB rates or the rates charged to POLR customers.

RRI and AEPSC further argued that no state law authority exists to provide the commission with the power to regulate PTB REPs and POLRs wholesale power purchases from QFs. RRI and AEPSC outlined the scope of the commission's power as a creature of the state, citing to the recent *PUC v. City Public Service Board*, 53 S.W.3rd 310 (Tex. 2001) which held that the commission only has those powers expressly conferred upon it by the Legislature and whatever powers that are reasonably necessary to fulfill its express functions or duties.

RRI, AEPSC, TXU, and Entergy REPs asserted that there is no express grant of authority upon the commission to direct how the PTB REPs and POLRs will purchase power. Further, RRI, AEPSC, and Entergy REPs argued that PURA §35.061, in and of itself, cannot provide the commission power to adopt and enforce rules encouraging power production. The authority must derive from other grants of state authority. The limited grants of authority in PURA, Chapter 39 over the narrow retail end of the REPs' business cannot be expanded to provide the commission power through PURA §35.061.

OPUC argued that some limited commission authority exists by inference and/or implication. OPUC asserted that the commission has the authority to ensure that ancillary services are reasonable pursuant to PURA §35.004(e). Additionally, OPUC points out that the commission has jurisdiction by implication by virtue of its oversight authority over the wholesale power markets contained in PURA §§39.157(a) (addressing market power abuses), 39.151(d) and (i) (oversight, review and delegation of authority to ERCOT), 39.252(d) and 39.262(a) (authority to review wholesale transactions that increase stranded costs).

AEPSC and RRI argued that authority may not be implied because it is not necessary in order for the commission to carry out its express duties. The Legislature through SB 7, and the commission through rules adoption, have developed a deregulated market that encourages economical production of electric energy from QFs and further satisfies PURA §35.061 without implying additional powers over PTB REPs and POLRs. Although the FERC addressed this issue in terms of whether to grant a waiver to the commission under federal law, the issue presented to the commission is one of state law – whether the commission need imply authority over PTB REPs and POLRs to encourage QF power production.

Texas QFs argued that until January 1, 2007, PTB REPs must offer the PTB, which was initially established by the commission, including the fuel factor incorporated therein. In addition, the commission has the authority to adjust the PTB up to twice a year for changes in the prices of natural gas and purchased energy. The commission also has exclusive jurisdiction to approve rates charged by

POLRs. Texas QFs argued that PURPA defines "State regulated electric utility" as "any electric utility with respect to which a State regulatory authority has ratemaking authority." Texas QFs further pointed to *FERC v. Mississippi* in arguing that this very broad definition was intended to encompass any electric utility for which a state regulatory authority exercises adjudicatory or ratemaking authority. Texas QFs argued that nothing in PURPA implies or suggests that "ratemaking authority" means "extensive ratemaking authority," "traditional ratemaking authority," "general authority to instigate rate-setting proceeding to revise the rates," or "traditional cost of service ratemaking." Texas QFs argued that if Congress had intended such general, comprehensive, cost of service ratemaking authority, it could have easily stated so.

Contrary to the utilities, Texas QFs further argued that the commission need not have state law authority to regulate PTB REPs and POLRs wholesale power purchases from QFs in order for it to be required to implement PURPA. Texas QFs and TIEC asserted that the obligation to implement PURPA comes from PURPA, even if the state Legislature has not conferred specific power to regulate the power purchases. Texas QFs indicated the lack of state authority conferred on the commission over wholesale QF power purchases from PTB REPs and POLRs is a non-issue. Notwithstanding, Texas QFs and TIEC argued that the commission has explicit and implicit state law authority under the mandate in PURA §35.061, which requires the commission to adopt and enforce rules to encourage the economical production of QF power.

Texas QFs further argued that, per *FERC v. Mississippi*, the commission has the obligation to implement PURPA if the commission has "state adjudicatory machinery" in place to enforce and entertain claims analogous to those granted by PURPA. Thus, if the commission has the power to adjudicate claims involving QFs and PTB REPs and POLRs, the commission must implement PURPA. Texas QFs further cited to provisions in PURPA in which procedural provisions exist that would provide the commission sufficient tools to implement PURPA consistent with the Court's instruction in *FERC v. Mississippi*. Given the adjudicative and procedural machinery together with the federal mandate to implement PURPA, the commission must enforce the FERC PURPA rules.

Finally, Texas QFs argued that implementation is not optional as Entergy REPs and TXU assert *FERC v. Mississippi* and *Printz v. United States*, 521 U.S. 898, 117 S.Ct. 2365 (1997) addressed PURPA, Titles I and III which pertain to permissive implementation of rate matters as opposed to Title II – the PURPA provision subject of this rulemaking – which addresses purchasing obligations. However, Texas QFs conceded that *FERC v. Mississippi* does not require a state commission to establish regulations. At a minimum, the state commission must only adjudicate and resolve disputes between electric utilities and QFs.

Citing to *FERC v. Mississippi* and *Printz*, Entergy REPs, AEPSC, and TXU argued in reply to Texas QFs that the federal government may not direct a state to carry out a federal program without the state's consent. AEPSC acknowledged that the federal government could require the observance of federal law in *adjudications*. AEPSC pointed out that the Court in *Printz* specifically stated that *FERC v.*

Mississippi would have been decided differently had it been based on *non*-adjudicative implementation (*i.e.*, rulemaking). Further, AEPSC asserted that such State claim adjudications must be analogous to the claims granted by PURPA or the PURPA claims adjudicated must be of the very type customarily engaged in by the state. The commission must have underlying subject matter jurisdiction to be allowed to conduct adjudications on PURPA issues (pricing, terms, and conditions of wholesale power transactions in a competitive market). Thus, the commission having "adjudicatory machinery" or procedural mechanisms in place is not sufficient to require the commission to adjudicate PURPA claims disputes between QFs and REPs because the commission does not have state law jurisdiction over price, terms, and conditions of wholesale power transactions. Similarly, Entergy REPs argued in its reply comments that state law jurisdiction to entertain claims analogous to those granted in PURPA is dubious.

Additionally, AEPSC concurred with RRI and TXU that if the commission finds that it has ratemaking authority over PTB REPs and POLRs, it should be limited to this rulemaking proceeding.

The commission agrees with Texas QFs and TIEC and finds that it has ratemaking authority, through PURA Chapter 39, over PTB REPs and POLRs and a federal mandate to implement PURPA QF power purchase obligations. Although, the ratemaking powers conferred upon the commission in PURA Chapter 39 may not be "plenary" or completely resemble "traditional" cost of service ratemaking authority over vertically integrated utilities, the commission agrees with Texas QFs that PURPA does not provide any indication of the scope of "ratemaking authority." The commission disagrees with RRI that the proposed rule broadens the commission's limited authority over POLRs and PTB REPs, for PURPA purposes, to general ratemaking authority. Further, the commission finds that it can institute regulations that implement power purchase obligations upon PTB REPs and POLRs without affecting REPs' PURPA obligations separate from commission imposed obligations.

The commission agrees with Texas QFs and TIEC that, together with the federal PURPA mandate and state ratemaking jurisdiction under PURA Chapter 39, the commission has underlying state authority to direct how PTB REPs and POLRs will purchase QF power through PURA §35.061 which mandates the commission to adopt and enforce rules to encourage the economical production of QF power. The commission further acknowledges that, pursuant to the FERC's May 17, 2001 "Order Granting Declaratory Order and Denying Waiver of Regulations Implementing PURPA" in FERC Docket Nos. EL01-49-000 and EL01-60-000, all unbundled REPs, transmission and distribution companies, and power generation companies are federally mandated under PURPA to take puts of energy from QFs. The commission does not agree with the parties who argue that the Legislature altered, through SB7, the commission's authority under PURA §35.061, with regards to REPs. Rather, the commission believes that the Legislature did not intend any alteration of the commission's powers to regulate QF power sale, including to REPs, by the passage of the PURA Chapter 39 provisions in SB 7. Thus, the commission finds that through the federal PURPA mandate to implement QF power purchase obligations, state ratemaking jurisdiction under PURA Chapter 39, the state mandate under PURA §35.061 to adopt and enforce rules to encourage economical production of QF power, and an endeavor to regulate consistent with federal law, the commission has jurisdiction to implement PURPA through this rulemaking. To the extent that TXU and AEPSC have concerns regarding the expansion of the commission's ratemaking jurisdiction beyond the authority conferred by PURA, the commission finds that its retail ratemaking jurisdiction in areas open to competition is currently limited to the price to beat charged by the affiliated REP and POLR rates .

Expanding the jurisdictional arguments, Texas QFs noted that the commission has ratemaking jurisdiction over the transmission and distribution utilities (TDUs) which, under federal law, retain the obligation to purchase PURPA energy. Similarly, OPUC noted that if commission staff's interpretation of its jurisdiction is correct – that affiliated REPs (AREPs) and POLR's must accept QF puts because they are subject to rate making procedures – then this jurisdiction should extend to affiliated power generation companies (APGCs). OPUC argued that the APGC should also be forced to accept QF puts, as it is also subject to the rate making process via the true-up proceeding. In response, TXU contended that the commission does not have jurisdiction to implement PURPA for TDUs or APGCs. TXU argued that while the true-up proceeding is an act of ratemaking authority over TDUs, the TDUs do not sell electric energy, and PURPA obligations only apply to entities that sell electric energy. TXU further explained that in the true-up preceding the ratemaking authority is over TDUs and not APGCs, as the commission only gathers information from the APGCs to adjust the rates of their affiliated TDUs. Therefore, TXU noted that APGCs must self-implement their PURPA obligations. AEPSC also disagreed with OPUC's conclusion that APGCs fell under commission jurisdiction. AEPSC noted that although APGC is subject to a true-up proceeding, the commission has no authority to change its rates.

The commission agrees with TXU and declines to impose PURPA put requirements on TDUs or APGCs. The commission agrees with TXU that the commission does not have jurisdiction to implement PURPA power purchases over APGCs. The commission continues to have jurisdiction over TDUs; however, the commission recognizes that PURPA power will not be put to TDUs.

First Choice objected to the possibility of being forced to accept supplies from non-competitive suppliers. Its complaint is based upon the fact that First Choice has a contract with its wholesale supplier that requires it to purchase most of its power from that supplier. It claims that other PTB REPs with generation affiliates can accommodate the requirement to purchase power from QFs, but that it cannot due to the lack of such an affiliate. First Choice cites proposed subsection (f)(5) as applying to utilities that do not own generation. TXU disagreed with First Choice's request for an exception for accepting and pricing power from QFs. TXU noted in their reply comments that under FERC case law, "PURPA electric utilities that are customers to full-requirements supply contracts are still obligated to purchase QF power, however their avoided costs are set at the avoided costs of their full-requirements suppliers." AEPSC agreed with First Choice that it is in a difficult position, but stated that First Choice's problem is not unique and that no AEPSC REP owns any generation either. AEPSC requested that First Choice not receive different treatment with regard to its PURPA obligations.

The commission finds that First Choice is in a difficult position, but agrees with AEPSC and TXU that it is not unique, and therefore, should not receive different treatment with regard to its PURPA obligation.

First Choice must comply with PURPA, as it meets the PURPA definition of "electric utility." Accordingly, the commission declines to grant First Choice's exception.

General comments on market based price and avoided cost

RRI, AEPSC, and TXU argued that if the commission is found to have jurisdiction, then a market-based pricing mechanism should be used. RRI argued that if the commission determines that a rule must be adopted, the proposed rule's definition of market price must be maintained in order to avoid conflicts with the PTB and to ensure that potential POLRs will bid to be POLRs. AEPSC stated that FERC has encouraged the commission to use market-based pricing.

Texas QFs argued that adopting the "market price" as proposed will give PTB REPs and POLRs free rein to implement rates which are nontransparent, calculated only after-the-fact, and highly subject to manipulation and gaming. However, AEPSC disagreed with the Texas QFs' assertion that self-implemented QF rates are subject to gaming, pointing out that such rates are heavily dependent on the market clearing price of energy (MCPE), which is independently determined by ERCOT. Entergy REPs, in initial and reply comments, commented that a specific definition for market price should not be included in the rule, and advocated in favor of restoring a general market standard that can be developed through self-implementation.

Texas QFs argued that as proposed, QFs will never know what the purchase price will be at the time of commitment. The Texas QFs argued that the proposed amendments fail to establish either a methodology for determining avoided costs, or an avoided cost rate, for purchases from QFs. Texas QFs contended that the payment methodology based on the market price of energy purchases proposed in subsection (i)(4), with the definition of market price in subsection (c)(8), is completely circular and fails to implement avoided cost pricing rates for purchases of QF energy. Texas QFs argued that the market is left without a transparent pricing mechanism for non-firm energy, depriving QFs of not only a reasonable estimate of the price they may be paid for their non-firm energy at the time they must schedule or deliver it, but also of the knowledge that payment will be received. Texas QFs commented that this fails to comply with the PURPA mandate to set avoided cost rates. Texas QFs argued that the definition of "market price" is too vague and should reflect the purchasing utility's highest (and least efficient) running costs or purchased power cost, i.e., the utilities "incremental costs" as required by PURPA. Finally, Texas QFs argued that granting the PTB REPs and POLRs the discretion to determine their own avoided costs constitutes an abdication by the commission of its PURPA responsibility to set avoided cost rates.

Texas QFs proposed the following definition of market price: "Market price for each 15-minute settlement interval is determined by multiplying the Heat Rate of the Marginal Unit times a fuel index. The Marginal Unit will be determined pursuant to the 'unit commitment' plan of the Qualified Scheduling Entity (QSE) for the PTB REP or POLR as submitted in that QSE's Day Ahead ERCOT schedule and Resource Plan. The Heat Rate will be based upon those determined to be appropriate proxies for the

Marginal Unit as adopted for utilities' generating fleets in Section 25.381 of this Title. The fuel index will be an index appropriate for the type of generating unit on the margin (i.e. for gas units, it will be the Daily Gas Price)." Texas QFs reasoned that since there is no established day-ahead or real-time market (e.g. a "power exchange") in ERCOT, their proposal is based upon the heat rates and fuel prices of the capacity auction products contained in §25.381, relating to Capacity Auctions, as well as the day-ahead ERCOT schedule and Resource Plan of the PTB REP's or POLR's QSE. Texas QFs stated that their proposal, consistent with the FERC's invitation to determine avoided costs in a market-oriented manner, utilizes the PTB REP's or POLR's QSE's Day-Ahead unit commitment plan to determine the unit on the margin – after the QSE has taken into account any possible day-ahead market opportunities. The units committed to run by the QSE should reflect a market price, because the QSE would not commit a unit to run if its incremental cost was not at or below market. Texas QFs noted that this still was not a published market price, but argued that it reflects what the QSE reasonably expects the energy market to be, and is therefore not subject to the same abuses and manipulations as a self-determined or MCPE market price. Once the unit on the margin is identified, Texas QFs argued, the proposal then utilizes capacity auction products as commission-approved market proxies for the marginal units determined by the "unit commitment" of the PTB REP's or POLR's QSE.

Texas QFs commented that their proposal offers the following benefits: it relies on the actual "unit commitment" schedule of the AREP's or POLR's QSE, so by definition it is a "market based" rate; it utilizes heat rates and fuel price indices already approved by the commission in the capacity auction rule; and because it is reasonable, there is no need for AREPs to file confidential, competitively-sensitive power purchase agreements with the commission to verify that they are correctly calculating their avoided costs.

TXU offered a list of comments regarding TIEC and the Texas QFs' proposed avoided cost methodologies. First, TXU opposed TIEC and the Texas QFs' proposed definition of "market price" indicating that it is irrelevant to entities that do not own generation and could require PTB REPs and POLRs to pay more than their individual avoided cost for QF power. TXU argued that PTB REPs and POLRs must purchase all of their power supplies so their avoided cost should be what they would have paid to purchase power if not for the purchase of QF power. TXU further commented that while fuel prices and heat rates may indirectly affect the price of power purchases by PTB REPs and POLRs, these factors do not necessarily account for all the costs that a particular PTB REP or POLR avoids with the purchase of QF power. Second, TXU commented that PTB REPs and POLRs will not always receive power from their APGCs and that pricing arrangements with suppliers will not always be based on incremental generating costs of their suppliers. Third, TXU argued that the methodology proposed by TIEC and Texas QFs would require PTB REPs and POLRs to pay more than their avoided costs for QF power by imposing firm pricing for non-firm products. TXU was also concerned that TIEC's and Texas QFs' methodology would create an arbitrage opportunity for QFs by establishing day-ahead firm avoided cost prices. Fourth, TXU contended that TIEC and Texas QFs' proposal to use the "marginal unit" in a PTB REP's or POLR's QSE-unit-dispatch to measure the REP's avoided cost is illogical for two reasons: (1) a PTB REP's or POLR's QSE may or may not represent generating units for dispatch; and (2) a QSE may represent multiple market participants that affect its dispatch decisions causing the QSE's marginal unit to be unrelated to the avoided cost of the PTB REP or POLR. Fifth, TXU addressed Texas QFs' initial comments that PTB REPs and POLRs self-implemented avoided cost will be after-the-fact. TXU explained that PURPA rules do not require that PURPA electric utilities calculate or state their avoided costs before-the-fact. The PURPA rules require that electric utilities make available the data needed to estimate avoided costs. TXU also stated that no QFs have approached them to acquire any of the above-mentioned avoided cost data. Finally, TXU argued that TIEC and Texas QFs are seeking to apply unrelated proxy prices through the use of heat rates and fuel rates used in the capacity auction to determine avoided costs. TXU deemed that the proxies were created for the purpose of the capacity auction and therefore do not represent the actual operation of any particular utility or generating unit. TXU was concerned that by using the proxy prices as a measure of avoided cost, there is potential for PTB REPs and POLRs to pay more than their avoided cost for QF power which is in violation of PURPA and FERC rules.

RRI and AEPSC also disagreed and took issue with the Texas QFs definition of "marginal unit" which is based on the "unit commitment" plan of the QSE for the PTB REP or POLR. RRI asserted that it would require creation of a new QSE for the REP to separately schedule for PTB and/or POLR obligations, which is not required by PURA and which would impose additional costs on the REPs and their PTB and/or POLR customers. RRI further pointed out that the QFs do not offer any feasible method for determining the marginal unit from the unit commitment plan, which creates insurmountable problems. AEPSC argued that QSE's are not subject to the commission's jurisdiction and other market participants' QSEs are not required to disclose such information. AEPSC argued that disclosing its marginal heat rates will put a PGC at a competitive disadvantage, and a QSE may have more than one marginal unit.

RRI also took issue with the Texas QFs assertion that "the QSE would not commit a unit if its incremental cost was not at or below market." To the contrary, RRI stated a QSE may commit a unit even if its incremental cost is above market in order to have the units available to meet peak obligations, to participate in the ancillary service markets when the profit more than offsets the loss on energy sales, and the units may be forced by ERCOT to run for reactive power. Thus, RRI asserted that these given circumstances should not be considered "unit on the margin" for determining price that should be paid for QF energy deliveries. Ultimately, RRI argued that the Texas QFs proposal is unworkable, creates gaming opportunities and will result in higher costs to customers.

Additionally, RRI also pointed out that responsibility transfers are further complicated because QSEs do not have the capacity to dynamically adjust resources in its QSE to accommodate the PURPA put. Without the supply resources in its supply portfolio to directly control, the QSE used by the PTB REP and POLR would be exposed to the balancing energy market for QF deliveries. Under such scenario, the PTB REP or POLR would not be purchasing from the QF but rather would have purchased power that is sold to ERCOT via the balancing energy market. Thus, the definition of market price contained within the proposed rule would not correctly apply because the PTB REP or POLR would not have foregone power purchases due to the purchase from the QF. RRI asserted that only the QSEs are authorized under the ERCOT Protocols to schedule energy, so the PTB REPs and POLRs therefore will not be able to implement responsibility transfers on their own. Texas QFs agreed in reply comments, but stated it should be a simple matter for the PTB REPs and POLRs to require such capability in their contracts with their QSEs.

In reply comments, RRI generally agreed with OPUC that the Texas QFs' approach "encourages market manipulation and gaming which distort the market and raise power costs. The effect of such tariffs would be to develop a floor price for QF power, since the QF producer would always be free to sell at market rates when it is more beneficial to do so."

AEPSC commented that "market price" should be defined by the MCPE as determined by ERCOT. AEPSC stated that the rule's definition of "market price" is too vague and will result in commission imposed prices, rather than market-based prices. AEPSC argued that the proposed definition depends on which purchases were forgone by the REP and will lead to complaints by the QF. Texas QFs' objected to this proposal, noting that FERC found that ERCOT energy imbalance price neither constitutes a market price nor is it an adequate substitute for a QFs right under PURPA to sell to a purchasing utility at its avoided cost rates. Texas QFs commented on the FERC's statement that ERCOT ancillary purchases occur only after utilities have fully bilaterally arranged for and dispatched their own generation to their affiliated REPs. Texas QFs argued that the ERCOT imbalance service effectively is a "last stop" reliability service that is in no way related to a utility's incremental costs of generation. Texas QFs pointed out that the ERCOT imbalance market is "far smaller" than the short-term market as a whole. Texas QFs argued that due to its small size, lack of liquidity, and the fact that no market participant can purchase energy from the imbalance bid stack, it is not a market at all. Texas QFs argued that the price in that market has often been negative or zero.

AEPSC argued in its reply comments that FERC did not prohibit the use of MCPE for pricing purposes as the Texas QFs suggested. Rather, AEPSC argued that FERC did not address the issue of MCPE and simply ruled that the opportunity to sell ancillary services to ERCOT does not fulfill PURPA obligations. AEPSC further contended that the use of MCPE is a superior pricing method than that suggested by the Texas QFs and TIEC. AEPSC stated that formulaic pricing is inconsistent with market-based pricing and will hinder the development of a fair and competitive energy market. AEPSC also argued that the capacity auction heat rate is inaccurate, and therefore, inferior to MCPE. AEPSC also responded to the Texas QFs' statement that a negative or zero price for balancing energy indicates that the market is not working properly. AEPSC directly disagreed and stated that such prices indicate that the marginal benefit of additional power is negative. Therefore, a negative price for balancing energy is sometimes appropriate. AEPSC also noted that balancing energy prices are negative a small percentage of time. AEPSC countered the Texas QFs' argument that pricing after the fact is unacceptable by stating that it is necessitated by logistical constraints. AEPSC also stated that QFs could enter into bilateral contracts with purchasers if they demanded increased price certainty.

RRI also asserted that a PURPA defined electric utility operating in the competitive market place should not be obligated to pay more than market price, nor should it be obligated to take more than it is able to accept consistent with its other obligations. RRI stated that residual QF energy could be put to ERCOT in real-time which would exercise decremental balancing energy bids to accommodate such energy. Per RRI, the avoided cost for such placement would be the market-clearing price for balancing energy less any imbalance penalties. Alternatively, RRI argued that residual energy put to the PURPA defined electric utility would appear as resource imbalance and receive the market-clearing price less any imbalance penalties.

First Choice proposed that the price should be the balancing energy market-clearing price for the ERCOT congestion zone in which the power is produced if it is required to take power from other QF suppliers. First Choice argued that any market price definition that comes out of this rulemaking needs to recognize this congestion zone distinction.

TXU proposed changing the defined term for subsection (c)(8) from "market price" to "power purchase avoided cost" to prevent confusion as the term market price has different meanings to different parties. AEPSC disagreed with TXU's suggestion, arguing that "market price" was more in the spirit of the FERC ruling and SB 7. On the other hand, Entergy REPs agreed with TXU's position that the proposed market price definition in the proposed rule does not actually define a market price, but instead refers to a "purchased power avoided cost." Entergy REPs did not believe that "purchased power avoided cost" would be a desirable formula for determining the price to be paid for as-available QF energy. Entergy REPs indicated that this market priced definition will often refer to REPs' costs under bilateral contracts, rather than market price. Given that the bilateral contract price may be above or below market at times, QFs may take advantage of making their as-available power sales at a price that will create arbitrage opportunities and ultimately distort the market and impose additional costs on the purchasing REP. TXU likewise commented that a PTB REP's or POLR's avoided cost for QF power could be based on a bilateral contract and not necessarily the market price for energy in a certain market. Entergy REPs recommended, if a definition is included, that the commission adhere to market standards that will treat all market participants equally and allow recovery of all costs associated with QF transactions. Entergy REPs further contended that the problems created by the use of the "purchased power avoided cost" formula will also be avoided through adherence of market price standards. TXU supported the proposed definition which utilizes individualized determination of avoided costs.

TXU further opposed Entergy REPs' proposal to defer the creation of an avoided cost methodology to compliance filings. TXU responded to Entergy REPs' concerns of arbitrage opportunities resulting from contract prices for power prices being revealed by explaining that most power purchase contracts are not fixed price contracts. TXU further explained that most power purchase contracts have prices determined by indices or costs that create uncertainty in the final dollar amount paid upon settlement which also creates uncertainty to prevent arbitrage opportunities.

The commission finds that it is appropriate to use a market-based pricing method for calculating avoided cost as opposed to a pricing method that is formulaic in determining avoided cost. Specifically, the commission finds that the closest approximation of a market price for avoided cost is the market-clearing balancing energy price for the ERCOT congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties, and fees typically applied to power generators. The commission finds that this price most closely reflects avoided costs for the marginal unit of energy. To the extent that it is impossible for a REP to predict its load with 100% accuracy, each REP will have to either buy or sell a small amount of balancing energy. To the extent that QF energy displaces any of the REP's demand for balancing energy, the balancing energy price is the REP's avoided cost. Likewise, when a REP over-schedules with ERCOT, it receives the balancing energy price for its excess energy. This is true regardless of whether or not the REP would have overscheduled had it not fulfilled its PURPA obligations. Therefore, the commission finds that the balancing energy price is the most appropriate estimate of avoided cost.

The commission further finds that the balancing energy price should be used to determine avoided cost because it reduces the ability for any interested party to conduct in gaming. This is precisely because prices are not revealed until after the market has cleared. If the price was known *ex ante*, then it could act as either a price floor for QFs or a price ceiling for REPs. Either situation would encourage market manipulation. Furthermore, while PURPA mandates that a REP must accept energy from a QF, PURPA does not mandate that the QF must put to a particular REP. If the QF seeks a more certain price, the commission notes that it is free to seek other markets for its energy, such as entering into long-term bilateral contracts. The commission finds that it is also appropriate to explicitly permit a QF to agree to commit, on a day-ahead basis, to deliver firm power for the next day to a PTB REP. If a QF commits to deliver firm power on a day-ahead basis, the commission finds that rates for purchases of this power shall be based on prices for the day that the power was actually delivered as reported or published in an independent third party index or survey of trades of commonly traded power products in ERCOT, provided that the index or survey is ERCOT-specific and is based upon enough transactions to represent a liquid market, and the commitment to deliver shall correspond with the relevant hours of delivery of those products. The commission finds that this additional option is appropriate because it will provide another option for QFs while preventing the arbitrage opportunities identified by several of the commenters. Subsection (g)(3) has been added to prescribe the rates for purchases from a QF that has committed to delivering firm power on a day-ahead basis.

To the extent that the price of balancing energy is zero or negative, this does not negate a REP's PURPA obligations. Rather, a non-positive price indicates that the cost that the additional energy creates exceeds its benefits. The fact that the price may be zero or negative reflects the risk inherent in the current market structure and can be appropriate for non-firm energy. Finally, the use of such a price is revenue neutral to the REP. Thus, there should be no increase in costs to pass along to PTB REP or POLR customers.

The commission understands the argument made by the QFs and TIEC that granting them the opportunity to sell ancillary services, such as balancing energy, does not fulfill PURPA obligations. However, the commission finds that said parties are misinterpreting the decision made by FERC in its May 17, 2001 "Order Granting Declaratory Order and Denying Waiver of Regulations Implementing PURPA" in FERC Docket Nos. EL01-49-000 and EL01-60-000. The commission understands the FERC ruling to say that the opportunity to bid into the Independent System Operator run markets does not fulfill PURPA obligations. However, that is not the solution that the commission adopts. Rather, the commission finds that the PTB REPs and POLRs have an absolute obligation under PURPA to accept energy on behalf of the QF. The commission also finds that the balancing energy price is the appropriate determination of avoided cost and should be used to determine proper compensation for all energy supplied to the REP by the QF, absent any other private agreement reached by said parties.

Another issue of debate among the parties was the issue of requiring REPs to provide certain cost data. Texas QFs argued in the alternative, that if the circular definition of "market price" is adopted, the PTB REPs and POLRs should be required to provide their avoided cost data to the QFs, as set forth in 18 C.F.R. §292.302. In addition, the PTB REPs must be required to file all agreements under which they purchase energy, and QFs must be allowed to review such agreements to ensure that the prices they are paid truly reflect the PTB REPs avoided cost of energy. RRI and AEPSC opposed the Texas QFs proposal that AREPs be required to file and make public, pursuant to 18 C.F.R. §292.302, certain detailed cost data. RRI asserted that after restructuring such requirement upon AREPs made little practical sense. RRI reasoned that prior to restructuring, a single entity controlled a generation and distribution "system" and that there were no competitive concerns. Post restructuring, AREPs no longer have such a system as contemplated by 18 C.F.R. §292.302, and thus is inapplicable. RRI surmised that AREPs likely now rely on competitive information in order to compete in the market, and an unequal filing requirement of such information will provide a competitive advantage for QFs to the detriment of AREPs. AEPSC argued that disclosure of such information would put said AREPs at a comparative disadvantage and stunt the growth of a competitive market. AEPSC also mentioned that the commission does not have the authority to make PTB REPs and POLRs disclose such information.

The commission finds that disclosure of REPs cost data is not necessary in view of the market-based pricing method adopted by the commission. Therefore, the commission declines to adopt Texas QFs proposal and does not require the production of cost data for the PTB REPs and POLRs.

Concern over POLR rates

Additionally, RRI, TXU, AEPSC, and OPUC commented that applying the rule to POLRs may raise additional concerns. RRI argued that the proposed rule would be particularly problematic for POLR service, to the point that it would act as a disincentive for REPs to bid to become POLRs because they would be subject to additional commission regulations beyond the POLR regulations. TXU also suggested that by classifying POLRs as state-regulated PURPA electric utilities that are subject to commission ratemaking authority, the commission will discourage REPs from applying for POLR status. TXU argued that while REPs, as electric selling entities, have the federal obligation to purchase QF power, REPs could be discouraged knowing that by achieving POLR status they give up their right to self-implement PURPA. AEPSC agreed with TXU and RRI that the proposed amendments will discourage REPs from attempting to become POLRs. AEPSC argued that the amendments would result in the QF favoring puts to the POLR REP, increase the uncertainty associated with providing such service, and lead to an increase in POLR rates.

OPUC made the point that POLR rates are already high because it is difficult for the POLR to predict its load, and therefore use hedging contracts to control the price of their inputs. Forcing the POLR to accept stochastic QF puts will only exacerbate this effect. OPUC stated that accepting QF power may result in an inefficient allocation of resources that could cause the costs associated with providing PTB and POLR services to increase. OPUC pleaded that the AREP not be allowed to use such an increase in costs to justify an increase in rates for PTB and POLR customers. OPUC further argued that prices for QF power should be determined through market-based methods, rather than through formulaic tariffs that set avoided cost. Using tariffs will have the effect of creating a price floor, and hence, encourage gaming. OPUC was concerned that the proposed rule does not mandate a market-based approach, but rather adopts it if and only if the QF agrees to such a method. In response to OPUC, TXU asserted that an appropriate avoided cost determination would nullify OPUC's concern that imposing the PURPA obligations on the PTB REPs and POLRs will drive up retail rates for residential and small commercial customers. TXU stated that an appropriate avoided cost determination will have no effect on PTB REPs' and POLRs' purchase power costs as the idea is for the PURPA electric utility to pay no more for QF power than it would have paid to otherwise obtain power.

The commission agrees with the concerns raised by OPUC, RRI, TXU, and AEPSC regarding the potential disincentives that this rule may have on REPs seeking to become POLRs. However, the commission finds that PURPA requires state commissions to implement PURPA for all entities over which the state commission has ratemaking authority, which this commission clearly does have with respect to POLRs. As a result, the commission declines to make this rule applicable to POLRs, and instead will address PURPA implementation for the POLR REPs on a case-by-case basis.

Comments on specific rule sections

§25.242(b) – Application

Brazos offered clarifying language to dismiss any misconceptions that even as a POLR, this section would not be applicable to an electric cooperative. Brazos explained that in PURA §41.053 an electric cooperative may designate itself or another entity to be the POLR within the electric cooperative's certificated service area. If the electric cooperative acts as the POLR, the electric cooperative must offer the customer the standard retail service package as approved by the electric cooperative's board of directors. Brazos proposed language to clarify the idea that the commission has no jurisdiction over the rates of electric cooperatives or municipalities. AEPSC noted that the comments made by Brazos that the proposed rule does not apply to cooperatives, even if they are acting as POLR, underscored its jurisdictional concerns.

For the reasons discussed above in *Concern over POLR rates*, the commission declines to implement PURPA over POLRs through this rulemaking. Thus, the commission does not believe it necessary to adopt Brazos' proposed clarification language. Notwithstanding, PURA Chapter 41 has altered the commission's jurisdiction over electric cooperatives much more comprehensively than that over REPs.

The commission asserts jurisdiction over PTB REPs and POLRs in part based on the ratemaking authority it possesses through PURA Chapter 39. PURA Chapter 41 specifically places ratemaking authority over electric cooperatives in the hands of the cooperative's board of directors. The electric cooperative board of directors' ratemaking authority extends to electric cooperative POLRs pursuant to PURA §41.053(d).

§25.242(c) –Definitions

TXU offered amendments to make the definition of "cost of decremental energy" in subsection (c)(3) consistent with the use of the term in proposed subsection (i)(3). AEPSC commented that subsection (c)(3) should be clarified and specifically reference electric utilities, not simply utilities.

The commission declines to adopt the revisions recommended by TXU and AEPSC. The commission finds that the term decremental energy only exists in subsection (i)(3) which applies to electric utilities as defined in subsection (c)(4).

First Choice expressed concern about the usage of subsections (c)(1) and (c)(8) under the amended rule.

The commission acknowledges First Choice's concerns regarding amendments made to (c)(1) addressing the definition of "avoided costs" and (c)(8) adding a definition of "market price." However, the commission adopts the definitions changes made based on its reasoning expressed in this preamble.

§25.242(f) - PTB REP and electric utility obligations

§25.242(f)(1) – Obligation to purchase from qualifying facilities

AEPSC commented that subsection (f)(1)(A)(i) and (ii) should be deleted. They are confusing and not applicable under the new ERCOT market structure.

The commission finds subsection (f)(1)(A)(i) and (ii) still applies to electric utilities as defined in subsection (c)(4). In the case of PTB REPs, it reiterates the point that delivery from the QF may be directly connected via the affiliated TDU to the facility or via transmission to PTB REPs located in other TDU service areas.

AEPSC commented that subsection (f)(1)(B) should be amended to specifically address the 90 day notice requirement for PTB REPs and POLRs.

The commission notes that many of the provisions in (f)(1)(B) relate to interconnection of the QF to the transmission and/or distribution grid and therefore, are not applicable to PTB REPs and POLRs.

Additionally, for the reasons discussed above in *Concern over POLR rates*, the commission declines to implement PURPA over POLRs through this rulemaking. However, the commission agrees with AEPSC that similar timelines for finalizing agreements to purchase energy should be completed in a timely manner but does not agree that such agreements should take 90 days to reach given the prescriptive avoided cost methodology in this rule. The commission adds new subsection (f)(1)(C) to clarify this obligation.

§25.242(f)(2) Obligation to sell to qualifying facilities-

AEPSC commented that subsection (f)(2) should be changed to only apply to POLR REPs. AEPSC argued that the commission does not have the authority to order any REP to provide service to a non-PTB customer. Alternatively, AEPSC suggested that the phrase "market based rates" be changed to "mutually agreed upon rates" to circumvent this problem.

TXU opposed TIEC's proposal to require PTB REPs and POLRs to sell energy and capacity to QFs at the REPs avoided cost plus reasonable administrative expenses. TXU contended that PURPA rules require a PURPA electric utility to sell to QFs at rates that are nondiscriminatory. TXU further argued that there is no precedent to use avoided costs to determine rates for energy and capacity sold to QFs. First Choice expressed concern about the lack of a definition for "market based rates" in subsection (f)(2).

Entergy REPs generally agreed with proposed subsection (f)(2), which governs sales to QFs. However, Entergy REPs stated that this section fails to explicitly provide for recovery of incidental administrative, billing and metering costs from QFs, and expressed preference that such provision be explicitly inserted in the subsection (f)(2). Nonetheless, Entergy REPs believed that full cost recovery is implicit in the market standard contained in the proposed rule. Entergy REPs, in reply comments, disagreed with TIEC's proposed pricing mechanism that would price sales to QFs at avoided costs plus an allowance for administrative costs, stating that such mechanism would not recover demand-related charges that are often associated with sales to QFs.

The commission finds that its jurisdiction is limited to POLR and PTB REPs. For the reasons discussed above in *Concern over POLR rates*, the commission declines to implement PURPA over POLRs through this rulemaking. The commission finds that the avoided cost for PTB REPs is the MCPE for the ERCOT congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties, and fees typically applied to power generators. The commission finds, pursuant to PURPA, that QFs selling to non-POLR and non-PTB REPs should self-implement PURPA and set avoided cost at a mutually agreeable price and in a non-discriminatory manner. The commission also finds that it is not a commission requirement but a PURPA requirement that electric utilities sell standby, back up, and maintenance power to QFs at market rates. The commission further finds that this requirement has been harmonized by allowing these rates to be at the market value for these services.

§25.242(f)(4), Transmission to other electric utilities

AEPSC commented that subsection (f)(4) should be deleted because it is confusing and not applicable under the new ERCOT market structure.

The commission disagrees with AEPSC's comment that subsection 25.242(f)(4) should be deleted. QFs receiving or providing electricity from the grid will require transmission service. The obligations and rules of Subchapter I continue to govern transmission service irrespective of the new ERCOT market structure. The rules of Subchapter I were developed to support the new ERCOT market structure and the commission declines to delete this subsection.

§25.242(f)(5), PTB REP and POLR scheduling with qualifying facilities

TXU recommended deletion of proposed subsection (f)(5) as it regards the use of dynamic scheduling and responsibility transfers. TXU supported the initial comments of RRI and OPUC as well as echoed their comments that these forms of scheduling are not yet part of the ERCOT protocols. Further, TXU deemed that dynamic scheduling and responsibility transfers are not needed for QF puts and that static scheduling will accomplish QF puts leaving QFs exposed to the same financial imbalance concerns that apply to all PGCs in the new market. TXU also urged that the commission allow QFs and purchasing utilities to continue to work together to determine appropriate means for the technical transactions as it done in the past and not to use the rule to fix technical specifications that will likely change and evolve over time. Likewise, AEPSC urged the commission to reject Dynamic Resource Scheduling (DRS) because many different generators serve unpredictable loads and requiring DRS would give QFs an unfair advantage over other generators. AEPSC further contended that DRS will result in increased costs for PTB REPs and POLRs as certainty commands a price premium and that requiring dynamic scheduling would discourage efficient production of electricity. Furthermore, AEPSC argued it would require the REP to seek additional flexibility from its other suppliers. In this vein, AEPSC argued that subsection (f)(5), which requires PTB and POLR REPs to offer DRS, should be deleted.

Likewise, OPUC asked that the commission delete subsection (f)(5), requiring the availability of DRS. Although this service has been traditionally provided by integrated utilities, the new market structure does not support this because the generation and control areas no longer operate in a bundled manner.

RRI also argued that DRS is an optional service and is not necessary for QFs to deliver PURPA put energy nor are they required by ERCOT, although efforts are underway at ERCOT to define how such scheduling might work. RRI recommended revisions to subsection (f)(5) to indicate the service is optional. RRI asserted that static scheduling is adequate and will be used by other PGCs on a regular basis. RRI argued that QFs should be subject to the same balancing energy market exposure taken by other PGCs in the ERCOT market, if scheduling is not met. RRI argued that QFs would be advantaged and have arbitrage opportunities should they be allowed to avoid such exposure. RRI also suggested that the proposed rule be clarified to indicate that responsibility transfers can only be undertaken by

QSEs on behalf of REPs and QFs under the ERCOT Protocols, and that the ERCOT Protocols allow QSEs to offer responsibility transfers at their option under mutually agreeable contract terms.

Texas QFs and TIEC argued that it is imperative that DRS and/or responsibility transfers be utilized to accommodate PURPA energy, due to the intermittent, variable, non-firm and uncontrollable nature of the energy produced by QFs in excess of the needs of their steam hosts. TIEC also argued that the commission should require, through the rulemaking, that contracts between entities obligated to purchase PURPA power and QSEs make DRS available as quickly as possible if it not already available without "tying" such other services that a QF might be required to purchase.

The commission agrees with the Texas QFs and TIEC about DRS to the extent that it is desirable to better accommodate the fluctuating nature of their production. It does not agree with the recommendations that subsection (f)(5) be deleted. DRS should remain available as an option subject to the ability of the QF and its QSE to meet ERCOT's protocol requirements. The commission disagrees with the assertions that DRS would give the QFs an unfair competitive advantage because DRS is available to any energy supplier/QSE willing to utilize it.

§25.242(g) - Rates for purchases from a qualifying facility

§25.242(g)(2) – market based rates

OPUC stated that the term "just and reasonable operating expenses" is unclear and asked that the last sentence of subsection (g)(2) be deleted. OPUC claimed that this sentence could conflict with the PTB rule and create confusion. TXU, however, opposed OPUC's recommendation to delete the "just and reasonable operating expenses" provision from this subsection because it would be unfair not to allow PTB REPs and POLRs to recover costs from their customers.

AEPSC argued subsection (g)(2) should be deleted because the method of calculating avoided cost has not been fully determined and could result in the disclosure of a REP's cost information, putting it at a competitive disadvantage. AEPSC also commented that subsection (g)(2) contains a typographical error that should be corrected.

TXU suggested amending the second to last sentence of proposed subsection (g)(2) to create consistency between the subsection and PURPA rules at 18 C.F.R. §292.304(5).

TIEC supports the language proposed by Texas QFs as a modification of the definition of market price with the provision that if there is so much PURPA power available that more than one unit (or more than one type of unit) is avoided, then the heat rate and fuel index should be the average of the stack of all units avoided.

For the reasons discussed above in *Concern over POLR rates*, the commission declines to implement PURPA over POLRs through this rulemaking. The commission finds that this section relates to longer term purchases of energy and capacity and as such, in the context of PTB REPs should be fully negotiated between buyers and sellers in the competitive wholesale market. Alternatively, QFs may sell energy on a nonfirm, as available basis, and the commission finds that the MCPE is the appropriate estimate of avoided cost as defined in subsection (i)(4). Additionally, the term "just and reasonable operating expenses" does not apply in the context of a PTB REP as all of its purchases, including those from QFs, will be done at market based rates. Subsection (g)(2) has been modified to clarify that the term "utility" refers to still bundled electric utilities.

§25.242(i) – Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility

AEPSC commented that subsection (i) should be clarified in the following manner: Paragraphs (1) and (3) apply to electric utilities and paragraphs (2) and (4) apply to PTB and POLR REPs. AEPSC sought clarification whether PTB REPs and POLRs must file actual tariffs or simply a description of the methodology that will be used to determine rates and whether PTB REPs and POLRs have the authority to choose which method will be used when either the QF agrees to the method or when the QF chooses the method.

§25.242(i)(2)

TXU proposes amending the term "market price" to read "power purchase avoided cost" to be consistent with TXU's proposal for change in proposed subsection (c)(8). AEPSC commented that subsection (i)(2) should be clarified that the period of sale is negotiated, as this section deals with average costs.

Entergy REPs, in reply comments, disagreed with TXU's suggestion that proposed subsection (i)(2) be revised to refer to average "purchased power avoided costs" rather than average market price. Entergy REPs reason, as with its general discussion concerning avoided costs determination, is that QFs will benefit from arbitrage opportunities that would ultimately distort market prices with added costs to REPs. The Entergy REPs also recommended deletion of any reference to "average market price" or TXU's suggested "purchased power avoided cost" because parties should be free to enter into contractual arrangements based on mutually agreeable terms and conditions.

For the reasons discussed above in *Concern over POLR rates*, the commission declines to implement PURPA over POLRs through this rulemaking. Concerning PTB REPs, the commission agrees with the concerns raised and has made corresponding revisions to the language in subsection (i)(2) and (i)(4) to address these concerns. Particularly, the commission has now revised subsection (i)(2) to specifically address the manner in which PTB REPs and QFs can mutually agree to the terms of rates for energy sales to QFs that are different than the market price as defined in subsection (c)(8). Nevertheless, the commission believes what the rate is called is irrelevant to the issue to the extent that both parties in question agree on the price for QF energy.

§25.242(i)(4)

OPUC recommended that subsection (i)(4) be amended such that "shall" replaces "may," and that the phrase "at the option of the qualifying facility" be deleted. TXU opposed OPUC's recommendation, arguing that it would be unfair not to allow PTB REPs and POLRs to recover costs from their customers.

The commission disagrees with OPUC's recommendation. However, in light of the above decision to revise subsection (i)(2) with regards to PTB REPs and QFs reaching mutually agreeable terms for nonfirm sales to QFs, the commission has made corresponding changes to subsection (i)(4). The commission revises subsection (i)(4) to allow rates for purchases of nonfirm power to be based on the market price of energy (as defined in (c)(8) as MCPE) at the time of the sale to the QF, unless alternative arrangements have been made pursuant to subsection (i)(2).

§25.242(i)(5)

Texas QFs commented that they object to subsection (i)(5) which states that PTB REPS and POLRs must file with the commission a description of the methodology that will be used in calculating these rates for purchase, to the extent that it does not explicitly require commission approval for the methodology that will be used to calculate the individual utilities' avoided costs. Texas QFs stated that they want an opportunity for a contested case proceeding with commission approval of the ultimate methodology.

The commission deletes subsection (i)(5) given that it has adopted the MCPE as market prices. Because, through the adoption of the MCPE no methodology will need to be established, it is unnecessary for PTB REPs to make filings with the commission.

§25.242(j), Periods during which purchases not required

§25.242(j)(1)

TXU offered amended language throughout the subsection to carry the idea that in certain circumstances, electric utilities, PTB REPs and POLRs are permitted to decline to purchase QF power. TXU added that resource ramp limitations are not the only operational circumstances that could cause electric utilities, PTB REPs and POLRs to be in a position to pay more than their avoided costs for QF power.

AEPSC argued against subsection (j)(1), stating that the ability of a PTB REP or POLR to cease delivery because of operation concerns conflicts with the ability for the QF to obtain dynamic scheduling. There is no opportunity to provide notice under dynamic scheduling. AEPSC further argued that in addition to being an operational limitation, that ramp rate limitations may also be contractual limitations that a REP may have with its supplier. AEPSC stated that the commission should clarify that "utility" should refer to PTB REPs and POLRs and that the last sentence of the section does not clearly state the PTB REP's and POLR's obligations.

AEPSC commented that the commission's authority to verify operational limitations conflicts with the QF's ability to request dynamic scheduling in subsection (j)(3).

Additionally, RRI asserted that the proposed rule should be modified to ensure that the amount of the PURPA put energy scheduled or delivered to the PTB REP or POLR does not exceed the total load associated with those services. RRI recommended language to be added as subsection (j)(4), consistent with this recommendation.

The commission agrees with the parties that the term utility, in this rulemaking, should also apply to PTB REPs. It also agrees with RRI that language should be added to limit the amount of energy that may be put to a PTB REP to no more than the PTB REP needs to serve its load. If a QF chooses to use DRS, it does so with the understanding that it may have a different degree of notice available in case of curtailments due to operational concerns. The commission has made corresponding revisions to subsection (j)(4) consistent with the position that the amount of energy put may be limited.

§25.242(l), Interconnection costs

TXU proposed language to clarify that subsection (l) is addressing "electric" utility's Open Access Transmission Tariff.

The commission agrees with TXU and added "electric" in subsection (l) for clarity.

§25.242(m), System emergencies

AEPSC commented that subsection (m) it is not clear as to why PTB and POLR REPs cannot discontinue purchases and sales during a system emergency. The subsection should be amended or clarified.

The commission declines to make the revision suggested by AEPSC because the proposed rule did not recommend a change to this subsection. Therefore, no substantive change can be made to this provision at this time. However, the commission notes that a comparable provision exists in the FERC's rules relating to PURPA obligations at 18 C.F.R. §292.307.

25.242(n), Enforcement

AEPSC requested that the commission reject Texas QFs' suggestion that the commission evaluates via a contested case the compliance filings of each PTB and POLR REP. AEPSC argued that contested cases are not in the spirit of competition and that the commission should rely on market based prices instead.

In reply comments, Entergy REPs disagreed with Texas QFs' proposal that each implementation filing under the proposed rule be subject to review in a contested proceeding. Entergy REPs argued that affected parties have the ability under PURA and the commission's rules to initiate a complaint proceeding if disagreement exists with the implementation filing.

The commission believes Entergy's and AEPSC's concerns have been addressed by the deletion of subsection (i)(5).

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission makes other minor modifications for the purpose of clarifying its intent.

This amendment is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated, §11.002 (Vernon 1998 & Supplement 2002) (PURA), 16 U.S.C. §824a-3(f) (2000), and 18 C.F.R. Part 292 (2001) which grants the Public Utility Commission the authority to make and enforce rules necessary to protect customers of electric services consistent with the public interest; PURA §14.002 which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; PURA §35.061 which provides the commission with the authority to make and enforce rules to encourage the economical production of electric energy by qualifying facilities; and 16 U.S.C. §824a-3(f) (2000) and 18 C.F.R. Part 292 (2001), which require state regulatory authorities to implement federal Public Utility Regulatory Policies Act regulations addressing arrangements between certain entities that sell electric energy.

Cross reference to statutes: Public Utility Regulatory Act §§11.002, 14.002, and 35.061; 16 U.S.C. §824a-3; and 18 C.F.R. Part 292.

§25.242. Arrangements Between Qualifying Facilities and Electric Utilities.

(a) **Purpose**. The purpose of this section is to regulate the arrangements between qualifying facilities, retail electric providers with the price to beat obligation (PTB REPs), and electric utilities as required by federal and state law in a manner consistent with the development of a competitive wholesale power market.

(b) **Application.** This section shall apply to all PTB REPs, transmission and distribution utilities (TDUs), and electric utilities in Texas. This section shall not apply to municipal utilities, river authorities, or electric cooperatives.

(c) **Definitions.** The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise:

(1) **Avoided costs** — The incremental costs to a PTB REP, or electric utility of electric energy, which, but for the purchase from the qualifying facility or qualifying facilities, such PTB REP or electric utility would generate itself or purchase from another source.

(2) **Back-up power** — Electric energy or capacity supplied to replace energy or capacity ordinarily generated by a qualifying facility's own generation equipment during an unscheduled outage of the qualifying facility.

(3) **Cost of decremental energy** — The cost savings to a utility associated with the utility's ability to back-down some of its units or to avoid firing units, or to avoid

purchases of power from another utility because of purchases of power from qualifying facilities.

(4) **Electric utility** — For purposes of this section, an integrated investor-owned utility that has not unbundled in accordance with Public Utility Regulatory Act §39.051.

(5) **Firm power** — From a qualifying facility, power or power-producing capacity that is available pursuant to a legally enforceable obligation for scheduled availability over a specified term.

(6) **Host utility** — The utility with which the qualifying facility is directly interconnected.

(7) **Maintenance power** — Electric energy or capacity supplied during scheduled outages of the qualifying facility.

(8) **Market price** — The market-clearing price of energy (MCPE) in the balancing energy market for the Electric Reliability Council of Texas (ERCOT) congestion zone in which the power is produced, minus any administrative costs, including an appropriate share of ERCOT-assessed penalties and fees typically applied to power generators.

(9) **Non-firm power from a qualifying facility** — Power provided under an arrangement that does not guarantee scheduled availability, but instead provides for delivery as available.

(10) **Parallel operation** — A mode of operation which enables a qualifying facility to export automatically any electric capacity which is not consumed by the qualifying facility or the user of the qualifying facility's output. Parallel operation results in three possible states of operation at any point in time:

(A) The qualifying facility is generating an amount of capacity that is less than the customer's load. The customer is therefore a net consumer.

(B) The qualifying facility is generating an amount of capacity that is more than the customer's load. The customer is therefore a net producer.

(C) The qualifying facility is generating an amount of capacity that is equal to the customer's load. The customer is therefore neither a net producer nor a net consumer.

(11) **Purchase** — The purchase of electric energy or capacity or both from a qualifying facility by a PTB REP or electric utility.

(12) **Purchasing utility** — The electric utility that is purchasing a qualifying facility's capacity and/or energy.

(13) **Quality of firmness of a qualifying facility's power** — The degree to which the capacity offered by the qualifying facility is an equivalent quality substitute for firm purchased power or an electric utility's own generation. At a minimum the following factors should be considered in determining quality of firmness:

(A) reliability of generation and interconnection;

(B) forced outage rate;

(C) availability during peak periods;

(D) the terms of any contract or other legally enforceable obligation, including, but not limited to, the duration of the obligation, performance guarantees, termination notice requirements, and sanctions for noncompliance;

(E) maintenance scheduling;

(F) availability for system emergencies, including the ability to separate the qualifying facility's load from its generation;

(G) the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system;

(H) other dispatch characteristics;

(I) reliability of primary and secondary fuel supplies used by the qualifying facility; and

(J) impact on utility system stability.

(14) **Retail electric provider with the price to beat obligation (PTB REP)** — A REP that makes available a PTB pursuant to PURA §39.202.

(15) **Sale** — The sale of electric energy or capacity or both supplied to a qualifying facility.

(16) **Supplementary power** — Electric energy or capacity regularly used by a qualifying facility in addition to that which the facility generates itself.

(17) **System emergency** — A condition on a utility's system that is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(18) **Transmission and distribution utility (TDU)** — As defined in §25.5 of this title (relating to Definitions).

(d) **Negotiation and filing of rates.**

(1) **Negotiated rates or terms.** Nothing in this section shall:

(A) limit the authority of any PTB REP or electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differs from the rate or terms or conditions that would otherwise be required by this section; or

(B) affect the validity of any contract entered into between a qualifying facility and a PTB REP or electric utility for any purchase before the adoption of this section.

(2) **Filing of rates.** All rates for sales to qualifying facilities, contractual or otherwise, shall be contained in the schedule of rates of the electric utility filed with the commission.

(e) **Availability of electric utility system cost data.**

(1) **Applicability.** Paragraph (2) of this subsection applies to large electric utilities whose total sales of electric energy for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year. Paragraph (3) of this subsection applies to all other electric utilities.

(2) **Data request for large electric utilities.** Large utilities shall file the following data:

(A) the estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of one, ten and 100 megawatts or not more than 10% of the system peak demand for systems of less than 1,000 megawatts. The avoided cost shall be stated on a cents-per-kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next nine years.

(B) the electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding nine years.

(C) for the current year and each of the next nine years, the estimated capacity costs at completion of the planned capacity additions and planned capacity purchases, on the basis of dollars-per-kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt-hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases. Such information shall be submitted in accordance with the Federal Energy Regulatory Commission Regulations, 18 Code of Federal Regulations, §292.302 and shall be sufficient for qualifying facilities to reasonably estimate the utility's avoided cost. Accompanying each filing pursuant to this rule shall be a detailed explanation of how the data was determined, including sources and assumptions employed.

(3) **Special requirements for small electric utilities.** Affected utilities shall, upon request:

(A) provide to an interested person comparable data to that required under paragraph (2) of this subsection to enable qualifying facilities to estimate the electric utility's avoided costs; or

(B) with regard to an electric utility that is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide to an interested person the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(4) **Filing date.** By February 15 each year, large electric utilities shall file with the commission and shall maintain for public inspection the data set forth in paragraph (2) of this subsection.

(f) **PTB REP and electric utility obligations**.

(1) **Obligation to purchase from qualifying facilities.**

(A) In accordance with this subsection and subsection (g) of this section, each PTB REP and electric utility shall purchase any energy that is made available from a qualifying facility:

(i) directly to the PTB REP or electric utility; or

(ii) indirectly to the PTB REP or electric utility in accordance with paragraph (4) of this subsection.

(B) Each electric utility shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within 90 days of being notified by the qualifying facility that such energy is or will be available, provided that the electric utility has sufficient interconnection facilities available. If an agreement to purchase energy is not reached within 90 days after the qualifying facility provides such notification, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the 90th day following such notice. If the electric utility determines that adequate interconnection facilities are not available, the electric utility shall inform the qualifying facility within 30 days after being notified for distribution interconnection, or within 60 days for transmission interconnection, giving the qualifying facility a description of the additional facilities required as well as cost and schedule estimates for construction of such facilities. If an agreement to purchase energy is not reached upon completion of construction of the interconnection facilities or 90 days after notification by the qualifying facility that such energy is or will be available, the agreement, if and when achieved, shall bear a retroactive effective date for the purchase of energy delivered to the electric utility correspondent with the time of interconnection or the 90th day, whichever is later. Nothing in this subsection shall be construed in a manner that would preclude a qualifying facility from notifying and contracting for energy with a utility for sale of energy prior to 90 days before delivery of such energy.

(C) Each PTB REP shall purchase energy from a qualifying facility with a design capacity of 100 kilowatts or more within a timely fashion after being notified by the qualifying facility that such energy is or will be available.

(2) **Obligation to sell to qualifying facilities.** In accordance with subsection (k) of this section, each electric utility shall sell any energy and capacity requested to any qualifying facility located within the electric utility's service area. Each PTB REP shall also sell any energy requested to any qualifying facility; however, those sales shall be at market based rates. Nothing shall restrict the ability of any qualifying facility to purchase energy from any REP.

(3) **Obligation to interconnect.** The obligation of electric utilities and TDUs to interconnect with qualifying facilities is set forth in Subchapter I of this chapter (relating to Transmission and Distribution) with respect to qualifying facilities seeking to interconnect with TDUs in the ERCOT, and in the respective electric utility's Open Access Transmission Tariff for electric utilities in non-ERCOT power regions.

(4) **Transmission to other electric utilities.** Transmission service provided by an electric utility to a qualifying facility shall be governed by Subchapter I of this chapter.

(5) **PTB REP and scheduling with qualifying facilities.** A PTB REP shall use dynamic resource scheduling or responsibility transfer in ERCOT with any qualifying facility that requests such scheduling, as permitted by ERCOT. The PTB REP's cost of using dynamic resource scheduling or responsibility transfer attributable solely to purchases from qualifying facilities shall be charged to qualifying facilities that use such scheduling.

If a qualifying facility uses static scheduling, the qualifying facility shall bear the costs for any imbalances resulting from the qualifying facility's failure to submit a schedule or to comply with the schedule.

(g) **Rates for purchases from a qualifying facility.**

(1) Rates for purchases of energy and capacity from any qualifying facility shall be just and reasonable to the customers of the electric utility or PTB REP and in the public interest, and shall not discriminate against qualifying cogeneration and small power production facilities.

(2) Rates for purchases of energy and capacity from any qualifying facility shall not exceed avoided cost. Rates for purchase shall be based upon a market-based determination of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchase do not violate this subsection if the rates for such purchase differ from avoided cost at the time of delivery. Payments which do not exceed avoided cost shall be found to be just and reasonable operating expenses of the electric utility.

(3) A QF may agree to commit, on a day-ahead basis, to deliver firm power for the next day to a PTB REP. Rates for purchase of this power shall be based on prices for the day that the power was actually delivered as reported or published in an independent third party index or survey of trades of commonly traded power products in ERCOT, provided that the index or survey is ERCOT-specific and is based upon enough

transactions to represent a liquid market, and the commitment to deliver shall correspond with the relevant hours of delivery of those products.

(h) **Standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.**

(1) There shall be included in the tariffs of each electric utility standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. The rates for purchases under this paragraph:

(A) shall be consistent with subsection (g) of this section, as it concerns purchases from a qualifying facility;

(B) shall consider the aggregate capacity value provided by multiple qualifying facilities with a design capacity of 100 kilowatts or less; and

(C) may differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(2) Terms and conditions unique to qualifying facilities with a design capacity of 100 kilowatts or less such as metering arrangements, safety equipment requirements, liability for injury or equipment damage, access to equipment and additional administrative costs, if any, shall be included in a standard tariff.

(3) The standard tariff shall offer at least the following options:

(A) parallel operation with interconnection through a single meter that measures net consumption;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production will not be metered or purchased by the utility and therefore there will be no additional customer charge imposed on the qualifying facility;

(B) parallel operation with interconnection through two meters with one measuring net consumption and the other measuring net production;

(i) net consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs;

(ii) net production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection;

(C) interconnection through two meters with one measuring all consumption by the customer and the other measuring all production by the qualifying facility;

(i) all consumption by the customer for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the customer would belong in the absence of the qualifying facility;

(ii) all production by the qualifying facility for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) and (B) of this subsection.

(4) In addition, each electric utility shall offer qualifying facilities using renewable resources with an aggregate design capacity of 50 kilowatts or less the option of interconnecting through a single meter that runs forward and backward.

(A) Any consumption for a given billing period shall be billed in accordance with the standard tariff applicable to the customer class to which the user of the qualifying facility's output belongs.

(B) Any production for a given billing period shall be purchased at the standard rate provided for in paragraph (1)(A) of this subsection.

(5) Interconnection requirements necessary to permit interconnected operations between the qualifying facility and the utility and the costs associated with such requirements shall be dealt with in a manner consistent with Subchapter I of this chapter.

(6) The rates, terms and conditions contained in the standard tariff for qualifying facilities with a design capacity of 100 kilowatts or less shall be subject to review and revision by the commission.

(7) Requirements for the provision of insurance under this subsection shall be of a type commonly available from insurance carriers in the region of the state where the customer is located and for the classification to which the customer would belong in the absence of the qualifying facility. An enhancement to a standard homeowner's or farm and ranch

owner's policy containing adequate liability coverage and having the effect of adding the electric utility as an additional insured or named insured is one means of satisfying the requirements of this paragraph. Such policies shall in each instance be on a form approved or promulgated by the Texas Department of Insurance and issued by a property or casualty insurer licensed to do business in the State of Texas.

(i) **Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility.** Tariffs setting out the methodologies for purchases of nonfirm power from a qualifying facility shall be filed with the commission based on one of the following approaches:

(1) Rates for purchases of nonfirm power may, by agreement of both the electric utility and the qualifying facility, be based on the utility's average avoided energy costs. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(2) PTB REPs and QFs may mutually agree to rates for purchases of nonfirm power that differ from the rates described in paragraph (4) of this subsection. Any such agreements shall be made on a nondiscriminatory basis. Such agreements may include provisions to prevent the potential for arbitrage.

(3) Rates for purchases of nonfirm power may, at the option of the qualifying facility, be based on the full cost at the time of delivery of decremental energy that would have been incurred by the electric utility had the qualifying facility not been in operation.

(A) The following factors should be considered in the calculation of the cost of decremental energy:

(i) fuel costs;

(ii) variable operating and maintenance costs;

(iii) line losses;

(iv) heat rates;

(v) cost of purchases from other sources;

(vi) other energy-related costs;

(vii) capacity costs, if, as a class, qualifying facilities providing nonfirm energy offer some predictable capacity; and

(viii) for short term energy purchases, the time and quantity of energy furnished.

(B) If practical, the avoided cost should be determined by calculating by time period, using the utility's economic dispatch model (or comparable methodology), the difference between the cost of the total energy furnished by both the qualifying facility and the utility, computed as though the energy furnished by the qualifying facility had been furnished by the utility, and the actual cost of energy furnished by the utility.

(C) The economic dispatch model should take into consideration the following factors:

(i) fuel costs;

(ii) variable operating and maintenance costs;

(iii) line losses;

(iv) heat rates;

(v) purchased power opportunity;

(vi) system stability; and

(vii) operating characteristics.

(D) Time periods should be hourly if the utility has an automated economic dispatch model available; otherwise the shortest reasonable time period for which costs can be determined should be used.

(E) Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility.

(4) Rates for purchases of nonfirm power shall be based on the market price of energy at the time of sale from the QF unless other arrangements have been made in accordance with paragraph (2) of this subsection. Administrative, billing, and metering costs shall be recovered through a monthly customer charge to the qualifying facility. Such agreements may include provisions to prevent the potential for arbitrage.

(j) **Periods during which purchases not required.**

(1) Any PTB REP or electric utility which gives notice to each affected qualifying facility in time for the qualifying facility to cease delivery of energy or capacity to the PTB REP, or electric utility will not be required to purchase electric energy or capacity during any

period during which, due to operational circumstances, including resource ramp rate limitations that could cause imbalances or the amount of energy put by the QF exceeds the PTB REP's load, purchases from qualifying facilities will result in costs greater than those which the electric utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself, provided, however, that this subsection does not override contractual obligations of the PTB REP or electric utility to purchase from a qualifying facility.

(2) Any PTB REP or electric utility which fails to give notice to each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the PTB REP or electric utility will be required to pay the same rate for such purchase of energy or capacity as would be required had the period of greater costs not occurred.

(3) A claim by PTB REP or an electric utility that such a period has occurred or will occur is subject to such verification by the commission either before or after the occurrence.

(k) **Rates for sales to qualifying facilities.**

(1) **General rules.**

(A) Rates for sales to qualifying facilities shall be just and reasonable and in the public interest, and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility. Rates for standby or other supplementary service shall be based on the amount of capacity contracted for between the qualifying facility and the electric utility, and shall not penalize electric utilities that also purchase power from qualifying facilities. The need for and cost responsibility for special equipment or system modifications shall be determined by application of Subchapter I of this chapter.

(B) Rates for sales that are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the electric utility's other customers with similar load or other cost-related characteristics.

(2) **Additional services to be provided to qualifying facilities.**

(A) Upon request of a qualifying facility within its service area, each electric utility shall provide:

(i) supplementary power;

(ii) back-up power;

(iii) maintenance power; and

(iv) interruptible power.

(B) An electric utility shall not be required to provide supplementary power, back-up power, or maintenance power to a qualifying facility if the commission finds that provision of such power will:

(i) impair the electric utility's ability to render adequate service to its customers; or

(ii) place an undue burden on the electric utility.

(3) **Rates for sales of back-up power and maintenance power**. The rate for sales of back-up power or maintenance power:

(A) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(B) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

(l) **Interconnection costs.** The establishment and reimbursement of interconnection costs are set forth in Subchapter I of this chapter with respect to qualifying facilities seeking to interconnect with TDUs in ERCOT, and in the respective electric utility's Open Access Transmission Tariff for electric utilities in non-ERCOT power regions.

(m) **System emergencies.**

(1) **Qualifying facility obligation to provide power during system emergencies.** A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(A) provided by agreement between such qualifying facility and electric utility; or

(B) ordered under the Federal Power Act, §202(c).

(2) **Discontinuance of purchases and sales during system emergencies.** During any system emergency, an electric utility may discontinue:

(A) purchases from a qualifying facility if such purchases would contribute to such emergency; and

(B) sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

(n) **Enforcement.** A proceeding to resolve a dispute between an electric utility, PTB REP and a qualifying facility arising under this section may be instituted by filing of a petition with the commission. Electric utilities, PTB REPs, and qualifying facilities are encouraged to engage in alternative dispute resolution prior to the filing of a complaint.

This agency hereby certifies that the rule, as adopted, has been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.242 relating to Arrangements Between Qualifying Facilities and Electric Utilities is hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 20th DAY OF JUNE 2002.

PUBLIC UTILITY COMMISSION OF TEXAS

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Rebecca Klein, Chairman

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Brett A. Perlman, Commissioner