

Agencies); the Steering Committee of Cities Served by Oncor (Oncor Cities); Texas Industrial Energy Consumers (TIEC); Wal-mart Stores Texas LLC and Sam's East Inc. (collectively, Walmart); and State Representative Sylvester Turner (District 139).

Public Hearing

On August 15, 2011, at the request of Oncor Cities, State Agencies, and TIEC, commission staff conducted a public hearing in this proceeding. Parties' statements at the public hearing were generally similar with their filed written comments, but where different are noted below.

General Comments

Electric Utilities indicated general support for the proposal and a belief that, for the most part, the proposal effectively implements SB 1693. Electric Utilities emphasized the benefits of the rules and procedures adopted by the commission for the recovery of transmission costs, specifically noting the support for and timely recovery of transmission investment, and argued that properly crafted rules for recovery of distribution investment should produce similar benefits.

REP Coalition stated that the proposed rule reasonably limits DCRF updates to once per calendar year, ensures system-wide application of an approved DCRF, and requires a minimum 45-day notice period for an approved DCRF before it becomes effective. REP Coalition emphasized the important role that each of these requirements plays in REP Coalition's preparation for and implementation of an electric utility's DCRF.

COH stated that it understands the overall purpose and potential benefits to ratepayers, utilities, and regulators of implementing an automatic cost adjustment mechanism such as the periodic rate adjustment provided in Public Utility Regulatory Act (PURA) §36.210, and noted that any commission rule to implement such a mechanism must be properly designed and executed, requiring an ongoing collaborative process between the utility and the regulators. In addition, COH alleged that the proposed rule exceeds the PURA §36.210 grant of authority to the commission, shifts the overall risk to the ratepayers, and frustrates the statutory safeguards the Texas legislature (Legislature) chose to enact.

State Agencies argued that the proposed rule does not achieve the statutory goals of SB 1693 because the proposed rule (1) proposes a formula that reallocates distribution costs in a manner that changes the allocation from the prior base rate case, by failing to properly account for load growth revenues; (2) undercuts discovery rights of public participants; (3) truncates substantive staff review of the applications; (4) improperly delegates approval or disapproval of costs to a “presiding officer” other than the commission or the State Office of Administrative Hearings; and, (5) does not include a clear mechanism for disallowing, from inception, requests from utilities who are over-earning.

CORE recognized that the establishment of a DCRF is pursuant to the commission’s new statutory authority to approve periodic rate adjustments relating to changes in an electric utility’s distribution invested capital. However, CORE contended that the provisions of the proposed rule do not comply with the requirements of SB 1693, exceed the authority granted to the commission in SB 1693, and violate PURA §§32.002, 33.001, 36.108, and 36.111.

OPC contended that the purpose of the DCRF adjustment is to provide an abbreviated ratemaking process for an electric utility to petition the commission for an adjustment of its non-fuel rates to incorporate changes in only the utility's distribution invested capital since its most recent general base rate case, and that PURA §36.210 does not authorize and was never intended to serve as a mechanism for the electric utilities to be granted what OPC calls "lost revenues." OPC stated that PURA §36.210 requires that an electric utility's petition for a DCRF be processed in accordance with an expedited procedure, and suggested that the best way to expedite and simplify the DCRF procedure is to state as clearly and specifically as possible in the rule what is eligible for inclusion in a DCRF adjustment and what an electric utility must include in its application and prove to obtain a DCRF adjustment.

Oncor Cities stated that the proposed rule accurately reflects the requirements of PURA §36.210 in most respects, but in several significant ways departs from the framework set forth by the new statute. Oncor Cities noted that proponents of the streamlined distribution ratemaking concept have analogized it to the interim transmission cost of service (TCOS) or the transmission cost recovery factor (TCRF) mechanisms. Oncor Cities argued, however, that the statutory authority giving rise to those devices is not analogous to PURA §36.210. Comparing and contrasting the two statutes, Oncor Cities pointed out that PURA §35.004, the interim TCOS mechanism, states simply that "the commission may approve wholesale rates that may be periodically adjusted to ensure timely recovery of transmission investment," whereas PURA §36.210 contains a great deal of detail regarding the new distribution cost recovery mechanism rather than a broad-brush grant of authority that assumes that the commission will provide all relevant details of the new

recovery mechanism via a rule. Oncor Cities argued that the additional detail that PURA §36.210 puts into the DCRF mechanism reflects the legislative understanding that distribution charges have a far greater bill impact compared to the charges that are established in the interim TCOS process. Oncor Cities explained that distribution charges are not socialized across the Electric Reliability Council of Texas (ERCOT) region and remain in the footprint of the utility; therefore, distribution charges have a larger impact on the bills of any particular customer compared to transmission charges.

Oncor Cities also commented that the proposed rule is very favorable to the utilities, providing advantages such as limitations on discovery, short timelines for approval, and limitations on the scope of review before the relevant costs begin to be recovered.

Commission Response

Section 2 of SB 1693 requires the commission to adopt rules as necessary to implement new PURA §36.210 not later than September 25, 2011—120 days after SB 1693 was enacted and took effect. New §25.243, adopted herein, meets this requirement. The commission addresses in the discussion below specific issues raised in the parties' general comments.

Comments on Specific Sections of the Proposed Rule

Section 25.243(b): Definitions

As discussed below concerning *Proposed 25.243(b)(2): Distribution Invested Capital*, the commission has added a definition of net distribution invested capital and included it as §25.243(b)(4) of the adopted rule. In addition, as discussed below concerning

§25.243(c)(1): *Application for DCRF or DCRF Update—General Requirements*, the commission has defined “DCRF proceeding” and included it as §25.243(b)(2) of the adopted rule.

Section 25.243(b)(1): Capitalized O&M Expenses

Representative Turner commented on an amendment to SB 1693 that he sponsored. Representative Turner commented that his amendment prohibiting capitalized operations and maintenance (O&M) expenses (and indirect corporate costs) from being recovered through the periodic rate adjustment mechanism was an important safeguard for Texas ratepayers. Representative Turner also stated that he is concerned that the proposed rule substantially weakens this protection and does not reflect his intent, which included no exceptions to the prohibition. Representative Turner observed that the proposed definition of capitalized O&M provides leeway for utilities to recover expenses that were never intended to be subject to the new mechanism. Representative Turner expressed concern that the definition is too narrow and that utilities may attempt to broaden the scope of SB 1693 by accounting for their O&M expenditures in a different manner.

Oncor Cities also commented on Representative Turner’s amendment. Oncor Cities stated that the amendment represented a concern by legislators that electric utilities could attempt to expand the scope of costs that can be flowed through the DCRF by classifying expenses as capital items or by including executive pay increases or bonuses, office supplies, and the like as overhead costs for new capital projects. Oncor Cities further commented that SB 1693 was represented to legislators as a cost recovery mechanism that would be strictly limited to the cost

of constructing and installing new distribution facilities. Oncor Cities stressed that given the importance of this amendment in protecting ratepayers from abuse of the DCRF mechanism, the definition of capitalized O&M expenses should be strengthened. Oncor Cities also noted that the exclusion of costs eligible for DCRF recovery does not preclude the utility from requesting recovery of the costs in a subsequent full base rate case.

Oncor Cities agreed that capitalized O&M expenses should be excluded from recovery through the DCRF but commented that the proposed rule's definition may not be broad enough to limit efforts by utilities to circumvent the intent of the law. Oncor Cities contended that the definition should preclude any attempt by utilities to recover an expense through the DCRF even if the utility has not labeled the cost as a regulatory asset or liability. Oncor Cities expressed concern that a utility should not be permitted to circumvent this definition by capitalizing an estimated (rather than incurred) expense. Oncor Cities also proposed language that would exclude amortization of a regulatory asset or liability. Electric Utilities disagreed that utilities could potentially attempt to circumvent the intent of the DCRF rule by attempting to recover expenses that have not been labeled as a regulatory asset or liability, but agreed conceptually with Oncor Cities' proposed modifications to the definition and supported the addition of the phrases "or estimated" and "or amortized" as suggested by Oncor Cities.

Oncor Cities also proposed language that would exclude the costs of activities normally recorded in O&M accounts (Federal Energy Regulatory Commission (FERC) Accounts 500-935). Electric Utilities argued that Oncor Cities' proposed language is superfluous given the

fact that the phrase “incurred or estimated expenses” is inclusive of expenses recorded in FERC Accounts 500-935 and thus should not be included in the definition.

Oncor Cities further opined that one reason the statute addresses O&M expense is that utilities may attempt to blur the line between repair and maintenance costs and investment in new distribution facilities through accounting interpretations that treat items such as inspection and testing of distribution facilities, cleaning and repairing distribution equipment, replacing transformers and voltage regulators, and tree trimming as part of its construction program rather than as O&M expense. Oncor Cities expressed concern that the commission would have difficulty differentiating the costs from general distribution construction and identifying the issue in a DCRF proceeding.

Electric Utilities replied that it is not entirely clear what expenses Oncor Cities refer to, because Oncor Cities combine replacement of transformers, which can be a capital-related project if the replacement was due to load growth, with true O&M activities such as inspection and testing of distribution facilities. Electric Utilities noted that if Oncor Cities’ proposal is intended to exclude costs like engineering and design labor and construction labor from invested capital, then Electric Utilities disagree. Electric Utilities argued that accounting rules require them to add the cost associated with the labor required to install a distribution pole to the actual cost of the pole when that work order is closed and the total amount is recorded in FERC Account 364 (poles, towers and fixtures). Electric Utilities pointed out that that practice is consistent across the industry and has been recognized by the commission in rates since its inception.

Commission Response

To address Representative Turner's and Oncor Cities' concern about an electric utility changing the way that it accounts for O&M expenditures in order to increase recovery through its DCRF, the commission has added subsection (d)(3), which provides that the electric utility must clearly identify any costs included as distribution invested capital because of a change in accounting rules or practices since the test year in the electric utility's most recent comprehensive base-rate proceeding. The commission shall exclude such costs if the electric utility does not prove that the costs are appropriate for recovery through the DCRF. In addition, the commission has changed the definition of capitalized O&M expenses to refer generally to "expenses" rather than "incurred expenses" and included a reference to amortized expenses in order to avoid unintentionally narrowing the definition, and thereby unintentionally broadening cost recovery through the DCRF.

*Proposed §25.243(b)(2): Distribution Invested Capital**Comments Regarding the Inclusion of Specific FERC Accounts*

CORE, COH, and Oncor Cities proposed that the definition of "distribution invested capital" be modified to exclude Account 391, relating to office furniture and equipment from the list of Federal Energy Regulatory Commission (FERC) Uniform System of Accounts on which the definition is based. CORE argued that distribution invested capital should only include items directly related to the provision of electric service using distribution facilities and that office furniture and equipment are not distribution facilities and should not be treated as invested

capital that the utility may recover through the DCRF. Oncor Cities commented that Account 391 is a general plant account for office furniture and equipment that may include costs that fall within the ambit of indirect corporate costs, which are specifically excluded from DCRF recovery. Oncor Cities also noted that the FERC chart of accounts lists costs recordable in Account 391, and none of the costs is related to communications equipment. Oncor Cities argued that Account 391 includes indirect corporate costs, and does not include either distribution plant or distribution-related communications plant, so this account should not be included in the definition of distribution invested capital.

Electric Utilities replied that these parties suggested that FERC Account 391 should be excluded from the list of FERC accounts that are included in the definition of distribution invested capital merely because that account is labeled office furniture and equipment. Electric Utilities further replied that Oncor Cities also suggested that FERC Accounts 352 and 353 (discussed below) should be excluded from the definition because they are designated as transmission plant accounts. Electric Utilities claimed that these suggestions incorrectly assume that the listing of a FERC account in the definition necessarily means that the entirety of amounts recorded in that account is recoverable under a DCRF. Electric Utilities pointed out that Account 391 — Office Furniture and Equipment does include general office furniture such as desks, chairs, etc., but is also used by a number of electric utilities to book computer-related equipment, including servers. According to Electric Utilities, Unique Property Unit Numbers, also a FERC requirement, are used to further categorize specific plant items that fall under the general header of office furniture and equipment such that specific types of property can be readily identified within the broader category. Electric Utilities contended that the use of

Property Unit Numbers is necessary because all possible plant items that exist today do not neatly fit into one of the FERC broader categories. Electric Utilities pointed out that it can be argued that the FERC system of accounts was created before the advent of computers, which is the reason no specific FERC account references computer hardware, or software for that matter. Electric Utilities argued that this omission does not lessen the fact that computer hardware is a reality of our time and is in fact plant that is recoverable through the rate base in base-rate case proceedings, and to the extent that it is distribution-related, should be recoverable through the DCRF.

Electric Utilities proposed that to ensure that they do not include costs for plant that are not directly related to the provision of distribution service, a query of these Property Unit Numbers will produce the amount of plant associated with computer-related equipment that has been booked to FERC Account 391 or any other FERC account that an electric utility may use to book such assets. Electric Utilities noted that in this manner, visibility can readily be provided, thereby ensuring that utilities do not seek to recover items that are precluded from recovery under the DCRF. Electric Utilities reiterated that because computer hardware that is directly used in the provision of distribution service is booked to this account by multiple electric utilities, FERC Account 391 must remain in the list of accounts that define distribution invested capital to ensure that this invested capital is capable of being recovered.

Commission Response

To fall within the rule's definition of distribution invested capital, invested capital must be:
(1) categorized as distribution plant, distribution-related intangible plant, or distribution-

related communication equipment and networks; and (2) properly recorded in FERC Accounts 303, 352, 353, 360 through 374, 391, or 397. Certain types of invested capital that directly relate to the distribution system are properly booked to FERC Account 391. However, invested capital that is not directly related to the distribution system but is booked to FERC Account 391 does not fall within the definition of distribution invested capital. Exclusion of this account could preclude invested capital that directly relates to the distribution system from recovery through the DCRF, a result that would be contrary to PURA §36.210. The commission therefore declines to exclude all invested capital in FERC Account 391 from the definition of distribution invested capital.

Oncor Cities commented that in addition to excluding Account 391, the definition of distribution invested capital should not include FERC Accounts 352 or 353 because the law limits recoverable costs to distribution investment and these accounts are designated by the FERC Chart of Accounts as transmission plant accounts. Oncor Cities argued that PURA §36.210(a) references the FERC uniform system of accounts as a basis for defining distribution plant and that PURA §36.210(f)(3) specifically prohibits the inclusion of costs recoverable through a transmission cost recovery factor. Oncor Cities expressed concern that inclusion of Accounts 352 and 353 could result in the double recovery of costs that are currently recovered through TCOS rules.

Electric Utilities replied that Oncor Cities' argument reflects a narrow view of FERC accounting principles and noted that while FERC Accounts 352 and 353 appear to be solely transmission-related and thus ineligible for inclusion in a DCRF filing, that is not the case. According to

Electric Utilities, Accounts 352 and 353 include structures and improvements and station equipment related to substations, which can be classified as either transmission substations or distribution substations, depending on the primary function of the substation. Electric Utilities explained that for substations classified as transmission substations, the primary function is a transmission switching station; however, distribution transformers and equipment can also be present in these stations to provide distribution-level service as a secondary function. Electric Utilities further noted that in stations with this configuration, the transformers that transform power from transmission voltage (at or above 60 kilovolt (kV)) to distribution voltage (below 60 kV) as well as the associated facilities on the low side of the transformer are booked to FERC Accounts 352 and 353, but are functionalized to distribution since they support the provision of distribution service. Electric Utilities commented that the portions of the facilities in these stations that are operated at or above 60 kV are functionalized to transmission.

Electric Utilities emphasized that in the TCOS filings, the entirety of FERC Accounts 352 and 353 is not included for this very reason and that only the portions of the accounts functionalized to transmission are included in the TCOS filing, thus ensuring that no distribution-related plant is recovered through the TCOS process. Electric Utilities pointed out that in this same manner, only the portions of Accounts 352 and 353 that are functionalized to distribution would be recoverable under a DCRF, not the entirety of Accounts 352 and 353. Electric Utilities commented that PURA §36.210(f)(3) requires the exclusion of any transmission costs from the DCRF, so that the chance that the same costs are double-recovered through the TCOS and DCRF are eliminated.

Electric Utilities noted that inclusion of these FERC accounts, or any other FERC account, in the definition of distribution invested capital will not permit Electric Utilities to seek recovery of all costs included in these accounts through the DCRF process. Electric Utilities replied that the proposed rule clearly articulates that only the portions of these accounts that are categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks are recoverable through a DCRF. Electric Utilities assured that to the extent that costs related to transmission service, desks, chairs, or any other items not directly related to the provision of distribution service are found in these accounts, they will be excluded from Electric Utilities' DCRF applications.

Commission Response

As with FERC Account 391, discussed above, certain types of invested capital that directly relate to the distribution system are properly booked to FERC Accounts 352 and 353. In addition, §25.192(c)(1)(B) (relating to Transmission Service Rates) requires the exclusion of distribution facilities in FERC Accounts 352 and 353 in the calculation of wholesale transmission rates, thereby addressing Oncor Cities' concern about double recovery. Therefore, the commission declines to exclude all invested capital in these accounts from the definition of distribution invested capital.

Other Issues Related to Plant Accounts and Invested Capital

COH was concerned that the rule fails to specifically require the utility to include all plant accounts in the DCRF proceeding, as this could result in the utility exercising the option to include only those accounts that increase while excluding any that may have decreased since the

last rate change. OPC and Oncor Cities agreed, and OPC commented that utilities should not be allowed to game the system by including only increases in distribution invested capital in a DCRF application while omitting decreased distribution invested capital costs. OPC recommended that this requirement be added to the General Instructions for the DCRF rate filing package. COH also proposed that the DCRF rule require the utility to reflect known and measurable changes, just as it does in a base rate case.

Commission Response

The commission has added a provision to the definition of distribution invested capital to preclude the gaming possibility identified by COH. The commission declines to require or permit adjustments for known and measurable changes to distribution invested capital. Under §25.231(c)(2)(F) (relating to Cost of Service), determining whether and how to make a known and measurable adjustment to invested capital in a comprehensive base-rate proceeding can involve a number of considerations. Considering adjustments for known and measurable changes to distribution invested capital would add significant complexity to a DCRF proceeding, which would undermine PURA §36.210(a)(1)'s requirement that the proceeding be expedited. In addition, such adjustments are likely to be relatively small. The commission also notes that, although COH's comments on the proposed rule generally expressed concern about excessive recovery through a DCRF, its proposal to allow known and measurable adjustments would likely increase DCRF cost recovery in most cases, because an electric utility's net distribution invested capital generally increases over time due to factors such as load growth and inflations, as well as possibly smart grid investments. As discussed below concerning proposed subsection (b)(3), the commission

has changed subsection (b)(2) to expressly address compliance with PURA §36.058.

COH proposed that the DCRF rule contain appropriate language in §25.243(b)(2) that clearly limits allowable cost recovery to new invested capital. COH argued that the rule must clearly prohibit any attempt at correcting prior accounting errors through the DCRF filing, because such accounting changes are not associated with completion of new capital projects. The concern expressed by COH is the possibility that such inclusion could result in an artificial increase in revenue requirement because of the correction of errors that transpired many years ago. Oncor Cities concurred with the recommendation of COH related to expressly limiting allowable cost recovery to new invested capital.

Electric Utilities disagreed and urged the commission to reject the proposed change, arguing that in its comments, COH seems to suggest that accounting corrections are improper rather than recognize the fact that true accounting errors can and do sometimes happen. Electric Utilities pointed out that COH also appears to not recognize that accounting errors can go both ways, and the correction of an accounting error may work in the customers' interest by reducing the amount of the request. Electric Utilities further replied that if an error has been discovered, it is incumbent on the utility to make corrections to the official books and records of the company at the point when the error is discovered. Electric Utilities pointed out that since the DCRF process is heavily dependent on the official books and records of the company, COH's proposal would require electric utilities to either knowingly carry forward erroneous balances in FERC accounts, which would be a violation of accounting standards, or maintain two separate instances of records, one that would represent the official books and records and the other that

carries forward the incorrect balance. Electric Utilities urged that either option is fraught with problems and has the potential to complicate both the DCRF filings as well as the proper maintenance of the company's financial records and for these reasons, COH's suggestion should be rejected.

Commission Response

The commission is persuaded by the Electric Utilities' comments. No change is warranted.

Comments related to Accumulated Deferred Federal Income Taxes (ADFIT)

Oncor Cities, CEP, COH, CORE, TIEC, and OPC commented that the definition of distribution invested capital should be modified to recognize the deduction of ADFIT. Oncor Cities argued that the proper recognition of revenue requirements associated with changes in distribution plant investment should take into account distribution-related ADFIT because ADFIT represents ratepayer-supplied funds for taxes not yet required to be remitted to the U.S. Treasury. Oncor Cities reasoned that ADFIT reduces the distribution rate base in order to recognize the benefits that the company receives from the differences between tax depreciation and depreciation for ratemaking purposes and that fairness requires that ratepayers receive the benefits of ADFIT in rates.

COH and CORE contended that while PURA §36.053 limits distribution-related invested capital to original cost less depreciation or net plant, the commission, by rule and practice, has established the definition to include other components of rate base. COH noted that §25.231(a), relating to Components of Cost of Service, identifies allowable expenses and return on invested

capital as the two components of cost of service employed for ratemaking purposes and that the commission, by rule and practice, has always allowed utilities to earn a return on invested capital not limited to the original cost less depreciation, but inclusive of all components of rate base. CEP claimed that the term invested capital is a term of art, and is a carryover from the usage in the original 1975 version of PURA that expressed rate base and the return on rate base in terms of invested capital and the adjusted value of invested capital. CEP argued that since the earliest days of the commission, ADFIT has been included in the calculation of invested capital (or original cost rate base) and that the offset is required by the normalization provisions of the Internal Revenue Code.

COH claimed that consistent application of the definition of invested capital as employed by the commission would require recognition of changes in ADFIT and that the change in ADFIT each year is predominantly tied to the change in plant in service. COH argued that to recognize changes in plant only as net plant, without the corresponding rate base components, is inconsistent with existing rules and current commission practice and presents contradictory definitions of invested capital as it applies to rates charged to customers.

OPC commented that including ADFIT in the DCRF formula is warranted because the DCRF calculation in the proposed rule includes consideration of changes in the utility's current federal income taxes and other taxes associated with the changes in invested capital. OPC contended that disregarding changes in the utility's current ADFIT balance while including changes in the utility's current federal income taxes, to which the ADFIT balance is closely related, in the DCRF formula is unduly preferential to the utilities, and appears arbitrary and capricious. OPC

maintained that changes in the utility's current ADFIT balance associated with changes in invested capital must be included in the calculation of the DCRF rates if federal income taxes and other associated taxes are included in the DCRF calculation.

OPC contended that the ADFIT must be considered in DCRF adjustments so that a utility will not be enabled by DCRF adjustments to receive a greater rate of return than authorized in the utility's most recent base rate case. OPC maintained that not deducting ADFIT from the invested capital included in a DCRF adjustment would result in the utility realizing a greater rate of return than authorized, which contravenes PURA §36.210, because the utility would be receiving additional return on the cost-free ADFIT capital. OPC pointed out that nothing requires a utility to apply for a DCRF adjustment on an annual basis. Consequently, even though a utility is limited to four DCRF adjustments between base-rate proceedings, under the proposed DCRF formula, invested capital can be included in a utility's DCRF rates for several years without any recognition of substantial ADFIT associated with the invested capital until new base rates are later determined in a base rate case. OPC argued that not accounting for ADFIT associated with invested capital included in rates through the DCRF is totally inconsistent with traditional ratemaking principles, which were not changed by PURA §36.210 and still prevail, and will consequently result in not only a greater rate of return for the utility than authorized in the most recent base rate case, but also rates that are unreasonable and unfair to consumers.

COH commented that the proposed rule would allow the utility to recover both increased depreciation expense and increased income tax expense, but does not reflect the impact these

changes have on ADFIT. COH pointed out that in CenterPoint's last base rate filing (Docket Number 38339), ADFIT reduced the distribution rate base by 20% and, other than net plant, was the most significant item in the distribution rate base. COH argued that the accumulated provision for depreciation and ADFIT are the two most significant rate-base offsets and it is only through recognition of these offsets that the DCRF could result in a rate decrease as PURA §36.210(a) contemplates. COH maintained that to exclude ADFIT in the context of the DCRF rule not only exceeds the intended scope of PURA §36.210, but also conflicts with the plain language of PURA §36.210 (a) that clearly contemplates an upward or downward adjustment of rates. COH argued that unless the DCRF rule includes offsets to rate base that could exceed plant increases in a given year, no potential rate decrease is possible. CORE concurred with this observation.

Oncor Cities and TIEC contended that the inclusion of new distribution plant in rate base should produce additions to the ADFIT balance over time. Oncor Cities maintained that assuming a utility will use multiple DCRF updates in between full rate cases, the ADFIT balance may increase over time and should be used to partially offset the higher revenue requirements associated with the new plant investment. Oncor Cities and TIEC also proposed exclusion of the impact of Financial Accounting Standards Board Interpretation No. 48 (FIN 48) on ADFIT, which they maintained is consistent with the commission's most recent decisions with respect to FIN 48, and avoids litigation of the FIN 48 issue in the DCRF/DCRF update proceeding.

OPC, CEP, and COH pointed out that the ADFIT issue is exacerbated by the bonus depreciation arising from the Tax Relief, Unemployment Insurance Reauthorization, and Job

Creation Act of 2010, Public Law 111-312 (2010), which created a 100% deduction for capital investment placed in service after September 8, 2010 and before December 31, 2011, and a 50% deduction through December 31, 2012. COH and OPC also claimed that federal legislation establishing bonus depreciation typically has a significant impact on the level of ADFIT since bonus depreciation results in additional income tax savings to utilities. COH contended that this savings is typically passed through to the ratepayers through ADFIT, and therefore the exclusion of ADFIT serves to further detach the rule from existing law. COH maintained that because of the state of the economy, a bonus depreciation extension beyond 2012 is anticipated.

COH commented that the overall purpose of SB 1693 and the implementing rule is to provide for timely cost recovery. COH contended that inclusion of ADFIT does not slow down or interfere with a timely cost recovery process. COH and CORE claimed that it has been suggested that the exclusion of ADFIT would provide additional encouragement to utilities to invest in new infrastructure, but that that is not the intent or purpose of the bill. OPC claimed that like the issue of prudence, the calculation of a utility's ADFIT balance is rarely challenged in electric utility rate cases, is not an issue that typically involves extensive discovery or litigation, and its inclusion in the formula would not complicate DCRF adjustment cases or conflict with the DCRF mechanism's purpose of providing an expedited procedure. COH stressed that ADFIT is an indispensable component in the quantification of invested capital and argued that the DCRF process was never intended to afford a utility an unwarranted level of return while eliminating regulatory lag for infrastructure expenditures. COH emphasized that failure to consistently recognize ADFIT in the DCRF rate-setting process inappropriately enriches a utility beyond the special rate treatment being afforded to it through the DCRF process. COH

commented that ADFIT associated with the precise plant recognized in a DCRF request must also be simultaneously recognized.

Electric Utilities replied that they strongly support the exclusion of ADFIT for several reasons. Electric Utilities stressed that the interim TCOS process does not take into account any changes in ADFIT, and SB 1693 was adopted to clearly authorize the commission to implement a rate adjustment for distribution investment that is very similar to the interim TCOS adjustment applicable to transmission investment. Electric Utilities commented that the basics of the DCRF adjustment formula, unless otherwise addressed by the statute, should be the same as the interim TCOS formula. Electric Utilities noted that whether to include ADFIT in the DCRF calculation was also considered in the earlier DCRF rulemaking, Project Number 38298, with Oncor Cities proposing it be included. Electric Utilities observed that while the commission ultimately did not act on that proposed rule, waiting instead for the Legislature to have an opportunity to address the topic of distribution cost recovery and provide guidance, staff's proposed rule did not include ADFIT. Electric Utilities submitted that staff's proposed resolution of this issue in Project Number 38298 was correct and should be adopted here.

Electric Utilities acknowledged that while the city groups are correct that new capital additions may produce additional ADFIT, including those amounts resulting from the application of bonus depreciation (which is due to expire at the end of 2012), what those entities ignore is that payment of taxes reduces ADFIT. Electric Utilities commented that ADFIT is no different than any other rate base component — it changes over time. Electric Utilities argued that if the DCRF proceeding is not to morph into a general rate case, then the

items that are adjusted must be kept to a minimum. Electric Utilities pointed out that although ADFIT changes over time, so do regulatory assets (insurance reserve, pensions), cash working capital, plant held for future use, and other components of rate base. Electric Utilities urged that those items are all properly excluded from the DCRF formula, and ADFIT is likewise properly excluded from the DCRF formula.

Electric Utilities commented that the arguments of CEP and COH that the language in PURA §36.210(a) requires the inclusion of ADFIT because it is a component of invested capital fail, because PURA §36.053 explicitly refers only to “the original cost, less depreciation, of property used by and useful to the utility in providing service” and does not specifically refer to ADFIT. Electric Utilities urged that if ADFIT is adjusted simply because it is a component of invested capital, then all of the other components of invested capital would also have to be included, and that is a far cry from both the limited, expedited nature of the proceeding envisioned by SB 1693, and from the interim TCOS process upon which SB 1693 is modeled. Electric Utilities submitted that the language in PURA §36.210 referring to invested capital as described in PURA §36.053 reinforces the concept that ADFIT is not to be included in calculating the DCRF adjustment.

Electric Utilities further replied that ADFIT is not kept on a FERC account basis, but rather is maintained at the FERC function level, and these functional amounts are then “allocated” to the individual FERC accounts. Electric Utilities noted that since some accounts that contain distribution-related investment also contain transmission-related investment, further allocation at the account level would be necessary. Electric Utilities pointed out that including

ADFIT changes in the DCRF formula would require an updated ADFIT allocation study and that having to prepare, and then possibly litigate, such an allocation study is contrary to the limited, expedited nature of the DCRF proceeding.

Electric Utilities disagreed with COH's argument that because SB 1693 envisions not only a positive but a negative DCRF adjustment, then ADFIT has to be included or there could never be a negative DCRF adjustment. Electric Utilities argued that a utility whose distribution-related depreciation expense exceeds its distribution investments could, if it chose, request a negative DCRF. Electric Utilities noted that because inclusion of ADFIT is not necessary in order for a utility to request a downward DCRF adjustment, COH's argument that ADFIT must be included thus fails. In sum, Electric Utilities replied that the proposed adjustment formula, consistent with the interim TCOS formula, properly excludes ADFIT.

Commission Response

The commission concludes that changes in distribution-related ADFIT should be included in the definition of net distribution invested capital, which the commission has included in the adopted rule as subsection (b)(4). PURA §36.210(a) provides that a DCRF is to be “based on changes in the parts of the utility’s [distribution] invested capital, as described in Section 36.053....” PURA §36.053 describes “original cost, less depreciation, of property used by and useful to the utility in providing service.” Thus, PURA §36.210(a) defines distribution invested capital narrowly, to include only original cost less depreciation, which is also referred to as distribution plant less accumulated depreciation or net distribution plant. In comparison, as indicated by §25.231(c)(2), the commission’s

long-standing practice has been to define invested capital to include additional items, including working capital, ADFIT, unamortized investment tax credits to the extent allowed by the Internal Revenue Code, insurance reserves, contributions in aid of construction, and customer deposits and other sources of cost-free capital. Some of these other types of invested capital serve to increase invested capital, while others serve to decrease invested capital.

Under PURA §36.210, changes in net distribution plant are the trigger for a DCRF. However, once triggered, the DCRF is not limited to recovery of net distribution plant. PURA §36.210(a) provides that a DCRF is to be *based* on changes in distribution invested capital; it does not require that the cost component of the DCRF be limited solely to distribution invested capital. Instead, it gives the commission discretion to determine which types of costs to include in the DCRF, with the limitation in PURA §36.210(e) that the DCRF not include indirect corporate costs or capitalized O&M expenses. If the DCRF were limited to recovery of net distribution plant, an electric utility would be limited solely to the recovery of depreciation expense through the DCRF; depreciation expense constitutes the recovery of distribution plant. In that case, the electric utility would be prohibited from recovering through the DCRF return on net distribution plant and taxes directly related to distribution plant. The proposed rule included return and plant-related taxes, and the inclusion of these items substantially increases the DCRF and thereby greatly benefits an electric utility that implements a DCRF. Changes in ADFIT are largely driven by changes in plant investment, depreciation expense, and federal income taxes, all of which are to be updated in a DCRF application.

The commission first adopted the interim TCOS “factor” (ITF) in 1999, and it is the first type of plant-related cost recovery factor adopted by the commission. For an electric utility that is eligible for a DCRF pursuant to PURA §36.210, distribution plant is typically around double the level of its transmission plant. This means that inclusion of ADFIT in the calculation of the DCRF will have a much greater impact on the electric utility’s resulting revenues than would inclusion of ADFIT in the calculation of an ITF. Thus, the ITF rule’s exclusion of ADFIT is distinguishable from the adopted DCRF rule’s inclusion of ADFIT. More recently, in 2007, the commission adopted a rule for a transmission cost recovery factor for certain non-ERCOT utilities (non-ERCOT TCRF). The non-ERCOT TCRF rule requires inclusion of ADFIT. *See* §25.239(e) (relating to Transmission Cost Recovery Factor for Certain Electric Utilities) (definition of “Revreq”).

Concerning Project Number 38298, where the commission considered adopting a DCRF before the enactment of PURA §36.210, only one commenter raised the issue of inclusion of ADFIT in the calculation of the DCRF: “[Oncor] Cities stated that the rule does not explicitly require the utility to update the accumulated deferred federal income tax (ADFIT) balance, which is necessary to arrive at an appropriate update to invested capital. Cities stated that if a utility fails to make the appropriate changes to ADFIT, the rule provides no remedy for the commission or intervenors. Cities also commented that the rule should take into account consolidated tax savings, changes in depreciation rates, and a reduction in the return on invested capital to reflect the sharp decrease in regulatory risk

affecting the utility's required cost of capital." *Rulemaking Related to Cost Recovery by Electric Utilities of Distribution Costs*, Project Number 38298, staff's recommended Order Adopting §25.243 for Consideration at the December 16, 2010 Open Meeting at 78. Staff's recommended response stated: "[T]he commission agrees with Oncor that inclusion in the DCRF of issues such as ADFIT, depreciation rates, and rate of return would undermine the DCRF mechanism's purpose, which is to allow for updates to rate base to reflect increases in distribution investment without the electric utility having to file a base-rate proceeding." *Id.* at 82-83. Thus, in the prior DCRF rulemaking, ADFIT was only briefly raised along with various other issues. In contrast, in the current rulemaking, there were extensive, persuasive comments filed that advocated inclusion of ADFIT in the calculation of the DCRF. The commission concludes that ADFIT can be included in the calculation of the DCRF without unduly broadening the scope of a DCRF proceeding.

Finally, the commission concurs with Oncor Cities and TIEC that the effects of FIN 48 should be excluded from the DCRF mechanism, consistent with commission precedent. *Application of Oncor Electric Delivery Company for Authority to Change Rates*, Docket Number 35717, Order on Rehearing at 18, finding of fact 60.

Proposed §25.243(b)(3): Indirect Corporate Costs

Representative Turner commented on an amendment to SB 1693 that he sponsored. Representative Turner commented that his amendment prohibiting indirect corporate costs (and capitalized O&M expenses) from being recovered through the periodic rate adjustment mechanism was an important safeguard for Texas ratepayers. Representative Turner also stated

that he is concerned that the proposed rule substantially weakens this protection and does not reflect his intent, which included no exceptions to the prohibition. Representative Turner observed that the proposed rule permits a wide variety of allocated, indirect costs that go well beyond the “wires-and-poles” focus of the legislation.

COH, Oncor Cities, State Agencies, CORE, and OPC all commented that the proposed rule inappropriately appears to create an exception to the prohibition against inclusion of indirect corporate costs by allowing costs recorded as “construction overhead in accordance with FERC guidelines.” These parties all pointed out that PURA §36.210(e) specifically prohibits inclusion of any indirect corporate costs, without limitation or exception. Oncor Cities cited officers' salaries, executive compensation, office supplies and furniture for the corporate headquarters, and Board of Directors' expenses as examples of administrative and general expenses that should be excluded from recovery through the DCRF. Oncor Cities contended that the reference to the FERC guidelines provides a significant, additional means for utilities to circumvent the statutory exclusion of indirect corporate costs, and the FERC guidelines with respect to construction overhead provide considerable discretion to the utility. In support of this contention, Oncor Cities pointed to FERC Chart of Accounts Instruction 3(A)(12), which permits capitalized general administration expenses like pay and expenses of the general officers and general and administrative expenses within the components of construction if they are “reasonably applicable” to the utility's construction program and further spread an “equitable proportion of such costs” to each construction project. Oncor Cities expressed concern that applying an exception based on the FERC guidelines will result in the inclusion of indirect corporate costs in contradiction of the law.

Oncor Cities maintained that the Legislature intended to allow only the direct costs of new distribution investment, and not to pass through general corporate administrative costs outside of a general rate case. Oncor Cities expressed concerns regarding administrative and general (A&G) costs associated with the parent company's service company that may be allocated to transmission-distribution construction because affiliate transaction standards are applicable to these expenses issues which require greater scrutiny than is likely to be available in an expedited proceeding.

Oncor Cities commented that indirect corporate costs, by their nature, are fixed costs that will be incurred regardless of the incremental distribution invested capital and that if the new distribution capital investment had not been undertaken, the indirect corporate costs assigned to the distribution plant construction would be reallocated to the utility's other functions or construction activities. Oncor Cities pointed out that the assignment of indirect corporate costs to new distribution investment may reduce the costs allocated to other functions; however, only the increased amount assigned to distribution investment will be recovered from customers between rate cases. State Agencies made a related argument that the statutory language was intended to preclude double recovery of general corporate costs of a central service entity that were already included in base rates.

COH observed that the prohibition in the enabling statute represents an important consumer protection that should not be diluted or rendered impotent and urged that where the Legislature has supplied specific words, they should be reflected without exception in the final rule. COH

pointed out that exclusion of indirect corporate costs does not deny the utility the right to recover these costs during any base rate proceeding, and does not prejudice the utility. COH argued that this protection was enacted by the Legislature to restrict a utility from utilizing a flexible interpretation of accounting rules to maximize accelerated cost recovery beyond that intended by the Legislature. COH further asserted that the Legislature recognized that certain rate issue components (such as pension and legal expenses) are subject to variable interpretation and have only an indirect impact on capital additions for ratemaking purposes and should be litigated individually in a comprehensive rate proceeding rather than within a DCRF proceeding. COH commented that only those direct costs associated with new invested capital are properly included in DCRF adjustments.

Oncor Cities urged the commission to reject the proposed rule's exception to the definition of indirect corporate costs, but to the extent that the exception for construction overhead costs is included in the definition of indirect corporate costs, argued that the exception should be strictly limited to administrative costs that are directly incurred in constructing the distribution project and exclude salaries of officers with general responsibility for construction activities and allocations of general costs across construction projects.

COH urged the commission to delete the definition of “indirect corporate costs” and pointed out that the Legislature was undoubtedly aware of the varying corporate structures utilized by utilities subject to the new law. COH argued that with this knowledge, the Legislature still opted for the all-encompassing language and that this language should be respected. OPC argued that the phrase “costs recorded as construction overhead in accordance with FERC guidelines” is

unduly vague and fails to put the reader on notice as to what is contemplated by “FERC guidelines” in the definition. OPC claimed that FERC has many regulations and advisory statements that arguably could be relevant to this definition. OPC commented that the definition of “indirect corporate costs” in the proposed rule does not provide adequate clarity or specificity as to what this term means. OPC contended that the lack of clarity will undoubtedly result in uncertainty, disagreement, and unnecessary additional litigation in the DCRF proceedings. OPC also claimed that the proposed definition contains no explanation or specific reference for the descriptor “corporate support costs.” OPC recommended that the commission revise the definition of “indirect corporate costs” to provide greatly needed clarity and certainty and provided suggested wording.

COH agreed with OPC's comments that the proposed rule is unduly vague, but noted that it cannot support OPC's suggested language. COH commented that Generally Accepted Accounting Principles (GAAP) are open to varying interpretations of what should be included in capital expenditures as utilities themselves have recognized, and OPC's suggested changes would not adequately remedy the ambiguity.

Electric Utilities commented that OPC's proposed definition is reasonable with some minor modification for additional clarity, and that both the State Agencies and the Oncor Cities ignore the statutory language that excludes only indirect corporate cost, not all corporate costs. Electric Utilities argued that because the Legislature excluded only indirect corporate costs, it necessarily intended that direct corporate costs be allowed. Electric Utilities commented that the FERC Uniform System of Accounts prescribes how costs are to be recorded for costs associated

with the construction of electric plant and that such instructions specifically direct that overhead costs be included in the capitalization of constructed plant.

Electric Utilities observed that the legislative history indicates that the expenses that were intended to be excluded were not what the Oncor Cities and the State Agencies suggest be excluded—a broad swath of corporate support costs that are properly allocable and assignable—but rather the only costs that should be excluded are those that would be excluded anyway from distribution investments in a rate proceeding. Electric Utilities argued that there is no evidence that the Legislature intended by this term in SB 1693 to exclude any cost that the utility would otherwise be allowed to recover as distribution invested capital in a comprehensive base-rate proceeding. Electric Utilities further argued that it is only those costs not directly related to the planning, design, or construction of distribution facilities—things such as “corporate aircraft and artwork”—that were intended to be excluded by this term.

Electric Utilities further commented that the definitions offered by these parties would draw an unnecessary and inequitable distinction between those companies that use a shared service company or parent in their operations and those that have everything in-house. In response to State Agencies’ suggestion that there is a concern that there will be double-recovery of costs, Electric Utilities stated that regardless of whether the person working on a distribution project is in-house or in a separate affiliated company, or in a totally independent third party, that person's time is being capitalized on projects rather than expensed and that there is no danger of double recovery. Electric Utilities stated that Oncor Cities' concern about affiliate transactions does not justify the significant exclusions from distribution invested capital for those companies

that happened to be structured with a separate service company. Electric Utilities noted that more importantly, PURA resolves any concern about affiliate transactions in a process like this by providing that the affiliate issues may be addressed when the rates are finally reconciled.

Commission Response

PURA §36.210(a) allows recovery of the parts of a utility's invested capital that are "categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks in accordance with commission rules adopted after consideration of the uniform system of accounts prescribed by the Federal Energy Regulatory Commission." Thus, this provision starts with the FERC uniform system of accounts (USOA) as the benchmark and gives the commission the discretion to deviate from that benchmark. However, the commission's discretion is circumscribed by PURA §36.210(a), which prohibits inclusion of indirect corporate costs (and capitalized O&M expenses). The comments focused on what constitutes an "indirect" cost, but did not address what constitutes a "corporate cost" or "corporate support cost," neither of which have a generally understood definition. After reviewing PURA §36.210, the commission concludes that the purpose of this section's exclusion of indirect corporate costs is to circumscribe the commission's discretion in expanding the definition of distribution invested capital beyond the well-established standards in the FERC USOA. As a result, PURA §36.210 prohibits the commission from categorizing as distribution invested capital corporate aircraft and artwork or other invested capital that arguably is indirectly necessary to provide distribution service.

The interpretation of indirect corporate costs advocated by the consumer commenters would require a utility to dramatically alter its accounting practices used to identify capital costs, even though these accounting practices comply with the FERC USOA and have been followed by electric utilities for decades without challenge by consumer groups.

The proposed rule's definition of "indirect corporate costs" confused rather than clarified the issue of what costs are properly includable as distribution invested capital. The definition of distribution invested capital in the adopted rule excludes indirect corporate costs without the need to define that term. Therefore, the adopted rule does not contain a definition of indirect corporate costs.

Concerning distribution invested capital that includes payments to affiliates, the commission has changed subsections (b)(2), (e)(1), (e)(5), and (f) to expressly address compliance with PURA §36.058.

Proposed §25.243(b)(4): Weather-normalized

Electric Utilities submitted that weather normalization should be based on the weather-normalization model, including the number of years of data, used to design base rates in the electric utility's last comprehensive base-rate proceeding. Electric Utilities noted that the weather adjustments in the current earnings monitoring reports (EMR) are based on the same number of years as was used in the utility's last comprehensive base-rate proceeding, and that for consistency purposes and in order to avoid confusion, the number of years used to define the "normal" period in the DCRF and EMR processes should be the same number of

years used in the last comprehensive base-rate proceeding. Electric Utilities argued that it should only be in those cases where the commission has decided the electric utility's last comprehensive base-rate proceeding in such a manner that it cannot be determined what time period was used that the 10-year period should be used as the default.

Electric Utilities asserted that the inconsistent use of weather data can result in an anomalous growth factor determination and provided an illustration of this point. Electric Utilities proposed that if the rule requires the use of the most recent ten years, it should also clarify how that should be accommodated with regard to historical billing determinants used in the formula. Electric Utilities commented that the only readily apparent way to adjust for this problem would be to require the utility to restate the billing determinants from the utility's last comprehensive base-rate proceeding by recalculating weather normalization using ten years of data. Electric Utilities pointed out that this could foster disputes that would not occur if consistent weather data were used. Electric Utilities commented that the typical practice has been to use calendar years for purposes of weather normalization, and that this should be clarified in the rule.

REP Coalition commented that Electric Utilities correctly pointed out that the lack of consistency in the weather normalization methodology between the utility's last comprehensive base-rate proceeding and a DCRF application could lead to erroneous changes in billing determinants. REP Coalition agreed with Electric Utilities' recommendation to change proposed subsection (b)(4) to ensure consistency between the weather normalization

methodology used for determining historical billing determinants and current billing determinants.

OPC commented that the challenge in requiring a specific normalization period for all utilities at this time is that, for some utilities, a different normalization period was used when normalizing the billing determinants used to set base rates. OPC concurred with Electric Utilities' proposed definition of weather-normalized, which would synchronize the duration of the normalization periods used in the base rate and DCRF proceedings when possible and use a 10-year period as a default when not possible. As a result, according to OPC, for some utilities the change in billing determinants computed for purposes of a DCRF would capture load growth without any additional "noise." OPC further reasoned that in the case of a utility for which the 10-year default period must be used, Electric Utilities' definition would encourage parties in the utility's next base rate case to either stipulate to a weather normalization methodology or obtain an order specifying the methodology. OPC proposed that the long-term result is that for all utilities, the normalization period for the billing determinants used to set base rates and those used to set the DCRF can be synchronized.

Oncor Cities agreed with the proposed rule's requirement regarding the determination of normal weather. Oncor Cities opposed Electric Utilities' proposed change, which would allow the use of varying normal weather periods with accompanying divergent accuracies in forecasting the average weather in the future. Oncor Cities noted that the commission has previously adopted the most recent ten years of data to determine normal weather for purposes of developing demand growth rates in energy efficiency filings and that maintaining

consistency with the normal weather standard adopted for the energy programs efficiency is reasonable and promotes a uniform approach to normalizing weather.

Oncor Cities commented that there is no inherent advantage in maintaining the same weather normalization period from the utility's previous rate case and that the only purpose of weather normalization is to develop an accurate description of future billing determinants assuming average weather conditions. Oncor Cities expressed concern that weather normalization based on a historical period of excessive length will unjustly enrich the utilities. Oncor Cities pointed out that in some cases, previous weather normalizations were based on 20-30 year periods and, given climate trends of hotter weather, a shorter historical period will be less likely to over-compensate the utility. Oncor Cities commented that contrary to Electric Utilities' arguments, there is no reason to re-adjust the previous rate case billing determinants for the same ten-year normal weather. Oncor Cities urged that the weather-normalized billing determinants for future DCRF charges should be the most reasonable estimate of average weather, regardless of the normal weather periods used in previous normalization models.

Oncor Cities commented that a systematic warming trend is evident in recent years and that data from recent weather normalization results in Texas demonstrates that the most recent ten years is warmer than the prior 10 and 20 year periods. Oncor Cities argued that the warming trend is consistent with the predominant scientific acceptance of climate change and that even if the recent warming trend is due to long-term cyclical conditions rather than global warming, use of the shorter 10-year period is prudent.

Commission Response

The commission disagrees that weather normalization should be based on the weather-normalization model used to design base rates in the electric utility's last comprehensive base-rate proceeding. Both the Electric Utilities and OPC allude to statistical differences that could occur from the use of weather normalization periods that differ between the base-rate and DCRF proceedings. However, requiring the use of the same duration would still result in the use of different time periods, because the DCRF period will use weather data from years after the base-rate proceeding, regardless of the duration of the data. The use of larger sample sizes in the development of inferential statistics is generally more representative than smaller sizes, but only when statistical data points are randomly distributed. As Oncor Cities point out, weather data are not randomly distributed by year. There can be weather trends, and the commission concludes that the use of ten years of data is a reasonable means of capturing such trends.

The commission agrees with the Electric Utilities that the term "calendar" should be inserted in the language of the rule to be consistent with the historical practice of using calendar years for the purposes of weather normalization.

*Section 25.243(c)(1): Application for DCRF or DCRF Update—General Requirements**City Jurisdiction*

CORE, COH, CEP and Oncor Cities commented that the proposed rule includes provisions that pose significant jurisdictional issues. These parties stated that the Legislature expressly took care not to infringe upon the exclusive original jurisdiction of municipalities beyond permitting a

periodic rate adjustment mechanism to be implemented by the commission. Oncor Cities commented that the maintenance of municipal jurisdiction was a central component of the negotiated process that led to the passage of SB 1693. Oncor Cities stated that they and other stakeholders worked diligently to arrive at legislation that accommodated parties' critical concerns such as the jurisdiction granted to them by PURA, and legislators responded by providing assurance that municipal jurisdiction would not be curtailed by SB 1693. CORE, COH, CEP, and Oncor Cities argued that express provisions in the proposed new rule would limit the original jurisdiction of the municipalities and must be deleted from the proposed rule so that, at a minimum, the rule does not violate PURA and is consistent with the intent of SB 1693.

CEP commented that the fourth through seventh sentences of this subsection should be removed in the final rule. According to CEP, these sentences address directly, and would interfere with, the original jurisdiction of municipalities. CEP and COH stated that the provisions of SB 1963 address directly the preservation of original jurisdiction of the municipalities, and PURA §36.210(f) provides that "Nothing in this section is intended to ... limit the jurisdiction of a municipality over the rates, operations and services of an electric utility as provided by Section 33.001...." CEP stated that the provisions that speak to the timing of a municipal action, and the results of a municipal decision, and direction to the utility regardless of the municipal decision, would interfere with and impinge on the municipality's original jurisdiction in direct contravention of the above-cited section of SB 1963. CEP noted that, specifically, the fourth sentence requiring simultaneous filing with all regulatory authorities would infringe on that jurisdiction, and would discourage the utility from working with its municipalities. CEP similarly noted that the fifth through seventh sentences also would encroach on municipal jurisdiction by directing how and when the

municipality must act, and the actions of the utility after the rule-imposed determination of municipal action, and thus the impact of the proposed rule would constitute direct interference with the original jurisdiction of municipalities, which would violate the plain language of SB 1963. CEP commented that the commission should delete those four sentences upon final adoption of the rule. CORE supported CEP's recommendations.

COH commented that subsection (c)(1) of the proposed rule would require a municipality's governing body with original jurisdiction to make a final decision on the DCRF application within 60 days after the application is filed. COH submitted that the 60 day restriction for final action by a municipality would effectively impair municipal regulation and would not provide the necessary opportunity for proper review, discovery, analysis, potential negotiations and final action. COH remarked that a municipality must have time for discovery and analysis of responses to discovery, development of potential issues, and review of potential issues by the city council in order to adequately exercise its original jurisdiction. COH maintained that inherent in the meaningful exercise of a city's local jurisdiction is the ability to render a final, non-appealable decision, and that as proposed, subsection (c)(1) requires an electric utility to appeal a local ruling on its DCRF application, without regard to the outcome of the city's ruling. COH stated that as a practical matter, this provision effectively prevents the settlement of a DCRF application at the local level and guarantees the addition of a city as a party to the commission's DCRF proceeding, even if the city grants the application. COH stated that this undeniably contradicts §36.210(f), because it limits a city's jurisdiction to grant the very application that §36.210 authorizes.

In order to allow a municipality adequate opportunity for retention of experts, review of a DCRF filing, discovery, negotiations, and final action, COH recommended a minimum of 90 days for local action. COH further commented that experience has shown in similar filings that the option to extend the local timeline for negotiations can result in ultimate resolution of the filing at the local level, as PURA §36.210 clearly contemplates. COH recommended that the proposed rule include a local option to extend the 90-day local timeline by agreement for negotiations in progress and that changes to the proposed rule explicitly allow negotiated settlement at the local level.

CORE commented that the general requirements for the filing of an application for a DCRF filing would provide an unworkable time frame for the processing of the application that would also infringe upon the rights of municipalities exercising exclusive original jurisdiction, in violation of PURA §§32.002(2), 33.001(a), and 36.210. CORE further commented that the limited time for a municipality to exercise its exclusive original jurisdiction over a DCRF filing is not authorized by SB 1693 and would directly violate PURA §36.108(a)(1), which guarantees local regulatory authorities up to 125 days to exercise their exclusive original jurisdiction over rate change requests. Oncor Cities and COH agreed.

CORE stated that proposed §25.243(c)(1) would require the utility to simultaneously file applications with all regulatory authorities with original jurisdiction (i.e., both the local regulatory authorities and the commission), and would require a municipality to issue a final decision on the requested rate within 60 days or else the rate change would be deemed denied and appealable to the commission. As a result, the proposed rule would effectively eliminate any meaningful exercise of

jurisdiction by the municipality, requiring the municipality to almost immediately deny an application for a DCRF filing. CORE noted that because subsection (c)(1) also requires all appeals of final decisions from local regulatory authorities to be consolidated with applications before the commission, and requires system-wide rates, the DCRF applicable to areas within the municipality (over which the municipality has exclusive jurisdiction) would be conformed to the commission's final order for rates affecting areas in which it has original jurisdiction, thereby reducing a municipality's original jurisdiction to a meaningless exercise. CORE submitted that a better balance must be struck between an expedited schedule and municipalities' rights under PURA. CORE specifically remarked that additional days must be added to the timeline for processing a DCRF filing to allow a municipality to meaningfully, yet expeditiously, exercise its exclusive original jurisdiction. Further, CORE noted, the rules must not dictate a certain number of days a municipality has to exercise its original jurisdiction, in direct violation of PURA §36.108.

CORE stated that, moreover, the proposed deadline violates the express provisions of PURA §36.108(1)(a), in which, when read with §36.102, the local regulatory authority is guaranteed at least 125 days of exclusive original jurisdiction over rate-change requests within its municipal boundaries. CORE argued that potential arguments that PURA §36.108 is not applicable to DCRF filings because it is located in Subchapter C of PURA Chapter 36, while future §36.210 is located in Subchapter E of PURA Chapter 36, lack merit. CORE argued that Subchapter C of PURA pertains to "General Procedures for Rate Changes Proposed by a Utility," and a DCRF filing clearly meets the definition of a "rate change proposed by a utility." Further, nothing in Subchapter C, or specifically in §36.108(1)(a), limits the applicability of the 90-day suspension period to rate changes implemented under Subchapter C, and nothing in §36.102(a) limits the

requirement for a utility to file a statement of intent with a local regulatory at least 35 days prior to the 90 days rate suspension period being triggered. CORE also argued that nothing in Subchapter E, or specifically in §36.210, exempts the suspension period authorized by §36.108 from applying to rate changes made through a DCRF filing. CORE stated that SB 1693 does not specify a time frame for a municipality to exercise its exclusive original jurisdiction over an application for a DCRF filing; rather, SB 1693 expressly states that it is not the Legislature's intent to limit a municipality's right to exercise its exclusive original jurisdiction in authorizing the commission to implement a periodic rate adjustment mechanism.

Similarly, Oncor Cities stated that PURA §36.210 makes clear that nothing within it abrogates the original, exclusive jurisdiction of cities over utility rates within their boundaries, and proposed subsection (c)(1) imposes a limit on the jurisdiction of cities that is found nowhere within the statute. Oncor Cities argued that proposed subsection (c)(1) contradicts this exclusive, original municipal jurisdiction by purporting to establish a new timeline by which cities must exercise jurisdiction. Oncor Cities commented that PURA §36.102 and §36.108 together permit cities to take action on a utility's rate change application up until the effective date of the rate change, subject to the ability of a city to suspend the effective date of the rate change by 90 days, and this arrangement is jurisdictional, not capable of being modified by administrative rule. By imposing a shorter deadline for city action than that established by statute, the proposed rule would have the effect of denying the full exercise of exclusive, original jurisdiction permitted cities by PURA, jurisdiction explicitly reaffirmed and protected by PURA §36.210.

State Agencies commented that nothing in PURA §36.210 mandates a 60-day *maximum* period of time for the city to review and act upon a utility's DCRF application, or supports a default denial after that point, and that the 60-day floor in PURA §36.210(a)(1)(C) had been converted by this rule into a ceiling for city action. State Agencies argued that, while the Legislature provided for an expedited proceeding, that standard could be met by allowing more than 60 days for the municipal regulatory authority to act on the DCRF request.

REP Coalition commented that by itself the issue of whether the local regulatory authority has 60 days to review a DCRF application, or as much time as the city groups maintain is necessary, does not intrude on REP Coalition's core issues of adequate notice of new rates, system-wide rates, and effective date. REP Coalition stated that system-wide rates and at least 45-days' advance notice of any DCRF change can be accomplished regardless of whether the cities are provided 60 days to act or 120 days to act; additionally, the imposition of an effective date of September 1 — which is consistent with the statutory requirement in PURA §36.210(b)(2) that a utility shall implement, to the extent possible, all nonfuel rates to be adjusted in a 12-month period that are charged by the utility to retail electric providers — can be accomplished regardless of the time frame allocated to the cities. REP Coalition noted, however, that some of the parties who propose elimination of or changes to the time by which a local regulatory authority is required to act on a DCRF application fail to demonstrate how system-wide rates could be approved 46 days before September 1 under their proposed timelines. REP Coalition expressed the belief that there is more than one viable timeline, including the timeline included in the proposed rule. REP Coalition commented that it takes no position on the Oncor Cities'

timeline issue so long as the timeline in the final rule does not affect the system-wide rates, the 45-day notice period, or the target effective date of September 1.

REP Coalition commented that system-wide rates are essential to REP billing systems and retail product design and without system-wide application of an electric utility's DCRF, the costs of billing retail electric service will increase, because both transmission and distribution utilities (TDUs) and REPs would have to extensively test billing systems to ensure that customers across various local jurisdictions are being charged the appropriate DCRF rate. REP Coalition also stated that system-wide utility rates are essential to reduce the complexity of the shopping experience for retail electricity customers.

Electric Utilities commented that the Legislature had given the commission explicit authority under PURA §36.210(a)(1) and (g) to adopt rules accelerating the time periods that would otherwise be applicable in rate cases. Electric Utilities stated that PURA §36.210(a)(1) requires that a DCRF application be approved or denied in accordance with an "expedited procedure," and PURA §36.210(g) directs the commission to adopt rules providing for filing requirements "consistent with the expedited procedure." Electric Utilities stated that the term "expedited" means "to accelerate the process or progress of," and that the Legislature has given the commission explicit authority to adopt rules accelerating the time periods that would otherwise be applicable in rate cases.

Electric Utilities contended that the city groups' insistence on a 125-day time period to review a DCRF application leads to an absurd result, because PURA §36.210(b)(2) mandates that retail

electric providers be given at least 45 days' notice of the rates approved under a DCRF application. Electric Utilities submitted that if municipalities were given 125 days to review a DCRF application before the commission obtained jurisdiction over the appeal, the commission would have only 15 days to consider the application and issue an order even under the 185-day time limit for full-blown base-rate cases. Shortening the 185-day limit by 15 days, which can hardly be said to be expedited at all, would give the commission no time whatsoever to review the DCRF application. Electric Utilities replied that this is obviously an illogical and absurd result, particularly because the statute requires the DCRF rate to be applied on a system-wide basis. Because the Legislature is never presumed to have intended a foolish or absurd result, the city groups' statutory interpretation is wrong. Electric Utilities continued that it is possible to harmonize PURA §36.210(a)(1) and PURA §36.108 in a manner that does not lead to an absurd result, because PURA §36.108(a)(1) provides that a municipality may suspend a rate change "for not longer than 90 days" after the date on which the rate change would otherwise be effective. Thus, while 90 days is the maximum amount of time a municipality can suspend a rate change beyond the date it would otherwise be effective, the commission has the implied power to shorten that time period when necessary to implement other parts of PURA, and that in this instance, it is necessary for the commission to shorten the time period set forth in PURA §36.108(a)(1) to implement the "expedited procedure" mandated by PURA §36.210(a)(1). Electric Utilities commented that on the other hand, if provisions of PURA §36.210(a)(1) and PURA §36.108 are deemed to be in irreconcilable conflict and therefore cannot be harmonized, PURA §36.210 prevails because it was enacted more recently than PURA §36.108 and because it is specific to DCRF applications, whereas PURA §36.108 applies to rate cases generally. Electric Utilities replied that COH implicitly concedes that the 125-day period is not

jurisdictional by proposing that municipalities be given 90 days, rather than 125 days, to act on a utility's DCRF application.

Electric Utilities also contended that the city groups' argument is inconsistent with the legislative history of PURA §36.210, given that the very purpose of the statute, as expressed in bill analyses for the Senate and House, is to encourage original jurisdiction municipalities "to modernize and bring efficiencies to their electric utility rate regulation processes through the use of periodic rate adjustments." Electric Utilities commented that requiring utilities to submit to the 125-day period used for comprehensive base-rate cases would create no efficiencies in municipalities' electric utility rate regulation process and therefore would run afoul of the intent of the statute. Electric Utilities stated that the city groups' argued that the proposed 60-day limit is inconsistent with PURA because the Legislature expressly provided in PURA §36.210(f)(2) that nothing in the legislation is intended to "affect the limitation on the commission's jurisdiction under Section 32.002," and because §36.210(f)(4) states that nothing in PURA §36.210 is intended to "limit the jurisdiction of a municipality over rates, operations and services of an electric utility as provided" by PURA §33.001. Electric Utilities argued, however, that the city groups have omitted key language in both statutes, because PURA §32.002 provides that the subtitle of PURA addressing electric utilities does not authorize the commission to affect the jurisdiction of a municipality exercising original jurisdiction "[e]xcept as otherwise provided by this title." Similarly, PURA §33.001 grants a municipality original jurisdiction over the rates, operations, and services of electric utility "subject to the limitations imposed by this title." Thus, PURA §32.002 and §33.001 both contemplate that a municipality's jurisdiction can be limited by the

commission pursuant to other portions of PURA. Electric Utilities stated that the proposed 60-day time period in subsection (c)(1) should be adopted.

Commission Response

CORE and Oncor Cities argued that PURA Chapter 36, Subchapter C applies to a DCRF application. CORE argued that Subchapter C applies to a rate change proposed by a utility, and a DCRF application is a rate change proposed by a utility; therefore, a DCRF application is subject to Subchapter C. The commission disagrees. Although a DCRF application pursuant to PURA §36.210 is not expressly exempted from PURA Chapter 36, Subchapter C, the Legislature impliedly intended such an exclusion. PURA §36.210 is in Subchapter E, not Subchapter C. The lower numbered cost recovery sections in Subchapter E expressly exempt the sections from Subchapter C, while the higher numbered ones do not expressly address the issue. *Compare* PURA §36.202(d) and §36.203(f) to PURA §§36.204-36.209.

The PURA provision that authorizes the interim TCOS factor is located outside of Subchapter C. *See* PURA §35.004(d). Even though that provision is not expressly exempted from Subchapter C, the commission's rule that implements the provision does not subject applications pursuant to that rule to Subchapter C. The original ITF rule was adopted by the commission in 1999 and since then the commission has approved numerous applications pursuant to that rule, without any challenge that Subchapter C applies. *See Rulemaking Proceeding to Amend SUBST. R. §25.192(g), Project Number 37519, Order Adopting Amendment to §25.192 as Approved at the July 30, 2010 Open Meeting (comments filed by*

CORE and Oncor Cities did not challenge commission authority to adopt an expedited procedural schedule for an ITF application).

Similar to ITF applications, ERCOT TCRF applications, which are also authorized under PURA §35.004(d), are not processed in compliance with Subchapter C. In addition, the commission adopted the non-ERCOT TCRF rule in 2007 without including provisions applying Subchapter C to that rule. *See Rulemaking Relating to Transmission Cost-Recovery Factor for Non-ERCOT Utilities*, Project Number 33253, Order Adopting New §25.239 as Approved at the December 7, 2007, Open Meeting at 30 (AXM and CARD, which are participating as part of CORE in the current rulemaking, stated that PURA §36.209 does not limit the time the commission has to conduct a non-ERCOT TCRF proceeding).

Although the ITP, ERCOT TCRF, and non-ERCOT TCRF PURA sections do not give cities jurisdiction over an application filed pursuant to one of those sections, such an application is nevertheless a rate change proposed by a utility. Therefore, under CORE's reasoning, an application under any of these sections should be subject to Subchapter C, just like a base-rate application over which the commission has original jurisdiction is subject to Subchapter C.

The commission concludes that a DCRF application is impliedly not subject to Subchapter C. Subsection (a)(1) of PURA §36.210 requires that a DCRF be approved or denied in accordance with an expedited procedure that extends for not less than 60 days. Subsection (a)(5) requires that a DCRF be applied by an electric utility on a system-wide basis.

Subsection (b) requires that an electric utility provide notice to retail electric providers (REPs) of the approved DCRF not later than the 45th day before the date the DCRF takes effect. Subsection (g) requires that the commission adopt rules necessary to implement the section. In addition, subsection (g) requires that the commission's rules provide for a procedure by which a DCRF tariff or rate schedule is to be reviewed and approved, and provide for filing requirements consistent with the expedited procedure described in subsection (a)(1). In summary, the commission is required to adopt a DCRF rule that imposes filing requirements, mandates an expedited procedure, specifies the manner in which a DCRF is reviewed and approved, ensures that REPs receive at least 45 days' notice of the approved DCRF, and ensures that the DCRF is applied on a system-wide basis. These statutory requirements cannot be met without the commission establishing parameters for a city's consideration of a DCRF.

If a DCRF application were subject to Subchapter C, an electric utility applying for a DCRF would have to file its application at least 35 days before its proposed effective date, pursuant to PURA §36.102(a). Pursuant to PURA §36.108(a)(1), a city could suspend the proposed effective date for 90 days, meaning that the city would have 125 days to act on the application. The utility would have to appeal the city's final decision to the commission in order to ensure that the DCRF is applied on a system-wide basis. A DCRF is a rate and applying it on a system-wide basis means that the same DCRF must apply to all parts of the utility's system. As explained by the REP Coalition, requiring that a DCRF be implemented on a system-wide basis is essential to promotion of a competitive retail electric market in Texas, consistent with PURA §39.001(a) and (b).

If the commission had no authority to establish parameters for the city's DCRF proceeding, then PURA §33.051 and §33.053(b) would presumably apply, and the utility would have 30 days to appeal the city's final decision on the application. Adding that time to a 125-day review period by the city means that appeal of the city's final decision to the commission could occur 155 days after the utility filed its DCRF application. Assuming that the commission made its final decision on the appeal 14 days after the appeal was made and assuming that on the day following the commission's final decision the utility provided 45 days' notice to the REPs of the approved DCRF, the DCRF would take effect 215 days after the DCRF application filed—30 days more than can be used for a base-rate proceeding (except in the unusual case where the effective date in a base-rate proceeding is extended pursuant to PURA §36.108(a)(b)). Without establishing parameters for the city's DCRF review timeline, the commission could not comply with PURA §36.210's requirement that the commission adopt a DCRF rule that mandates an expedited procedure.

A commission DCRF rule that establishes parameters for cities' DCRF review timeline does not violate subsection (f)(2) and (4) of PURA §36.210. Subsection (f)(2) states that nothing in PURA §36.210 is intended to affect the limitation on the commission's jurisdiction under PURA §32.002. That section provides that the commission is not authorized to affect a city's jurisdiction, *except as otherwise provided by PURA*. Subsection (f)(4) of PURA §36.210 states that nothing in PURA §36.210 is intended to limit the jurisdiction of a city over the rates, operations, and services of an electric utility as provided by PURA §33.001. That section provides that a city has exclusive original jurisdiction in the city *subject to the limitations*

imposed by PURA. Both PURA §32.002 and §33.001 are expressly subject to limitations in other parts of PURA, including PURA §36.210. Reading those two sections in conjunction with PURA §36.210, the commission concludes that it has the authority to affect a city's jurisdiction to the extent necessary to fulfill its obligations under PURA §36.210. Establishing parameters for a city's DCRF review timeline is necessary to comply with PURA §36.210's requirement that the commission adopt a DCRF rule that mandates an expedited procedure of at least 60 days. Subsection (c)(1) of the rule gives a city 60 days to review a DCRF application—a meaningful and reasonable period of time given that DCRF proceedings are expedited.

Coordination of City Proceedings with Commission Proceeding

CORE commented that the provision in the proposed rule that states that denial of an application for a DCRF filing by a local regulatory authority shall automatically be suspended is not logical and, more important, is contrary to PURA §36.111. CORE stated that if the effective date of the proposed rates is not until the 46th day *after* a final order is issued by the commission, the suspension of a local regulatory authority's denial does not serve a purpose. Moreover, under PURA §36.111, rates established by a regulatory authority must be observed until changed on appeal, prohibiting the suspension of the local regulatory authority's decision. State Agencies commented that the “deemed” denial, after expiration of a 60-day time period for a municipal authority to act, is not supported by the statute. Electric Utilities stated that to ensure that the commission would not be delayed by waiting for the appeals from municipal actions, the rule should provide for automatic appeals upon expiration of the 60-day time-period for municipal review. REP Coalition supported Electric Utilities' proposed change to subsection (c)(1) to make

automatic the appeal of a municipality's governing body's decision on a DCRF application, noting that an automatic appeal would reduce the potential for unnecessary delay in processing a DCRF application.

Commission Response

As explained above, PURA Chapter 36, Subchapter C, including PURA §36.111, does not apply to a DCRF proceeding. Also as explained above, a DCRF must be applied on a system-wide basis, and automatic suspension of the city's final decision is necessary to ensure a system-wide DCRF. Likewise, deeming a DCRF application denied if the city does not make a final decision within 60 days is necessary for an expedited DCRF procedure. The commission agrees with Electric Utilities and REP Coalition that the rule should make an electric utility's appeal automatic; doing so avoids the cost of actually appealing the city action or inaction and ensures that the appeal is made. Because an appeal is necessary to ensure a system-wide DCRF, making the appeal automatic helps ensure a system-wide DCRF. The commission has made corresponding changes to subsection (c)(1). Because the commission has made an appeal automatic, it has added a change to subsection (c)(1) to make automatic the consolidation of an appeal with the electric utility's DCRF proceeding before the commission. As a result, the commission has deleted proposed subsection (e)(6)(C), which addressed consolidation of appeals. In addition, the commission has changed subsection (c)(1) to clarify that the automatic suspension of the governing body's interim and final decisions occur at the times they took effect, in order to ensure a system-wide DCRF.

Reduction in the Timeline

Electric Utilities commented that PURA §36.210 requires that the timeline for processing a DCRF request be “processed in accordance with an expedited procedure,” and the statute further mandates that the commission adopt rules that provide for filing requirements and discovery consistent with the expedited procedure. Electric Utilities stated that while the commission's proposal to provide for a 145-day timeline is more expedited than the 185-day period for a comprehensive base-rate proceeding, a DCRF request could be processed faster than 145 days while maintaining the integrity of the process. Electric Utilities proposed a 125-day timeline instead.

Electric Utilities remarked that because the statute and rule require 45 days’ notice to customers of a change in distribution costs, the proposed rule necessarily provides 100 days for the commission to review the filing, and that would be 40 days longer than the 60-day period allowed for the commission to review a transmission service provider's request to change its transmission cost of service. Electric Utilities commented that they do not believe that it should take any longer to review and approve a DCRF application than it does to review and approve an application to change the transmission cost of service, but in the spirit of compromise Electric Utilities proposed to split the difference between the 60- day period for a transmission cost of service application and the 100-day period proposed in the draft rule. That compromise would allow the commission 80 days to review and approve a DCRF.

Electric Utilities noted that the commission may hear complaints that an 80-day period is unworkable because municipalities have 60 days under the proposed rule to consider the DCRF application and that the 80-day period would leave only 20 days for the commission to consider and

approve the application after the municipalities act on the utility's application. Electric Utilities stated, however, that because of the statutory directive that DCRF rates be instituted on a system-wide basis, the commission would necessarily have to consider each utility's DCRF application, regardless of how the individual municipalities rule on the application; therefore, the commission's internal review process would not need to wait for action by municipalities on the DCRF requests. Electric Utilities provided alternative language that reflected their recommended 125-day review period.

State Agencies opposed the suggestion that the time limits proposed to review the DCRF request should be shortened further, stating that they did not see what harm would be remedied by the exclusion of 20 additional days from the rules proposal. Additionally, State Agencies replied that no utility would be driven to financial ruin, no bond rating would be lowered, and no distribution capital would suffer by allowing at least the 145 days for an adjustment proceeding. CEP, CORE, Oncor Cities, and OPC also urged the commission to reject the changes to the timeline proposed by Electric Utilities, because the proposal would overlook key aspects of municipal jurisdiction over utility rates and misinterpret PURA §36.210. CEP commented that automatic appeals should be rejected by the commission.

Commission Response

The commission declines to adopt Electric Utilities' request to shorten the commission's time to review a TDU's DCRF application from 100 days to 80 days. The commission disagrees with Electric Utilities' comment that it should not take any longer to review a DCRF application than it does to review an interim TCOS factor (ITF) application. A DCRF

proceeding will require more resources than an ITP proceeding. A key difference between DCRF and ITP proceedings is that in a DCRF proceeding, the commission must determine whether the electric utility is earning more than its authorized rate of return using weather-normalized data. Although the commission intends to avoid turning this determination into a comprehensive cost-of-service review, the determination will require significant resources.

In addition, for a TDU, compressing the timeline 20 days would have little benefit. In order to reduce the number of times in a year that a REP is required to implement TDU rate changes, it is important that TDUs implement DCRFs on September 1, pursuant to subsection (e)(6)(D) of the DCRF rule. September 1 is a day on which ERCOT TCRF updates are made pursuant to §25.193(b)(1) (relating to Distribution Service Provider Cost Recovery Factor (TCRF)). Under subsection (c)(2) of the DCRF rule, a TDU can file a DCRF application as late as April 8. Moving this date by 20 days, in either direction, would not change the effective date for the DCRF. In addition, delaying the date by 20 days to April 28 would not affect the data used in the DCRF application—data as of December 31 of the prior year. Although delaying the application deadline to April 28 would give a TDU more time to prepare its application, the commission concludes that it is better to keep these 20 days available for review of the DCRF application.

Number of DCRF Filings per Year

REP Coalition commented that consistent with PURA §36.210(d), proposed subsection (c)(1) includes a provision that limits DCRF updates to once per calendar year. REP Coalition commented that they strongly support this provision in the proposed rule, stating that limiting the

number of DCRF updates to once per calendar year would permit electric utilities to timely recover their additional distribution-related capital costs pursuant to PURA §36.210, while also placing a reasonable restriction on the number of price changes that retail customers would experience each year as a result of changes in distribution-related capital costs. REP Coalition commented that restricting the number of DCRF adjustments to once per calendar year means that a REP would adjust its retail prices no more than once a year to reflect any change in a TDU's DCRF, and REP Coalition commented that this approach to implementing PURA §36.210 falls within the parameters of existing commission policy. REP Coalition stated that limiting the number of DCRF adjustments to once per calendar year would lighten the administrative burden of implementing new and revised TDU rates and moderate the administrative costs that all parties participating in commission DCRF proceedings would bear.

Commission Response

The commission agrees with the REP Coalition that this provision should remain in the rule.

Pending Proceeding

Electric Utilities commented that the last two sentences of §25.243(c)(1) would not allow for a DCRF filing while a base-rate proceeding for the utility is pending. Electric Utilities also commented that a DCRF filing application would be dismissed if the utility or commission initiates a base-rate proceeding during the pendency of a DCRF filing. Electric Utilities submitted that some accommodation should be given in instances when a base-rate proceeding has been extended beyond the statutory time frame. Additionally, Electric Utilities commented that if a DCRF proceeding is well along in the process when a base-rate proceeding is initiated, the DCRF

proceeding and work should not be dismissed and discarded. Electric Utilities pointed out that no similar prohibition exists for transmission cost adjustments. Electric Utilities also commented that four rate changes between base-rate proceedings should mean between final orders that change rates, and Electric Utilities recommended amending subsection (c)(1) to state that an electric utility shall not apply for a DCRF filing within 185 days after an electric utility has initiated a base-rate proceeding. Electric Utilities further commented that an electric utility's application for a DCRF filing should be dismissed if the electric utility or commission initiates a base-rate proceeding within 60 days after the electric utility has initiated a DCRF filing proceeding.

CEP, CORE, Oncor Cities, State Agencies, and TIEC disagreed with Electric Utilities. CEP replied that the proposed rule would be a reasonable resolution of the issue of overlapping proceedings and that the commission should reject Electric Utilities' proposal. State Agencies replied that Electric Utilities had not supported with legislative history their contention that a base-rate case and annual adjustment can proceed simultaneously. CORE and Oncor Cities also urged the commission to reject Electric Utilities' requested modification to the proposed rule for allowance of concurrent base-rate and DCRF filings. Oncor Cities commented that there were no sound policy reasons for allowing utilities to pursue simultaneous rate relief via the base-rate and DCRF processes. TIEC commented that the implementation of a DCRF while a base-rate proceeding is pending would be excessive and unnecessary, and should be rejected. TIEC also stated that updating rates four times without a base-rate proceeding would be a more than generous reduction to regulatory lag and utilities would not also need the ability to implement a DCRF in the middle of a rate proceeding; further, a DCRF proceeding would not need to be completed once a utility filed a base rate case even if the DCRF proceeding was far along in the process. TIEC replied that there would be no

need to change rates in quick succession, and therefore §25.243(c)(1) should be adopted as proposed.

Commission Response

PURA §36.210(d) states that an electric utility may adjust its rates under the section “not more than once per year and not more than four times *between* comprehensive base rate proceedings.” Because the phrase “between comprehensive base rate proceedings” is vague, the commission has discretion in the manner in which it implements the phrase, with the end points of the discretionary range being that a comprehensive base-rate proceeding cannot be pending during a DCRF proceeding (as in the proposed rule) or only one DCRF proceeding can be completed between the final orders of successive comprehensive base-rate proceedings.

Allowing an electric utility to apply for a DCRF while a comprehensive base-rate proceeding is pending would be problematic, because the rate-class allocation factors in the pending comprehensive base-rate proceeding would not yet be determined by the commission. Using the rate-class allocation factors from the immediately preceding comprehensive base-rate proceeding could result in the DCRF being calculated using allocation factors that would be outdated by the time the DCRF went into effect.

Although subsection (e)(6)(D) of the DCRF rule contemplates that the presiding officer will approve the DCRF application within approximately 145 days after it is filed, it remains to be seen how often, if at all, the presiding officer will deviate from this timeline. An electric utility should not have to delay a comprehensive base-rate application, or withdraw a DCRF

application, because completion of its DCRF takes longer than 145 days. In addition, the problem of outdated rate-class allocation factors would not be an issue in this scenario, because the DCRF would be terminated or set to zero once the new base rates became effective. The commission has changed subsection (c)(1) accordingly.

Wholesale Service over Distribution Facilities

Electric Utilities commented that at least one utility, Oncor, has a separate wholesale transmission tariff rate schedule for the provision of wholesale service over distribution facilities through an interconnection at distribution-level voltage. Electric Utilities stated that to the extent that additional distribution investment would be properly allocated to these customer classes, the rule should be clarified to remove any ambiguity regarding the applicability of a DCRF to wholesale customer classes that utilize distribution facilities. OPC agreed, and Electric Utilities provided language reflecting its recommendation.

Commission Response

The commission agrees with OPC and Electric Utilities that PURA §36.210 does not limit a DCRF to retail distribution service. The commission reflected this conclusion in proposed subsection (a), which provides that the section applies to electric utilities that provide wholesale or retail distribution service. To reinforce this conclusion, the commission has changed subsection (c)(1) of the rule to address this issue.

Terminology

State Agencies argued that the proposed rule should not depart from statutory language referring to a DCRF rather than a “periodic rate adjustment.” Stage Agencies additionally stated that in relabeling the periodic rate adjustment mechanism a “DCRF,” the proposed rule would create a new, and undefined, term: “DCRF update.” State Agencies commented that both the statute and the proposed rule formula contained in §25.243(d)(1) use the previous base rate case as the baseline, and “DCRF update” would imply that a new baseline would be used. State Agencies asked that the references to “DCRF” and “DCRF update” be stricken and the statutory term, period rate adjustment, be used.

Commission Response

Use of the term “DCRF” is helpful to distinguish the periodic rate adjustment in this rule from periodic rate adjustments in other rules, such as the “Interim Update of Transmission rates” in §25.192(h)(1) (referred to in this order as interim TCOS factor or ITF), the “Distribution Service Provider Transmission Cost Recovery Factor” in §25.193 (referred to in this order as ERCOT TCRF), the “Transmission Cost Recovery Factor for Certain Electric Utilities” in §25.239 (referred to in this order as non-ERCOT TCRF), and the “energy efficiency cost recovery factor” or “EECRF” in §25.181(f). For ease of reference, the commission has defined and used throughout the adopted rule a “DCRF proceeding” to mean a proceeding conducted pursuant to this section in which creation or amendment of a DCRF is considered on application of an electric utility to the commission pursuant to subsection (c)(1). This change eliminates the need to refer to a DCRF update. In addition,

for readability, the commission has split paragraph (1) of subsection (c) into subparagraphs.

Statutory Requirement

Walmart commented that as proposed the rules could be interpreted to mean that approval of a DCRF is a matter of right upon the filing of an application, or perhaps as somehow eliminating other provisions of PURA, and these interpretations would be inconsistent with the applicable statutes and the proposed rules should be clarified to avoid any such misinterpretation. Walmart noted, for example, that PURA §36.003(a) mandates that electric utility rates be “just and reasonable,” and PURA §36.006 places on utilities the burden of proving that a proposed rate change is just and reasonable. Walmart commented that these requirements would not be eliminated by SB 1693, but rather SB 1693’s possible allowance of a DCRF would appear to supplement these types of long-standing statutory requirements.

Walmart stated that SB 1693 also clearly allows the commission to deny an application for a DCRF. Reasons for denial would not be expressly limited to reasons enumerated in SB 1693;—conceivably, there could be other reasons for denying a DCRF application. Walmart suggested the following addition to §25.243(c)(1): “Any such application shall be evaluated consistently with all applicable statutory provisions.”

Commission Response

In the DCRF rule and the DCRF form being considered in Project Number 39466, the commission has delineated to the extent feasible the requirements an electric utility must meet

to obtain approval of a DCRF. Nevertheless, the commission agrees with Walmart that a DCRF must meet all applicable PURA requirements. The commission has changed adopted subsections (b)(3), (e)(1), (e)(5), and (f)(7) to make this requirement explicit.

Proposed §25.243(c)(2): Application for DCRF or DCRF Update—Requirements Applicable to TDUs

REP Coalition and Electric Utilities commented that in proposed subsection (c)(2), the word “update” should be added after the second use of the term DCRF in the second sentence.

Consistent with their recommended timeline of 125 days, Electric Utilities suggested that the application filing dates should allow for the filing for a DCRF filing only during the period April 21 through April 28.

Commission Response

As discussed above concerning §25.243(c)(1): *Application for DCRF or DCRF Update—General Requirements*, the commission has defined and used throughout the adopted rule a “DCRF proceeding,” which eliminate the need to refer to a DCRF update. As discussed above in §25.243(c)(1): *Application for DCRF or DCRF Update—General Requirements*, the commission declines to change the DCRF application filing period for a TDU.

Proposed §25.243(c)(3): Application for DCRF or DCRF Update—Requirements Applicable to Other Electric Utilities

CEP commented that the filing deadlines established for TDUs would effectively require a TDU to file the application at the same time every year. CEP stated that the provisions of this paragraph applicable to other electric utilities, however, would allow the utility a greater time period between filings in which to make filings, so that the time between general rate reviews, if no other intervening action occurs, could be considerably longer for utilities in areas not subject to customer choice. CEP commented that this paragraph should be revised to narrow the period for subsequent filings.

Electric Utilities replied that this change would be unnecessary, and if made, would put greater restrictions on the non-ERCOT utilities. Electric Utilities stated that the time period for ERCOT utilities was set to accommodate concerns by retail electric providers about having to accommodate randomly timed rate changes throughout the year, and there is no reason to believe that the time period between comprehensive base-rate proceedings would be any different for ERCOT and non-ERCOT utilities. Electric Utilities stated that for both, the electric utility would be limited to one DCRF rate adjustment per year, and no more than four rate adjustments between comprehensive base-rate proceedings. The only difference would be that ERCOT utilities would be given a narrow window in which to file each year, if they chose to do so, and the non-ERCOT utilities would not. Electric Utilities stated that the time period between comprehensive base-rate proceedings in both situations would depend on whether the electric utility chose to file for a DCRF rate change in a particular year, and whether or not the electric utility would be restricted to a particular filing

window in each year would not make the time period between comprehensive base-rate proceedings any shorter or longer.

Commission Response

The commission agrees with Electric Utilities.

Section 25.243(d)(1): Calculation of DCRF Formula—DCRF Formula

Allocation of Costs and Revenues in the DCRF Formula

TIEC commented that while the DCRF formula in the proposed rule appropriately calculates the utility's incremental distribution costs and updates the billing determinants, it completely ignores the requirement in SB 1693 to allocate costs “consistent with the “manner” in which they were allocated in the last rate proceeding. In other words, the DCRF rates should reflect what the results would be if the allocation methodology from the last case were re-applied based on updated information. TIEC submitted that the proposed formula freezes the percentage of the total distribution costs allocated to each class at the level assigned in the last base rate case, and as a result, the formula disproportionately raises rates for classes with less load growth and imposes lower costs on classes with more growth. TIEC argued that the statutory provision does not require each class to continue paying the same percentage of the total distribution costs, irrespective of relative changes in class size or demand, and that changing rates to include new investments and new billing determinants without also updating class allocations is not “consistent with the manner in which” costs are allocated in a rate case.

TIEC proposed an alternative formula that it believes complies with the requirements of SB 1693. TIEC argued that its formula follows cost-causation principles by allocating a greater share of the incremental costs to a class that is growing and causing more of the incremental distribution costs to be incurred, and those costs will be spread among a greater number of customers in that class. TIEC also noted that under its formula, once the updated revenue requirements are divided by the new billing determinants for each class, all customers end up paying the same per-unit DCRF rate, regardless of which class they are in. TIEC argued that this is the correct result—the utility recovers the same total amount as it would under the formula in the proposed rule, but the costs are distributed equitably among the classes based on cost-causation and changes in demand, and consistent with the “manner” in which costs were allocated in the last rate case.

State Agencies similarly opined that the proposed formula will not achieve, as the statute requires, an allocation between the rate classes that is “consistent with the manner in which costs were allocated...in the electric utility's most recent base rate statement of intent proceeding....” State Agencies argued that the Legislature plainly intended the previous base-rate case to serve as the model for allocation of the incremental distribution capital costs recovered through the DCRF, after crediting additional revenues recovered through base rates against the total amount of costs sought. State Agencies commented that nothing in the statute provides that load growth revenues should be broken down into discrete rate classes in calculating the necessity and amount of the periodic adjustment. State Agencies further commented that under the proposed formula, the system distribution cost increase is allocated using an allocation factor from the last base-rate case, but the system revenues recovered from base rates are assigned to each class based on the actual revenue change for that particular class. State Agencies

expressed its belief that the legislative objective of accounting for load growth is realized by taking the total incremental qualifying distribution costs, offsetting them with the load growth revenues attributed to distribution investments, and then allocating any resulting net system distribution increases to rate classes. State Agencies argued that the proposed formula would result in an allocation of the net system distribution cost increase that is not consistent with the manner that the distribution capital costs were allocated in the utility's last base-rate case, because the formula calculation imposes greater rate increases for the classes with lower (or no) load growth. State Agencies commented that it is not the Legislature's intention to impose such a disparate rate impact on any class and that classes with lower load growth should not be responsible for more of the increase than the customers taking services from the classes experiencing more load growth and for whom the additional distribution capital expenses have been arguably incurred. State Agencies stated that its proposed formula would allocate the system distribution capital cost increase and the system revenue change based on the same allocation factor and result in an allocation of the net distribution cost increase that is consistent with that in the last base rate case. State Agencies claimed that its proposed formula would be an allocation among different classes that more nearly meets the objectives of PURA §36.210(a)(2) and (3) and will not result in greatly disparate rates.

OPC commented that the enabling legislation contains two co-equal requirements that must be met in implementing a DCRF adjustment: (1) recover invested capital consistent with the allocation among classes used in the most recent general base rate case; and (2) account for changes in load and customer growth that have occurred since the most recent general base rate case. OPC commented that while some parties (TIEC and State Agencies) have advocated that

the DCRF formula should be changed so that the effects of changes in the number of utility customers, energy consumption, and demand on revenues being recovered through base rates are used to change the cost allocation that the commission approved in the utility's most recent base rate case, these advocates seek to change the DCRF formula in order to take advantage of anticipated customer and load growth in the residential class and apply it to subsidize their rate classes. OPC stated that the position of these parties inappropriately mixes the rate design requirement of PURA §36.210(a)(2)—an update of revenues based upon changes in billing determinants, which are normally used on a class-by-class basis for rate design under well-established ratemaking principles—with the cost allocation requirement in PURA §36.210(a)(3). OPC pointed out that cost allocation is based on numerous underlying weighted factors in an involved cost of service study as part of a general base-rate case, and that any modification of the allocation factors determined in the most recent base-rate case, as sought by these parties, would require a complete re-computation of the utility's class cost of service study in order to achieve a fair and accurate result.

OPC additionally commented that in addition to being inconsistent with traditional ratemaking principles, such a proposed change to the DCRF formula would result in a failure to adhere to the requirement in PURA §36.210(a)(3) that the invested capital costs to be recovered through the DCRF are to be allocated to each rate class consistent with the manner in which invested capital costs were allocated in the utility's most recent base rate case, and that injecting into cost allocation a consideration of changes in revenues generated by the different rate classes as a result of changes in their respective billing determinants is completely inconsistent with the manner in which costs are allocated in base-rate cases, and therefore contrary to PURA

§36.210(a)(3). OPC argued that the commission should reject this attempt to force residential customers to subsidize other rate classes and to pay more than their allocated share of costs as determined by the commission, often based upon a settlement agreement, in the utility's most recent base-rate case.

State Agencies commented that OPC argues that other parties seek to use the residential class load-growth revenues as a subsidy to other classes, but that it is in fact the proposed commission formula that results in a subsidy to the residential class by potentially shifting most of the distribution capital costs into classes that did not cause them. State Agencies commented that OPC argues that PURA §36.210(a)(2) and (3) establish co-equal considerations that the proposed rules must implement, but State Agencies opined that the Legislature intended the DCRF rate design process to follow the sequence that ordinarily is used in base-rate cases, with the preceding base-rate case as the template. State Agencies commented that like any other rate design process, rules to implement the DCRF rates should involve the three steps of: determining the total qualifying costs that can be recovered through the DCRF, allocating the recoverable qualifying costs among customer classes, and designing the DCRF rate for each class by dividing each class's allocated cost by the appropriate determinant. State Agencies argued that its proposed formula follows this sequence, and that the normal design process does not typically involve crediting the load growth for one class entirely against the rates that would otherwise apply to that class. State Agencies opined that its proposed formula complies with PURA §36.210(a)(3) and does not, as OPC charges, modify the allocation factors determined in the most recent base rate case.

TIEC commented that it agrees with the State Agencies' conclusion that the proposed formula violates the requirements of PURA §36.210(a)(3), and that the DCRF formula in the proposed rule arbitrarily and inequitably keeps additional revenues from load growth within the classes. TIEC commented that this means that customers in classes with greater growth will pay lower per-unit DCRF rates, and customers in classes with less load growth receive a disproportionate rate increase. TIEC stated that to avoid this result, the State Agencies' formula offsets the total incremental distribution investment with the total distribution-related revenues from load growth on a utility-wide basis, rather than doing this on a class-by-class basis, and this is the correct approach. TIEC stated, however, that the State Agencies' formula then applies the percentage allocation factors from the last rate case to the incremental revenue requirement to determine the revenue increase for each class, and then calculates the DCRF by dividing this class revenue increase by the class's updated billing determinants. TIEC argued that the State Agencies' formula still results in disparate rate increases for customers in different classes, because it applies outdated allocation factors to the incremental revenue requirement. TIEC submitted that allocation factors are directly related to class billing determinants, and that it is improper ratemaking to recognize that a class's billing determinants have changed, but then to refuse to update the allocation factors to reflect this change. TIEC argued that under its approach, the utility recovers the same overall amount, but customers pay the same amount for the same unit of usage regardless of which class they are in. TIEC argued that by adjusting the per-unit rates rather than the total pot of dollars assigned to each class, its formula naturally tracks changes in class compositions and results in a proper cost allocation. TIEC submitted that while the State Agencies' formula is an improvement upon the formula in the rule, it still does not fully comply with SB 1693, and TIEC's formula should be adopted instead.

OPC disagreed with TIEC and State Agencies regarding the way the DCRF formula should operate and argued that a step-by-step review of the formula readily demonstrates that the allocation of costs among classes in the proposed rule is consistent with the allocation requirement in PURA §36.210(a)(3). OPC argued that the rule's proposed formula tallies incremental cost and allocates it according to the class allocation factors established in the last base rate proceeding, and that TIEC's and State Agencies' contention that the formula does not allocate costs in a manner consistent with the last base-rate proceeding, and therefore runs afoul of the statute, is baseless.

OPC further commented that both TIEC and State Agencies propose amendments to the formula in an attempt to remedy the perceived misallocation of costs, but their arguments confuse the relationship between cost allocation, revenue collected through base rates, revenue collected through a DCRF, and rates. OPC stated that this confusion results in proposed formulas by TIEC and State Agencies that create cross-subsidization among the rate classes, notably subsidizations of the rate classes they represent, and that at their core, the formulas socialize the economic benefit of load growth. OPC observed that the amount of revenue to be collected from each class is determined in a base-rate proceeding, and given the customer count, energy consumption, and energy demand of a particular class, rates are designed to collect this class revenue requirement exactly. OPC pointed out, however, that base rates are not a revenue guarantee, because future years deviate from the test year used to establish rates, and along with fluctuations in billing determinants, the revenue actually collected by the utility from each class will differ from the revenue requirement used to set base rates. OPC noted that

the growth of billing determinants over time, and the resultant increase in utility revenue, is generally referred to as “load growth,” and that load growth is an issue in the computation of the DCRF because the statute requires the DCRF rate to account for changes in the number of a utility's customers, energy consumption, and energy demand on the amount of revenue the utility recovers. OPC expressed its support for the basic approach in the formula in the proposed rule that makes this adjustment by subtracting the revenue impact of class load growth from the incremental costs to be recovered from each class; the resulting revenue requirement determines the class's DCRF, ensuring that one class is not subsidizing another class by virtue of the changes being recognized through the DCRF.

OPC further stated that State Agencies' formula generally follows the formula in the proposed rule but takes a different approach to the load growth adjustment: instead of calculating the adjustment on a class-by-class basis, State Agencies would take the entire incremental cost to be recovered through a DCRF, reduce it by the entire system revenue impact of load growth, and allocate the net amount among rate classes by the allocation factors approved in the last base-rate proceeding to determine the DCRF for each class. OPC stated that this approach is inequitable because it gives each class the economic benefit of the system's load growth and not the benefit of its own load growth, because classes with load growth above the system average would donate the economic value of their “extra” load growth to classes with load growth below the system average. OPC commented that for these donating classes, the DCRF is set too high — the combination of the revenue collected through base rates and the revenue to be collected through the DCRF is higher than the class's revenue requirement. Likewise, the classes receiving the donation will pay less through base rates and the DCRF than the revenue requirement assigned to them.

Regarding TIEC's proposed formula, OPC commented that the formula modifies the load-growth adjustment mechanism in the proposed rule, and that just as with the formula proposed by State Agencies, TIEC's formula would result in improper cross-subsidization among rate classes. OPC noted TIEC comments that "the DCRF rates should reflect what the results would be if the allocation methodology from the last case were reapplied based on updated information." But OPC stated that updates to information are controlled by PURA §36.210 — a DCRF is to account for changes in specific categories of utility costs and to account for changes in the amount of revenue recovered through base rates. Thus, outside of the updates to billing determinants, the only other update a DCRF should include is the change in costs related to distribution investment that occur subsequent to a rate case. OPC opined that no section of the statute directs the commission to revisit a base-rate case and re-investigate the costs subsumed in base rates and how classes' relative cost responsibility varies with relative changes in class sizes. Yet this is exactly what TIEC's proposal would have the commission do.

OPC commented that the numerical example TIEC provided in its comments presumes that a class with an increased customer count has caused more of the incremental distribution costs than the other class that has shrunk. Furthermore, OPC stated that TIEC's example presumes that cost-causation principles should allocate a greater share of the incremental costs to the growing class. OPC commented that these presumptions are problematic, because while it may or may not be true that a growing class is responsible for a larger percentage of incremental distribution investment than a shrinking class, the degree to which this may be true

is not readily apparent, would be a subject of litigation, and is properly explored only in a full base-rate proceeding. OPC stated that, additionally, the presumptions fail to consider that growth in a customer class is also responsible for growth in the revenue that the class brings to the utility through base rates, and the growth in revenue may partially, completely, or more than completely offset the incremental costs potentially associated with the class's growth. OPC stated that it is this fact that underlies the statutory requirement for a DCRF to include changes in revenue due to load growth, and the formula in the proposed rule develops DCRF rates that match TIEC's criterion that the DCRF rates should apply the allocation methodology from the base-rate case to information updated as part of the DCRF proceeding. OPC commented that incremental costs, which are the only updates to cost information that are permissible, are allocated among classes using the allocation methodology from the last rate case; however, TIEC modifies the load growth adjustment in a way that makes an end-run around the statute, effectively using the DCRF as a vehicle for "updating" the allocation of costs subsumed in base rates by adjusting the overall revenue (base rate plus DCRF) collected from each class. OPC commented that, similar to the State Agencies' formula, TIEC's formula socializes the revenue impact of load growth by first computing the total DCRF revenue requirement (incremental costs less increased revenue resulting from load growth) before parsing the revenue requirement into the various class revenue requirements, and as a result TIEC's formula would create cross-subsidization. OPC commented that TIEC's formula goes even further astray in that it does not rely on the allocation factors from the base-rate case whatsoever, but parses the overall DCRF revenue requirement into class requirements by a new allocation mechanism. OPC commented that it recommends that the DCRF formula presented in the proposed rule, subject to OPC's suggested modifications, be adopted. OPC stated that

this formula adheres to the statute by allocating incremental distribution-related costs by means of the allocation methodology utilized in the last base-rate case, and because this methodology is established and matters of allocation are typically contentious, utilization of the methodology limits litigation of allocation issues and supports the abbreviated schedule for a DCRF proceeding as envisioned by the statute.

Oncor Cities commented that although TIEC and State Agencies suggest different modifications to the formula, both recommendations have the effect of indirectly changing the previously adopted allocation of distribution plant costs, resulting in an allocation that is contrary to the requirement of PURA §36.210(a)(3), and the formula set out in the proposed rule is more consistent with that provision. Oncor Cities stated that TIEC focuses on the words “consistent with the manner” from §36.210(a)(3), in order to argue that the numeric allocations adopted in the last base-rate case should be ignored in the DCRF formula. Oncor Cities further commented that the TIEC formula completely deletes any reference to the class allocation approved in the previous base-rate case. Oncor Cities observed that the commission has previously addressed a similar issue with respect to stranded cost allocation, where the statute pertaining to class allocation for stranded costs recovery has a similar reference to the allocation adopted in the utility's previous base-rate case. Oncor Cities observed that, similar to its arguments here, TIEC has previously proposed to modify stranded costs recovery allocations to reflect the change in size of each class since the utility's last base-rate case, but that the commission determined that the law's allocation requirement should be implemented by applying the specific numeric class allocations adopted in the previous base-rate case instead of TIEC's proposed interpretation. Oncor Cities further commented that the commission's interpretation and use of

the historic numeric allocators from the previous rate case have been affirmed by the Supreme Court as reasonable. Oncor Cities stated that even assuming acceptance of TIEC's argument that §36.210(a)(3) should be based on the previous rate case's "manner" of class allocation rather than the historic allocation from that rate case, TIEC's formula does not replicate the manner or method of allocating costs in the previous base-rate proceeding. Oncor Cities argued that TIEC's formula makes no reference to the methodology for allocating distribution investment in the utility's base rate case, but that instead, TIEC proposes to apply percentage increases to the classes' revenue growth. Oncor Cities averred that an accurate attempt to apply the previous "manner" of cost allocation to current load data would be as complicated as replicating the class cost of service study, and the composite allocation of distribution investment is dependent on numerous allocation factors applied to specific plant accounts, as well as indirect allocations computed by the cost allocation model. Oncor Cities argued that, for this reason, the use of fixed class allocations from the prior rate case is a more feasible procedure for the application of §36.210(a)(3).

Oncor Cities additionally commented that TIEC's proposal also glosses over the fact that "billing determinants" are not the same as the data used to allocate costs to classes, and that TIEC's proposed formula skips the allocation step and proceeds directly to billing determinants that are developed for rate design. Oncor Cities noted, however, that billed demands and kilowatt-hours at the meter are not the same as load data that form the basis for class allocation, and for this reason, the hypothetical examples in TIEC's comments are not an accurate portrayal of class allocation methods. Oncor Cities commented that it would not be typical for class demand allocation methods to result in equal kilowatt-hour charges among

classes, as implied in TIEC's examples in its comments. Oncor Cities stated that the relationship between kilowatt hours and classes' demands — the underlying data for the allocation factors — will depend on the class load factor for the period.

Oncor Cities contended that State Agencies' proposal is an improvement over TIEC's formula to the extent that State Agencies' formula retains the previous rate case class allocation factors as a multiplier, but that deduction of total revenue growth from incremental distribution investment indirectly changes the class allocation, which is inconsistent with §36.210(a)(3). Oncor Cities pointed out that for ratemaking purposes, the revenues paid by a class are directly assigned to that class, but the effect of State Agencies' proposal is to allocate total revenue growth among the classes, rather than credit each class with the revenues it paid. As a result, revenue growth paid by one class may offset the amount of costs allocated to another class. Oncor Cities stated that this result is the virtual definition of "cross-subsidy." As set out in the proposed rule, revenue growth generated by a class is used to offset the incremental distribution costs allocable *to that class*. For those reasons, Oncor Cities urged the commission to maintain the allocation approach set forth in the proposed rule.

COH commented that several participants recommended revisions to the class allocations in the DCRF formula, and that as proposed, the formula provides revenue credits for customer classes with load growth as compared to class usage levels in the utility's prior rate case. COH commented that if a customer class grows more, relative to other classes, then it would properly receive a larger revenue credit and, therefore, be allocated a smaller percent of the increase in distribution class costs. COH observed that parties representing customer classes that do not

expect to grow much obviously do not favor this approach and seek to obtain a portion of this growing class's revenue credit. COH stated that it does not support proposals by TIEC and State Agencies to allocate the revenue credits on an average system basis and considers the proposals to be self-serving and unsupported.

Electric Utilities agreed with OPC's assertions regarding TIEC's and State Agencies' proposals to co-mingle rate design and cost allocation requirements to their advantage by the use of alternative formulas. Electric Utilities stated that the commission should flatly reject the proposed changes. Electric Utilities commented that PURA §36.210(a)(3) clearly requires that the DCRF formula "be consistent with the manner in which *costs for invested capital* described in this subsection were allocated to each rate class, as approved by the commission," in the electric utility's most recent comprehensive base-rate case. Instead of using allocation factors based on the amount of invested capital, as the statute clearly requires, the approach suggested by TIEC and State Agencies first nets the overall change in revenues against the increase in expenses related to the distribution invested capital and then allocates the net increase to the classes based on their relative share of the overall revenues. Electric Utilities stated that, in essence, these alternative approaches calculate a new allocation factor to take advantage of revenue increases in one or more classes and spread it across all classes to subsidize those classes for which growth in revenue is not as significant or perhaps even declines, and that in doing so, the formulas proposed by TIEC and State Agencies unfairly penalize a class whose growth is enough to cover the new investment allocated to its class. Electric Utilities stated that nothing in the statute requires that the average DCRF increase (or decrease) be applied virtually equally to all rate classes, but that rather, each class should stand on its own. Electric

Utilities stated that TIEC's and State Agencies' approaches to calculating a new revenue-based allocation factor is in direct conflict with the requirement in the statute, which clearly specifies the use of the capital-based allocation factors approved in the utility's last rate case, and for this reason, as well as those cited by OPC, Electric Utilities urged the commission to reject TIEC's and State Agencies' alternative formulas.

Commission Response

For the calculation of the DCRF, commenters recommended three different types of allocation formulas, including the formula in the proposed rule. The proposed rule's formula credits to each class the actual distribution-related revenue collected from that particular class and then allocates to each class the system distribution cost increase on the basis of cost allocation factors from the utility's base-rate proceeding. The formula then determines the DCRF for each class by taking the difference between the class's credited incremental revenues and allocated costs and dividing it by the class's new billing determinants.

In contrast, TIEC's proposed formula assigns both load-growth revenues and incremental costs on the basis of current billing determinants. TIEC argues that allocation factors are directly related to class billing determinants, and while the commission acknowledges that this assumption generally reflects the relationship between load growth and incremental capital investment as typically determined in a comprehensive base-rate proceeding, to make this assumption in an expedited DCRF proceeding is problematic. As noted by several parties, cost allocation, when litigated in a comprehensive base-rate

proceeding, is based on numerous underlying factors and analyses of how classes' relative cost responsibility varies with load data and relative changes in class sizes, and any modification of the allocation factors determined in the most recent comprehensive base-rate proceeding would require a complete re-computation of the utility's class cost-of-service study to achieve an accurate result. It is not appropriate, in the context of a DCRF proceeding, to assume that there is a 100% correlation between updated billing determinants and the load data used in the cost-of-service study to allocate costs to classes in the last comprehensive base-rate proceeding. The commission thus rejects TIEC's proposal to use updated billing determinants as the basis for allocating both load-growth revenues and incremental capital-related costs.

The third approach, as advocated by State Agencies, has certain elements of both the proposed rule's formula and TIEC's recommended formula. It credits load-growth revenues on a utility-wide basis, as does TIEC's proposal, but it allocates incremental costs to each rate class using allocation factors from the utility's base-rate proceeding, as does the formula in the proposed rule.

The commission agrees with TIEC and State Agencies that, for the allocation of load-growth revenues, the DCRF formula should first offset the total incremental distribution capital costs with the total load-growth-related distribution revenues on a utility-wide basis, rather than on a class-by-class basis. Although some parties claim that this results in class cross-subsidization, subsidies can be ascertained only if specific cost-allocation information is ascertained, and because PURA §36.210 does not contemplate

cost allocation adjustments, the extent—or even the presence—of subsidization cannot be determined absent a comprehensive cost-of-service study. Moreover, as noted by State Agencies, nothing in PURA §36.210 provides that load-growth revenues should be allocated to discrete rate classes when calculating the DCRF, and applying system revenues across all classes minimizes the possibility of widely disparate DCRF rates across classes.

The commission concludes that, after offsetting system load-growth revenues against system incremental capital costs, the appropriate basis for allocating the remaining costs is to use the rate-class cost-allocation factors from the utility's base-rate proceeding, rather than cost allocations based on updated billing determinants as recommended by TIEC. This part of the adopted DCRF formula reflects the language in PURA §36.210(a)(3) that the DCRF must “be consistent with the manner in which costs ... were allocated to each rate class” in the base-rate proceeding. It is also consistent with the manner in which the proposed rule's formula allocated incremental costs.

Given the constraints of an expedited timeline for a DCRF proceeding, the commission concludes that the formula advocated by State Agencies is a reasonable balance between TIEC's recommended formula and the proposed rule's formula. Therefore, the commission finds that for the calculation of the DCRF, load growth should be “take[n] into account” by taking the total incremental qualifying distribution costs, offsetting them with the load growth revenues attributed to distribution investments, and then allocating

any resulting net system distribution cost increases to rate classes on the basis of the allocation factors from the base-rate proceeding.

PURA §36.210(a)(3) requires that a DCRF must “be consistent with the manner in which costs for invested capital described by this subsection were allocated to each rate class, as approved by the commission, in an electric utility's *most recent base rate statement of intent proceeding....*” (Emphasis added.) A statement of intent is filed when an electric utility initiates a base-rate proceeding, pursuant to PURA Chapter 36, Subchapter C. However, no statement of intent is filed when the commission initiates a base-rate proceeding, pursuant to PURA Chapter 36, Subchapter D. Taken literally, PURA §36.210(a)(3) would require use of the cost allocation from the utility’s most recent base-rate statement of intent proceeding, even if the commission had initiated a comprehensive base-rate proceeding since that proceeding. The commission does not interpret this provision literally, because to do so would lead to an absurd result, where the DCRF would be calculated using outdated rate-class allocation factors. Consistent with the proposed rule and without objection by any commenters, the adopted rule uses the rate-class allocation factors from the last comprehensive base-rate proceeding, regardless of whether that proceeding was initiated by the utility or the commission.

Inclusion of Formula in Rule

Stage Agencies and COH commented that it is inadvisable to put a complex formula into the rule, because the commission will lose the flexibility to adapt certain elements of the formula if they are demonstrated not to achieve the results prescribed by the statute. Stage Agencies

commented that inclusion of such a formula into a rule can have unintended consequences, and recommended that the proposed formula be replaced with language requiring that the DCRF be filed “on a form and in the manner prescribed by the commission.”

Electric Utilities disagreed, stating that the purpose of a rule is to prevent repeated litigation in contested proceedings, and this is especially important in what is designed to be an expedited proceeding of limited scope. Electric Utilities stated that while the formula appears complex, it is conceptually quite simple and no future “tweaks” should be necessary. Electric Utilities contended that this is particularly true since it is being modeled on the interim TCOS formula, which has been successfully utilized for a number of years. Electric Utilities stated that in order to prevent having to repeatedly litigate in the first several DCRF cases exactly how the adjustment should be calculated, the commission should set out the formula in the rule and avoid such unnecessary litigation. Electric Utilities stated that in light of the many comments suggesting a variety of changes to the formula — from whether ADFIT is included, to how revenues are accounted for, to how to properly allocate costs — failure to decide these issues now will ensure that numerous DCRF cases are litigated until all of the issues have been raised and considered by the commission, and even then, some parties will likely choose to re-litigate certain issues in the hope of the commission reversing its decision. Electric Utilities submitted that making final decisions in this rulemaking, and eliminating the repeated litigation of those issues, will be much more cost-effective for all of the entities involved.

OPC commented that, as evidenced by the sundry positions taken by participants in this rulemaking with respect to the form of the formula, the computation of a DCRF is itself a contentious issue, and

any certainty the final rule can provide with respect to the computation of a DCRF reduces the potential for litigation and the costs associated with an initial DCRF filing application. OPC commented that a reduction in the potential for litigation also supports the abbreviated schedule for a DCRF filing, and OPC stated its belief that it is possible to craft a formula in the current rulemaking that adheres to the statute. OPC pointed out that if the commission determines at some future date that changes to the formula are needed, it is not prevented from opening another rulemaking to revise the formula.

Commission Response

The commission agrees with Electric Utilities and OPC that inclusion of a formula in the rule provides clarity and minimizes controversial issues in DCRF proceedings, which is consistent PURA §36.210's requirement that a DCRF proceeding have an expedited procedure. As explained by Electric Utilities, the DCRF formula is conceptually simple and should not produce unintended results. In addition, a DCRF is calculated in a manner similar to interim TCOS rates, and interim TCOS rates have been calculated without controversy as to the formula for many years.

Definitions

COH stated that it had no major issues with the proposed formula, but expressed its belief that the definition of the variable $ALLOC_{class}$ should be clarified by using the word "approved" when referring to items from a utility's last comprehensive base-rate proceeding. CORE expressed agreement with COH's comments in this regard.

Electric Utilities and OPC commented that the definitions of the formulaic terms $DEPR_C$ and $DEPR_{RC}$ should be modified to reflect the fact that depreciation expense is calculated on the amount of gross investment as opposed to net investment.

Commission Response

The commission agrees with the recommendations of COH, Electric Utilities, and OPC and has modified the rule accordingly.

Distribution-Related Other Revenues

Oncor Cities commented that the DCRF formula should be modified to include changes in distribution-related other revenues (FERC Account No. 450-456). Oncor Cities stated that other revenues are used to reduce the base-rate revenue requirement allocated to customers, and include those received for activities such as telecommunications pole rentals, connect/disconnect fees, pole attachments, rental of land, etc. Oncor Cities commented that during the development of cost of service, distribution-related portions of the revenue are identified and deducted from distribution revenue requirements, and a more accurate reflection of revenue requirement associated with distribution-invested capital would include the change in distribution-related other revenues in the interval since the utility's most recent base rate case. Oncor Cities proposed a modification to the DCRF formula to address this issue.

Electric Utilities disagreed with Oncor Cities' recommendation for several reasons. Electric Utilities argued that Oncor Cities' suggestion goes beyond the statute, which clearly requires that the DCRF take into account changes in base revenue associated only with changes in

customer count, energy consumption, and energy demand. Neither in PURA §36.210(a)(2) or anywhere else in the statute does it mention the requirement to adjust for other revenues associated with activities such as pole rentals, connect/disconnect fees, etc. Electric Utilities additionally argued that the majority of these other revenues are derived from O&M-related services such as connect/disconnect, meter re-reads, etc., which are intended to recover the cost of the provision of these O&M services, and thus, using revenues that are designed to recover the cost of these services to offset an increase in expense related to capital investment would result in a misapplication of these revenues. Electric Utilities also argued that adjustments to other revenues are not included in the interim TCOS process from which the DCRF rule is closely patterned; these revenues are fixed in the interim TCOS and are appropriately only adjusted in full rate cases. Electric Utilities argued that for these reasons, the commission should reject Oncor Cities' attempt to add an adjustment for other revenues to the DCRF formula.

Commission Response

Distribution-related other revenues include revenues from O&M services. In addition, they are not expressly addressed in PURA §36.210. The commission declines to include them in the DCRF formula, but in a future rulemaking may consider requiring that distribution plant-related other revenues be included in the DCRF formula.

Lost Revenues

OPC commented that the DCRF formula in subsection (b)(1) of the proposed rule must be amended to eliminate the use of the DCRF as a means to grant utilities what OPC characterizes as “lost revenues.” OPC stated that the portion of the formula that relates to changes in billing

determinants for each rate class since the most recent base-rate case will produce a negative amount for a particular rate class if the billing determinants of the class have decreased since the most recent base rate case, and that such a decrease could be due to a variety of reasons, including general economic conditions as well as successful energy efficiency programs. OPC submitted that if this portion of the formula results in a negative amount, it will inappropriately require the rate class to make up for revenues not being collected by the utility from the class due to the decline in the class's billing determinants since the most recent base rate case, and will raise the rate charged to the class for a reason beyond the scope and purpose of PURA §36.210. OPC stated that PURA §36.210 is intended to only allow the utility to recover the revenue related to changes in distribution investment, not purported inadequate revenues from existing base rates, and that if a utility believes that current base rates are inadequate, the utility needs to initiate a base-rate case. OPC commented that in order to eliminate this inappropriate and unauthorized recovery, the DCRF formula must be appropriately modified, and OPC provided changes consistent with this point.

Oncor Cities commented that if OPC's proposed change were adopted, customer classes with load loss would be protected from any DCRF impact due to the loss of revenue within the class.

State Agencies disagreed with the "lost revenues" adjustment, stating that OPC's suggested changes would merely amend a proposed rule that State Agencies contend is flawed.

Electric Utilities commented that any DCRF adjustment will be prospective in nature, so there is no ability to recover any historical "lost revenues" due to reduced demand or energy

consumption. Electric Utilities stated that, with respect to the proposed DCRF formula, it does take into account the impact of both positive and negative changes in demand and energy consumption on the revenues related to the items being adjusted (depreciation, return on distribution-related invested capital, FIT, and other taxes). Electric Utilities commented that the proposed formula does so *because that is what SB 1693 requires*. Electric Utilities stressed that the statutory language does not in any way limit the impact on revenues to *positive* effects, or the impact caused by *increased* consumption or demand; rather, the language of the statute clearly requires *all* weather-normalized effects on the amount of revenues recovered through the utility's base rates related to the items being adjusted (depreciation, return on distribution-related invested capital, FIT and other taxes) to be taken into account in setting the DCRF. Electric Utilities contended that the proposed rule simply implements the statutory requirements.

Commission Response

Because the commission has changed the DCRF formula consistent with its prior discussion, the issue of “lost revenues” is moot.

Accounting for All Revenues

OPC commented that the DCRF formula must account for all growth in the utility's revenues being recovered through base rates to comply with PURA §36.210(a)(2). OPC argued that it is clear from the statutory language that the updating of the impact on revenue being recovered in base rates because of changes in the number of customers, energy consumption, and demand is not restricted to only the revenues derived from the utility's distribution invested capital, and there

is no such limitation in the statute, expressed or implied. OPC opined that the plain language of subsection (a)(2) requires the commission to account for all growth in the utility's revenues being recovered through base rates when making a DCRF adjustment, but that the DCRF formula in the proposed rule incorrectly restricts the updating of revenues to only the portion of the utility's revenues related to distribution invested capital. OPC provided changes to the formula to make the DCRF formula consistent with its interpretation of §36.210(a)(2). CEP expressed agreement with OPC's suggested alterations to the formula.

Electric Utilities disagreed that the statute requires that the adjustment to revenues in subsection (a)(2) must apply to all distribution-related revenues. Electric Utilities argued that OPC improperly attempts to read subsection (a)(2) in isolation, ignoring the language in (a)(1) that the tariff is to be adjusted up or down based on changes in the utility's distribution-related invested capital (as described in PURA §36.053), after consideration of the Uniform System of Accounts. Electric Utilities stated that there is no indication that the provisions in (a)(2) were designed to extend beyond the change in revenues related to distribution-related invested capital (including depreciation, return, and tax accounts) and pick up *all* distribution-related revenue changes, including those pertaining to O&M expenses such as salaries, pensions, gasoline prices, etc. Electric Utilities argued that those additional O&M-related revenues related to growth in usage are necessary to meet the utility's increased O&M-related costs related to that increased usage, and the concept behind the paragraph at issue is that if changes in consumption have increased the revenues related to distribution-related capital investment, then those increased capital-related revenues should be used to offset the amount of the rate increase arising from the new plant that has been constructed and placed in service. Electric

Utilities stated that (a)(2) does not explicitly exclude transmission revenues from its scope, but no party would argue that increased transmission revenues would also be used as an offset to increased distribution-related capital investment. Electric Utilities submitted that no such exclusion is necessary because the entire scope of SB 1693 and PURA §36.210 is limited to distribution-related capital investment. Electric Utilities contended that OPC's attempt to expand one paragraph of the section beyond the scope of the section itself is improper and should be rejected.

Commission Response

Taken literally, PURA §36.210(a)(2) would require that all of an electric utility's revenues resulting from load growth be taken into account in calculating the DCRF, including generation-related revenues, transmission-related revenues, and distribution-O&M-related revenues. PURA §36.210(a) provides that the DCRF is to be based on changes in the electric utility's distribution invested capital. In light of this requirement, PURA §36.210(a)(2) can reasonably be interpreted as limited to revenues related to distribution invested capital.

Rate Moderation

Oncor Cities recommended that the commission consider adding a provision that allows the presiding judge, upon a showing of good cause, to apply rate moderation constraints to the class allocation in order to avoid excessive cost increases for particular classes. Oncor Cities noted that the commission has historically used rate moderation constraints to avoid excessive class impacts, and based upon the commission's inherent authority to ensure just

and reasonable rates, the rule should permit the exercise of discretion as necessary to prevent unreasonable results for particular classes. Oncor Cities submitted that this would resolve any concerns that the DCRF's formula could result in extreme class impacts by allowing the commission to exercise discretion to modify class results if those situations arise.

Commission Response

Permitting rate moderation adjustments is unnecessary, because the DCRF will make up only a small part of a customer's bill and the DCRF formula is consistent with the principle of cost causation. In addition, allowing rate moderation adjustments, which are fact-specific, would potentially add significant complexity to a DCRF proceeding. The small benefit of permitting a rate moderation adjustment is outweighed by the complexity that it would introduce into a DCRF proceeding.

Absence of Formula Inputs

State Agencies commented that much of the data essential to the proposed formula will not exist when there has been a black box settlement of the previous rate case. Stage Agencies stated that the proposed formula requires various cost data that are to be derived from the utility's last base-rate case, but that much of the required data may not be available because of the wide use of black box settlements. State Agencies commented that many of these black box settlements did not have commission-approved, class-specific cost amounts that can be ascertained for items such as federal income taxes, other taxes, depreciation, and return on invested capital for each class needed to perform the calculations for the formula. Stage Agencies commented that the proposed rule fails to propose a mechanism for dealing with such black box rate case settlements.

OPC expressed similar concerns and recommended that the commission add a provision to the DCRF rule that requires the utility, before applying for its first DCRF, to apply for and obtain a commission determination of the unknown DCRF formula inputs for the utility. OPC stated that the only other alternative would be a new base-rate case for the utility. OPC commented that the proceeding for determination of the unknown DCRF formula inputs must be a contested case proceeding because it will be a part of the DCRF ratemaking process.

SPS commented in response that it plans to file and conclude a base-rate proceeding before considering filing for a DCRF. SPS stated that even if some of the utilities would be unable to take advantage of the proposed rule until after completing a base rate case, it is still advantageous to adopt the rule.

Electric Utilities agreed with SPS that the commission should reject OPC's suggestion that contested-case proceedings should be required to establish DCRF formula inputs for each settled rate case as contrary to the statute and fundamentally inconsistent with its purpose. Electric Utilities stated that while OPC lists five utilities for which it believes at least some of the necessary inputs for the DCRF formula are not available, Electric Utilities do not share OPC's or the State Agencies' concerns because the statute grants the commission discretion on how the incremental distribution investment and the related costs are to be determined. Electric Utilities stated that, with regard to the allocation of costs for the DCRF, all that the statute requires is that it be determined "consistent with the manner in which costs for invested capital...were allocated to each rate class, as approved by the commission," in the utility's

most recent comprehensive base-rate case. Because each settlement and the current circumstances faced by each utility are unique, Electric Utilities addressed the concerns separately for each utility as follows:

Texas-New Mexico Power Company (TNMP) submitted that all of the inputs can be determined from the settlement documents and supporting workpapers from its last comprehensive base-rate proceeding. TNMP filed separate reply comments on this issue that explains its position in detail.

Entergy Texas, Inc. (ETI) submitted that, while not conceding any merit to OPC's claim, the issue can be resolved by scaling the utility's last filed base-rate revenue requirement to the settlement-level revenue requirement. The first step would be to apply any items actually stated in the settlement (*e.g.*, rate of return on equity) to the utility's last filed cost of service study to derive a "base" revenue requirement starting point. The next step would be to compare that base revenue requirement to the settlement revenue requirement for any rate class. The resulting difference, stated as a percentage, would be applied to discrete items in the base revenue requirement to derive the proxy for that item based on the settlement level revenue requirement.

El Paso Electric Company (EPE) stated its belief that, because of the recent completion of one combined-cycle generating unit and the construction of a new combustion turbine, which have not been included in base rates, it does not anticipate it will request a DCRF before filing a comprehensive base-rate proceeding. EPE stated that, consequently, when it requests a

DCRF, the required inputs for the DCRF formula will be available. EPE stated that, in the unlikely event EPE does seek a DCRF prior to another comprehensive base-rate proceeding, it submits that, like ETI, while not conceding any merit to OPC's claim, the issue can be resolved by scaling the utility's last filed base-rate revenue requirement to the settlement-level revenue requirement.

Southwestern Electric Power Company (SWEPCO) stated that it plans on filing and concluding a comprehensive base-rate proceeding prior to the time it would consider filing for a DCRF. Consequently, when SWEPCO request a DCRF, the required inputs for the DCRF formula will be available.

Electric Utilities expressed the position that, after considering these individual replies, the commission can reject the concerns of OPC and State Agencies and adopt the proposed rule, but that in any event, the commission should reject OPC's suggestion that utilities with settled rate cases must litigate a contested case to determine allegedly missing DCRF formula factors before seeking a DCRF. Electric Utilities stated that nothing in the statute contemplates a rule that would effectively penalize utilities that have achieved a negotiated resolution of their most recent rate case. Electric Utilities stated that, in sum, the proposed rule requires no modification to address a supposed gap between the DCRF formula and the data available from utilities who settled their most recent base-rate cases. Electric Utilities commented that the data need only be reasonably derived from the settlement and consistent with the cost allocation approved in the settlement. Electric Utilities submitted that these data are available and can be elicited and appropriately reviewed in DCRF proceedings.

TNMP commented separately on OPC's and State Agencies' suggestion that the proposed DCRF formula requires data that will not be available for utilities that have resolved their last comprehensive base-rate proceeding by a "black box settlement." TNMP stated that all the DCRF formula components that refer to the utility's "last comprehensive base-rate proceeding" can be directly identified in, or readily derived from, the settlement stipulation approved by the commission in TNMP's most recent base-rate case, Docket Number 38480, and that no change to the formula is warranted. TNMP argued that, in all events, OPC's suggestion that utilities who have settled their most recent comprehensive base-rate case should be required to conduct contested-case proceedings to establish DCRF formula inputs, as a prerequisite to applying for a DCRF, must be rejected as contrary to the statute and fundamentally inconsistent with its purpose.

TNMP asserted that, in its most recent comprehensive base-rate case, all the formula inputs, if not found directly in the utility's approved settlement documents, can be determined "consistent with the manner in which costs for invested capital...were allocated to each rate class, as approved by the commission." TNMP stated that is what the statute requires, and the proposed rule requires no more, and that all these DCRF factors are specifically set out in the commission-approved settlement resolving TNMP's case, with the class-specific amounts to be used in the DCRF formula readily available.

TNMP stated that nothing in the statute authorizes a rule that would limit use of DCRFs to utilities with contested-case orders or with settlements that specifically set out each of these

values. Rather, the statute requires, and the rule allows for, determination of class-specific amounts “consistent with” the class allocations applied in the most recent comprehensive base-rate case, whether it was resolved by settlement or order. TNMP stated that, in its recent case, the settlement Stipulation included agreement “on the allocation of the base rate increase as reflected in the schedule attached hereto and incorporated by reference in Appendix B.” The Stipulation continued that “Exhibit B is provided for the limited purpose of defining the agreed class allocations and the total dollars allocated to each class.” TNMP commented that the commission’s Final Order approving the settlement recognized that the parties had agreed that the base-rate increase would be “allocated and implemented through the customer class allocations shown on Exhibit B to the stipulation.” Exhibit B to the Stipulation spreads the agreed Texas retail cost of service across the several rate classes. TNMP asserted that all the necessary calculations for determining the formula’s inputs are shown in TNMP workpapers, and these workpapers are straightforward, subject to independent replication, and available and subject to review in a DCRF proceeding, and these calculations include class-specific allocations for all the categories required under the DCRF formula. TNMP provided copies of schedules from its last rate case affirming these points.

TNMP commented that OPC’s suggestion that utilities who have settled their most recent rate case should be required to litigate a contested case to determine allegedly missing DCRF formula factors, before they can seek a DCRF, is an outlier proposal that would stand on its head a statute designed to streamline ratemaking. TNMP commented that nothing in the statute contemplates or authorizes a rule that would limit the DCRF in this fashion, which would effectively penalize utilities that have achieved a negotiated resolution of their most recent rate case. Such a rule

would be extraordinarily bad policy — discouraging the settlement of comprehensive base-rate cases — and it would run contrary to the statute, which makes no mention of the new species of contested cases proposed by OPC and requires only that the adjustment be consistent with the cost allocation approved in the utility's most recent rate case. TNMP stated that the proposed rule does not require use of data that is unavailable to utilities who have settled their most recent rate case, at least as long as the rule comes with a clear directive from the commission that it be interpreted and applied reasonably, as outlined above.

Commission Response

The commission disagrees with OPC that, before an electric utility with a settled comprehensive base-rate proceeding applies for a DCRF, a contested-case proceeding should be required to establish DCRF formula inputs. Such a requirement would be inconsistent with PURA §36.210(a)(1)'s requirement that a DCRF be approved or denied in accordance with an expedited procedure. The commission has added a provision to subsection (d)(1) that states that, if an input to the DCRF formula from the last comprehensive base-rate proceeding is not separately identified in that proceeding, it shall be derived from information from that proceeding.

Section 25.243(d)(2): Return on Invested Capital

Electric Utilities contended that the rule's requirement that 10% be used as an alternative to a utility's commission-approved return on equity (ROE) that is over three years old and greater than 10% should also apply to commission-approved equity costs that are less than 10%.

Electric Utilities further suggested that rather than 10%, the alternative ROE should be determined as an average of the last three ROEs approved by the commission.

CEP, COH, State Agencies, CORE, Oncor Cities, OPC, and TIEC all disagreed with Electric Utilities. CEP stated that the commission should reject Electric Utilities' suggested change to 10% rate of return because it makes the alternative more arbitrary. The suggested change does not consider the scope of operations, size, or capital structure of the companies whose rates of return it would have as proxies for the filing company, nor does it consider the timing of the comparable companies' rate cases, if the companies are subject to any special circumstances, whether they have a decoupling mechanism, and other factors. CEP also commented that the return on invested capital provisions of the proposed rule rely excessively on prior decisions of the commission and on reports that the commission requires to be filed by an electric utility. In CEP's case, this could have resulted in a cost of debt that was almost three years old. CEP stated that the rule should require references to a more-current, embedded cost of debt and capital structure.

COH asserted that the proposed rule's provisions for determining return on invested capital should be retained without change because a utility is required by its fiduciary duty to apply for an increase in rates whenever it is not being fully compensated for its cost of service. Further, a utility's not filing a rate case for three years in most cases would be a reliable indication that the utility has determined its ROE is equal to or lower than the lower of 10% or the last ROE approved for it by the commission. COH commented that this approach is especially appropriate

in regard to the DCRF rule, because the rule will promote timely recovery of costs, a factor which would lower ROE.

COH also disagreed with Electric Utilities that the 10% ROE is arbitrary and unlikely to represent an appropriate ROE over time, because 10% is supported by the commission's recently allowed ROEs. The commission authorized CenterPoint and TNMP ROEs of 10% and 10.13% respectively in their most recent rate cases. COH commented that the 10% allowance for ROE is also supported by the 9.80% average ROE for electric-delivery service allowed by state commissions during the first half of this year. COH further pointed out that the difference between this last 9.80% average and 10.24%, which is the allowed average ROE for *all* electric utilities during the same period, is 44 basis points. Subtracting 44 basis points from 10.40%, the average ROE allowed for *all* electric utilities from 2005 through June 2011, results in a ROE of 9.96% for *electric-delivery* companies. COH contended that future economic activity and capital costs are generally expected to be comparable to or lower than those prior to 2005, which would make the 10% ROE unlikely to be too low an approximation of the cost of common equity capital for electric distribution service in the future.

State Agencies contended that the averaging approach proposed by Electric Utilities would not be appropriate because it would rely on approved ROEs that could be older than five years. State Agencies expressed the belief that the Legislature implied five years would be an acceptable interval between rate cases before information would need to be updated in a base-rate case. State Agencies recommended that any utility seeking its initial DCRF must have had its ROE in a base-rate case determined by the commission within a certain period of time before making

that request in order that the process of updating avoid the “moving target” aspect of adjustment requests filed more than three years after the prior rate decision. In the case of the proposed rule, State Agencies recommended the five-year time period it believes is supported by statute.

CORE disagreed with Electric Utilities that averaging the last three ROEs approved by the commission in base-rate proceedings would result in an appropriate determination of a utility’s ROE for calculating a DCRF, because the number of separate tariffs a utility may file to increase various rates between base-rate cases makes it questionable how often utilities will file base-rate cases. CORE also advised that the ROEs approved by the commission are inappropriate for the proposed rule because they are utility-specific, and averaging three of them does not sufficiently mitigate the utility-specific aspect to make the average accurate for the rule’s purpose.

Oncor Cities maintained that ratepayers should be given the benefit of a previously authorized rate of return that is below the rule’s alternative rate of return because a utility’s authorized rate of return is specific to that utility and may recognize more favorable risk factors appropriate for that utility. Oncor Cities further held that Electric Utilities’ proposed change may create a loophole whereby utilities could recover additional distribution costs at a higher rate of return than the rate of return used to determine excess earnings in the earnings monitoring report. Oncor Cities stated that Electric Utilities’ proposal to use the average cost of equity adopted by the commission in the previous three electric-utility base-rate cases is susceptible to misuse and should be denied in favor of provisions of the proposed rule. Oncor Cities opined

that misuse of Electric Utilities' proposal may occur because one of the three previous comprehensive base-rate cases were associated with utilities that were not comparable to the utility filing the DCRF application or because the cases were settled without an explicit ROE or with terms limiting their applicability as precedent. Excluding settled cases could result in inappropriately old rate case decisions being part of the average. Oncor Cities also stated that, if the three utilities used to develop an average rate of return are themselves subject to the alternative return, there would be illogical results and that the required rates of return of electric utilities should be recognized as lower after the rule goes into effect because all current authorized rates of return incorporate investors' assumptions that an electric utility in Texas cannot obtain rate recovery for new distribution investment until a final order is entered in the utility's next full base-rate case.

TIEC supported the comments by Oncor Cities, noting that the reduction to utilities' risk actually occurs at the time they are able to implement a DCRF, which is prior to the time their reduced risk would be considered in a base-rate proceeding. Given this dynamic, TIEC expressed its support for Oncor Cities' proposal to impose a presumed 25 basis point reduction to the utilities' rates of return and Oncor Cities' proposed changes to §25.243(d)(2).

Walmart cited other jurisdictions that have made specific ROE adjustments to recognize the effects of implementation of revenue assurance mechanisms: Maryland Public Service Commission reduced Potomac Edison's ROE by 50 basis points; Montana Public Service Commission reduced NorthWestern Energy's ROE by 25 basis points; and the Public Utility Commission of Oregon reduced Portland General Electric ROE by 10 basis points.

Walmart also cited several state commissions that have accounted for revenue assurance mechanisms in setting the utility's ROE but did not provide a specific adjustment in their orders. Walmart commented that the rule's methodology for setting the rate of return for an electric utility whose rate of return was approved more than three years before the DCRF application should be required for all DCRF applications. Walmart contended that this would recognize the revenue assurance and risk reduction provided by implementation of the DCRF.

OPC stated its belief that the alternative method in the proposed rule clearly recognizes that rates of return have decreased over recent history, is a more reasoned approach than that suggested by Electric Utilities, and is a good compromise among the various parties' positions. OPC commented that a proceeding to establish rate of return may be necessary if a utility has no authorized rate of return. CEP opined that OPC's recommendation has merit because, although proposed rule is a reasonable compromise in circumstances in which no rate-case finding has occurred for some period of time, it is often true that there has been no recent rate-case decision upon which to establish the rate of return. CEP also commented that earnings reports do not always reflect a company's current capital structure and cost of debt.

Electric Utilities maintained that the State Agencies' concern about possible uncertainty about the information needed to ascertain the rate of return under Electric Utilities' alternative return proposal is misplaced because the information is readily available and can be easily applied. Electric Utilities advised that the State Agencies' recommendation that the commission require utilities seeking their initial DCRF to have had their ROEs determined in a comprehensive base-

rate case should be rejected if the State Agencies mean a litigated outcome, as it is in the interest of the commission, the parties, and ratepayers for parties to settle cases when possible. Electric Utilities also contended that a comprehensive base-rate case, litigated or settled, is not necessary for a utility to qualify for a DCRF because the alternative rate of return in the rule ensures that utilities cannot continue to use rates of return that may have grown stale with the passage of time.

Electric Utilities stated that Walmart does not provide adequate support for its recommendation that the commission adopt the alternative proposal in the rule for all DCRF applications, regardless of how recently the commission approved the utility's rate of return. Electric Utilities submitted that Walmart had not adequately demonstrated that the circumstances of the decisions it cites in other jurisdictions that have reduced a utility's ROR for the effects of "revenue assurance programs" are comparable to the circumstances in which the proposed rule is to be applied. Electric Utilities also commented that Walmart provided no reason to believe that the alternative rate of return proposed in the rule is a better proxy for a utility's required return than a recent rate of return awarded by the commission.

Commission Response

The commission declines Electric Utilities' recommendation to use an average of the last three ROEs approved by the commission. CEP, CORE, and Oncor Cities all correctly pointed out that the averaging method favored by Electric Utilities has no provision for ensuring comparability between the utility whose ROE is being determined and the utilities used in the averaging. In addition, the commission declines Electric Utilities' proposal to use the alternative rate of return even when it is higher than an electric utility's rate of

return that was approved in its last comprehensive base-rate proceeding. This proposal would risk allowing the utility to over-earn. In contrast, if the alternative rate of return is lower than the utility could demonstrate, it has the right to initiate a comprehensive base-rate proceeding in which its rate of return would be re-determined.

The commission disagrees with CEP's request to use more current, embedded cost of debt and capital structure. Using the capital structure approved by the commission in the electric utility's last comprehensive base-rate proceeding is appropriate, because the commission determined that the capital structure was reasonable, and the utility's capital structure is unlikely to change much over time. An electric utility's cost of debt is rarely an issue, so using its cost of debt as reported in the electric utility's most recent earnings monitoring report is appropriate.

For the reasons discussed below concerning subsection (g), the commission declines the suggestions of Walmart, Oncor Cities, and TIEC to impose a specific ROE adjustment to recognize the effects of implementation of a DCRF.

Section 25.243(e)(1): Procedures for DCRF or DCRF Update Proceeding—Filing Requirements

CORE commented that in addition to a sworn statement by an employee of an electric utility filing an application for a DCRF filing, the electric utility should be required to provide supporting documentation with its initial filing. CORE requested that the electric utility be required to also file schedules and supporting workpapers in their native, electronic, and

searchable format sufficient to support the electric utility's application, as well as its more recent earnings monitoring report, updated to within 90 days of the filing to allow parties to more quickly and efficiently review an application and to demonstrate that the electric utility's application should be denied pursuant to subsection (e)(4).

Commission Response

Subsection (e)(1) lists the requirements in PURA §36.110 for a DCRF application and requires use of the commission-prescribed application form. The commission is developing the DCRF application form in Project Number 39466, and will address in that project issues concerning what information must be included in a DCRF application. As discussed above concerning subsection (b)(3), the commission has changed subsection (e)(1) to require that the sworn statement included with a DCRF application expressly state that the costs included in the DCRF comply with PURA §36.058. The commission has also required that the statement expressly state that the costs comply with PURA §36.053 and, as discussed below concerning subsection (e)(5), expressly state that the costs are prudent, reasonable, and necessary. As discussed below concerning subsection (e)(4), the commission has also added to subsection (e)(1) a requirement that an electric utility include in its application an earnings monitoring report for the immediately preceding calendar year prepared in accordance with §25.37(b) of this title.

Section 25.243(e)(2): Notice and Intervention Deadline

CORE submitted that the proposed rule's requirement for an electric utility to provide notice of an application for a DCRF filing to all parties in its last comprehensive base-rate proceeding, and

if applicable, last DCRF update or DCRF update proceeding, by the day after it files its application, is not sufficient, both in manner of service and the identified recipients. CORE stated that the rule should specify that notice must be mailed to all parties in the electric utility's last base-rate proceeding or DCRF proceeding to ensure parties can know how notice will be provided and the commission can determine when service was completed; additionally, the rule should also require notice of the proceeding before the commission, including the docket number for the new proceeding, to be mailed to all municipalities in the electric utility's service territory at least two weeks (14 days) prior to the electric utility's DCRF filing. CORE stated that early provision of notice to all municipalities within the electric utility's service area, similar to early notice provided to municipalities in a general major rate case, will notify municipalities exercising original jurisdiction of the docket in which the application before the commission was filed and will allow all municipalities to take the necessary steps to timely intervene in the proceeding.

Electric Utilities replied that CORE's requests that notice be provided by mail and that the municipal authorities be provided 14 days' advance notice of the filing should be rejected. Electric Utilities pointed to CORE's comment concerning the need that notice be given by mail "to ensure parties can know how notice will be provided and the commission can determine when service was completed," and replied that it is not clear why it is necessary for parties to know how they will receive notice. Likewise, Electric Utilities commented that they routinely provide proof of notice and are unaware of any particular controversy regarding establishing the timing of when notice was served. Electric Utilities noted that given that these proceedings are intended to be expedited, rather than restricting notice to a centuries-old method that requires the

use of paper, the rule should provide flexibility and allow notice of the filing to be given by email, which is widely used for conducting business. Electric Utilities noted that in some places, the commission rules already recognize this—for instance, the rule for revision of a fuel factor pursuant to a formula requires that a copy of the filing be served by email. Electric Utilities commented that CORE’s suggestion that municipalities be notified 14 days in advance of a filing so that the municipalities can “take the necessary steps to timely intervene in the proceeding,” is unnecessary and adds an unnecessary additional burden to a DCRF filing. Electric Utilities stated that the circumstances that call for the advance notice in a general rate proceeding do not exist with a DCRF filing, given that in a general rate proceeding, once the advance notice is given, the municipality has 30 days to elect to receive a copy of the statement of intent, and the utility is required to provide the statement of intent to only those municipalities that request one. Because the statement of intent in a general rate proceeding is typically a very large filing comprising several file boxes, the advance notice/municipal election process avoids the wasteful process of providing boxes of information to municipalities that do not want them. Electric Utilities noted that the DCRF filing will be much more abbreviated, so it is unnecessary to go through this additional step. Electric Utilities stated that providing notice by the day after the filing, as required by the proposed rule, should be more than adequate to allow the municipality to take the necessary steps to intervene in the PUC’s proceeding.

Commission Response

The commission declines to make any changes. The rule should permit reasonable methods of notice that are more efficient than first-class mail. In addition, requiring advance notice to cities would place an unnecessary burden on an electric utility. If a city

was a party in the electric utility's last comprehensive base-rate proceeding or DCRF proceeding, it will receive notice at the same time as the other parties in those proceedings. If a city exercises original jurisdiction over the utility's rates, the utility will file its DCRF application with the city at the same time that it files with the commission.

Section 25.243(e)(4): Denial Due to Earnings

COH recommended, and OPC and CORE agreed, that the rule should clearly indicate that the commission correction to the rate of return is to the earned rate of return rather than the allowed rate of return. To that end, COH provided amended rule language consistent with its recommendation.

TIEC, CORE, COH, OPC, and Oncor Cities indicated support for an improved earnings monitoring report (EMR) and process, and up-to-date reports to support DCRF updates. TIEC stated that it does not believe that the currently instituted EMRs provide an adequate tool for assessing a utility's current revenues. TIEC therefore recommended, and CORE agreed, that the commission make clear that a substantially revised and enhanced earnings monitoring process is needed. TIEC suggested that the reduced frequency of base-rate cases and the cost recovery contemplated in this rule will make the earnings monitoring process more critical to ensuring that utilities are not over-recovering. CORE suggested that the rule must contain all necessary provisions to ensure that an up-to-date EMR is available to assess whether the electric utility is earning more than its authorized rate of return at the time that it files its DCRF filing. To that end, CORE recommended that the rule specify that commission consideration of an electric utility's DCRF filing is contingent upon the filing of an updated EMR within 90 days of the

DCRF filing. CORE provided redlined rule language consistent with its recommendation, which TIEC supported. Oncor Cities argued, and CORE agreed, that the usefulness of the EMR as a guide to whether the utility is overearning is significantly impaired unless the report is filed in conjunction with the DCRF application. Oncor Cities recommended rule language that requires utilities to file their EMRs in conjunction with their April DCRF application to the extent they do not already have an EMR on file for the year ending December 31 prior to the April DCRF filing. TIEC indicated support for both the CORE and Oncor Cities' approaches. OPC indicated support for Oncor Cities' approach.

Electric Utilities recommended, and OPC agreed, that the proposed rule make clear that the EMR shall not be litigated in the DCRF proceeding. Electric Utilities argued that litigation of the EMRs would transform DCRF proceedings into comprehensive base-rate proceedings and would prevent the commission from processing an application in an efficient manner as required by statute. Electric Utilities explained further that combining the review of the EMR with the review of the DCRF creates the potential for abuse, considerable uncertainty, and cost to consumers. Electric Utilities proposed language consistent with these points.

CEP, Oncor Cities, COH, TIEC, and CORE recommended that the commission reject Electric Utilities' proposal to revise language relating to the EMR to reflect that the EMR is not subject to review in a DCRF proceeding. CEP argued that the report must be subject to some review because the report may reflect issues that are not considered in the ratemaking process (*e.g.*, expenses which may be disallowed for ratemaking purposes, or non-recurring expenses or charges). Oncor Cities pointed to PURA §36.210(g)(4), which requires the "denial of the

electric utility's filing if the electric utility is earning more than the utility's authorized rate of return on investment...at the time the periodic rate adjustment request is filed." Oncor Cities noted that Electric Utilities propose to bar any review of their EMRs in their DCRF cases without explaining how the resulting process will ensure that utilities are not over-earning "at the time the periodic rate adjustment request is filed" in accordance with the statute. Oncor Cities reiterated that parties must be able to review Electric Utilities' EMRs and to propose adjustments as necessary. Oncor Cities believed that the proposed rule already includes constraints that are intended to restrain litigation in a DCRF filing, including discovery limitations and a short timeline for approval, and that such limitations will not significantly burden a DCRF filing. COH stated that the Legislature recognized the importance of the EMR as a tool in the DCRF process, and clearly indicated that the utility's DCRF application must be rejected if the utility is over-earning as measured by a valid EMR. CORE disagreed with the recommendation by Electric Utilities to preclude review of a utility's EMR in a DCRF filing because it would restrict the commission's ability to ensure that a utility is not earning more than its authorized rate of return at the time of filing a DCRF, consistent with PURA §36.210(g)(3) and (4). TIEC argued that because the EMRs will be used to determine whether a utility can implement a DCRF, parties must be given an opportunity to vet utilities' EMRs and to ask discovery regarding the assumptions that go into those reports.

OPC disagreed with CEP, Oncor Cities, COH, and CORE that an evaluation of the EMR should be included in a DCRF case.

Electric Utilities disagreed with several parties that urged the commission to address issues related to the EMR that will be used to determine whether a utility is over-earning. Electric Utilities stated their belief that the commission is currently planning to revise the language of §25.73, the rule that governs EMRs; therefore, Electric Utilities argued that the commission should defer consideration of any changes to the EMR filing requirements in this proceeding and address those issues in the EMR rulemaking. Electric Utilities opined that revising the EMR requirements on a piecemeal basis in different rulemaking projects may lead to inconsistent requirements and unintended consequences. OPC agreed with Electric Utilities that suggested improvements to the EMR process should be handled outside this DCRF rulemaking proceeding in a comprehensive review of the EMR requirements under §25.73(b).

State Agencies argued that restricting the commission from reviewing an EMR where it may be appropriate is ill-advised because the commission has the duty to review a previously approved DCRF not just for prudence and reasonableness of the underlying costs, but to refund any amounts that were “improperly recovered” through the DCRF. State Agencies believed that such commission oversight would not equate to re-litigation of the EMR.

State Agencies, CORE, and OPC concluded that an electric utility that intends to seek a DCRF should not be entitled to a waiver of the requirement to file an EMR because the EMR is critical to the assessment of a utility’s qualification for a DCRF.

COH suggested rule language that expressly extends to a municipality the authority to deny a DCRF application due to over-earnings.

Commission Response

PURA §36.210(g)(4) requires that the commission deny a DCRF application if the electric utility is earning more than its authorized rate of return at the time the application is filed. Thus, determining whether the utility is over-earning is a key issue with respect to a DCRF. Therefore, parties in the DCRF proceeding should be allowed to participate in that determination.

PURA §36.210(g)(3) contemplates that the commission will use an EMR to make this determination. As a result, the commission has added to subsection (e)(1) a requirement that an electric utility include in its DCRF application an EMR for the immediately preceding calendar year prepared in accordance with §25.37(b) of this title.

The commission agrees with COH, OPC, and CORE that the rule should clearly indicate that the commission's correction of the rate of return in the EMR is to the earned rate of return rather than the allowed rate of return, and changes the rule accordingly.

The commission agrees with TIEC, CORE, COH, OPC, and Oncon Cities that the EMR form and process should be updated. The commission has opened Project Number 39040 for this purpose.

The commission declines COH's recommendation to expressly extend to a city the authority to deny a DCRF application due to over-earnings. PURA §33.004(b) states that a

city may exercise the same regulatory power under the same standards and rules as the commission.

Section 25.243(e)(5): Scope of Proceeding

Electric Utilities, COH, and TIEC commented on the scope of the DCRF proceeding and voiced concern over the language in the proposed rule that allows the prudence of a particular cost to be examined in a DCRF proceeding “for good cause.” Electric Utilities submitted that in order to ensure a timely and efficient process, the rule should not allow parties to expand the scope of a DCRF proceeding by litigating the reasonableness of the investment in the DCRF proceeding. They argued that reconciliation of the distribution investment should mirror the TCOS process and take place in the utility’s next comprehensive base-rate proceeding, stating that the portion of the proposed rule that would allow the presiding office to transform a DCRF proceeding into a prudence review creates the potential for abuse, considerable uncertainty, and cost to consumers. In addition, Electric Utilities contended that opening the DCRF proceeding up to a review of prudence would necessarily mean that electric utilities would be required to develop testimony on the prudence issues raised, which would necessarily lengthen the DCRF process and jeopardize the expedited timeline. COH agreed that the good cause exception makes the scope of the proceeding uncertain and could result in additional complexity that is beyond the scope of limited proceedings to address. Both Electric Utilities and COH proposed that the portion of the proposed §25.243(e)(5) after the word “update” be deleted.

TIEC commented that given the abbreviated time frame and discovery procedures contemplated for the DCRF, it supported reserving prudence review until the utility’s next base-rate

proceeding. TIEC stated concern that subsection (e)(5) opens the door to allowing utilities to seek prudence review of a particular cost under the truncated DCRF procedures and bypass the more rigorous review that would occur in a rate proceeding. TIEC recommended that subsection (e)(5) be clarified to allow prudence review for a particular cost only upon request by a *non-utility* party to the proceeding. Additionally, TIEC stated that if the presiding officer allows prudence review for good cause, the discovery limitations in subsection (e)(6)(B) should no longer apply given the expanded issues.

Electric Utilities commented that TIEC's proposal to modify this section to allow the scope to be expanded only upon the request of a non-utility is an unworkable proposal and should be rejected. Electric Utilities argued that an electric utility needs to know before the filing whether it will be expected to present evidence and testimony to support the prudence, reasonableness, and necessity of its costs. If the electric utility will be at risk in each case of the scope being expanded, necessarily the electric utility will have to make it a routine practice to address, prudence, reasonableness, and necessity in every filing, and this will increase the costs, diminish the efficiency of the process, and ultimately result in greater costs to the customers.

OPC agreed that litigating whether requested additions to distribution invested capital are prudent, reasonable, and necessary in a DCRF case complicates the case and could interfere with the processing of the DCRF application within the time period contemplated in the proposed rule. OPC recommended that the commission remove consideration of whether requested additions to distribution invested capital are prudent, reasonable, and necessary from the scope of the DCRF case and reserve these issues to the utility's forthcoming base-rate case. OPC

contended, however, if the commission should decide to allow litigation of these issues in a DCRF case, then the commission should revise subsection (e)(5) of the rule to allow these issue to be litigated in a DCRF case only if a non-utility party in the case requests that the issues be litigated in the DCRF case and shows good-cause for doing so, as TIEC recommended. OPC further argued that if the prudence issues are litigated in a DCRF case, OPC urges the commission to remove the discovery limitations in subsection §25.243(e)(6)(B), at least in regard to the particular DCRF case due to the expansion of the issues to be litigated. CORE agreed with Electric Utilities and COH and recommended that no “good cause” exception be included in the rule in order to provide certainty as to the scope of the proceeding. However at a minimum, CORE stated that TIEC’s proposed revisions should be accepted.

Commission Response

The commission has retained the good-cause exception for a reconciliation in a DCRF proceeding. The commission expects to use this provision rarely, if ever. However, there could be a circumstance, for example, where the commission is sufficiently concerned about an electric utility’s actions related to distribution invested capital that it feels the need to review those actions before allowing recovery of the invested capital. Under the rule, such a review is allowed only if the presiding officer finds that good cause exists to do so. In such a case, the utility would be given time to prepare direct testimony addressing the issue and good cause would exist to allow additional discovery and extend the timeline for the proceeding. The commission has also changed subsection (e)(1) to require that the sworn statement included with a DCRF application expressly state that the costs included in the DCRF are prudent, reasonable, and necessary.

Section 25.243(e)(6)(B): Discovery

Electric Utilities supported the commission's streamlining the DCRF process by placing parameters on discovery, because the proposed parameters are consistent with PURA §36.210(g)(2), regarding the adoption of rules that expedite procedure; they are commensurate with limiting the scope of the process; and, they prevent unnecessary expense and burden on the commission of processing a DCRF rate change. Electric Utilities contended that by specifically requiring the commission to adopt a rule providing for “discovery consistent with the expedited procedure,” it is clear that the Legislature intends the commission to adopt some type of limitation on discovery. Electric Utilities maintained that the limit of 20 requests for information should apply to all questions, including objectionable requests, and it should also be made clear that if an objection to a request for information is sustained that does not mean the party can make an additional request.

CEP advised that Electric Utilities’ restrictions for the proposed rule are too stringent and that the rule’s provision that questions for which an objection is filed should not be counted should remain. CEP stated that the number of discovery questions per party including subparts needs to be expanded substantially. CEP pointed out that parties may seek limitations on discovery from the presiding officer and advised that depositions should be permitted as they are in other cases.

OPC, CORE, and State Agencies contended that the rule should specify that a discovery request to which an objection is filed or a motion to compel because the utility’s answer is non-responsive is filed does not count against a party’s request limit. Oncor Cities maintained that, if

these requests for information (RFIs) count against whatever RFI limit the commission may adopt, Electric Utilities will have every incentive to object as widely and often as possible in the hope that some of the objections have merit. Oncor Cities submitted that such an incentive is inconsistent with an expedited procedure, and recommended that the commission reject Electric Utilities' recommendation on this point.

Oncor Cities stated that a limitation of 50 RFIs and requests for admission would be more meaningful than 20, which the proposed rule would allow. A limitation of 20 would encourage insufficient or ambiguous answers, which would be safe from full follow-up discovery. Oncor Cities additionally stated that requests for more discovery would likely be opposed, which would consume limited time for evaluating the utility's application and that limiting RFIs and requests for admission to 20 could render the discovery process futile, which would be inconsistent with the specific provision for discovery in a DCRF/DCRF update proceeding made by PURA §36.210(g)(2). COH made similar comments.

State Agencies contended that the proposed rule imposes limits on the number and form of RFIs that are unnecessary and premature. State Agencies commented that if the rule is to depart from existing discovery practice, it should address discovery abuse by utilities as well as by other parties. State Agencies agreed that commission staff should not be limited in any further information it seeks from the electric utility, and proposed a separate section of the rule be added to emphasize this. State Agencies recommended that failure of the electric utility to make full disclosure of requested information should be grounds for denying the DCRF request in whole or in part.

State Agencies maintained that there is no indication that other states that have interim rate recovery mechanisms in place have found it necessary to so restrictively limit discovery by rule. State Agencies recommended that the commission consider that limiting the number and structure of discovery requests undercuts the statutory directive to foster public participation and that there are already rules in place should discovery become abusive or duplicative. State Agencies also advocated the elimination of voluminous rooms and remote availability of information because PURA §36.210 proceedings are expedited and current technology for production of requested information can make its acquisition faster.

CORE disagreed with the proposed rule's limitation of the number of discovery requests because it is still unknown what information an electric utility will provide with its initial filing. CORE also recommended that the commission keep in mind that the absence of a prudence review already reduces the need for discovery, any discovery limitation that is imposed should not preclude the inclusion of subparts or multiple questions, and there should be no limitation of requests for production because they would only be necessary if the electric utility does not properly document its requested rate change.

OPC maintained that expediting the DCRF cases by limiting the principal form of discovery for intervenors is not consistent with the Legislature's intent in Senate Bill 1693, and the amount of discovery that can be conducted is already indirectly limited by the time limitation of an expedited proceeding. OPC did not consider commission staff's argument citing limitations placed on interrogatories in the federal rules as similar to those of this proposed rule as appropriate

because the principal method of discovery under the federal rules is depositions and, in cases before the commission, requests for information and admissions are the principal forms of discovery for intervening parties, which have limited budgets. OPC also commented that technical conferences are useful but are inadequate substitutions for requests for information and admission because submitting information acquired through technical conferences as evidence is cumbersome.

Walmart maintained that the proposed discovery limits severely limit the ability of parties other than staff to contribute to the development of a robust and transparent examination and complete record.

Electric Utilities disagreed with State Agencies that it is bad public policy to impose numerical restrictions on discovery questions, because the State of Texas has had discovery limitations in civil suits in place for years. Electric Utilities responded to various commenters' objections to the proposed rule's policy about question subparts by noting that Texas rules of civil procedure specifically state that "[e]ach discrete subpart of an interrogatory is considered a separate interrogatory." Similarly, Electric Utilities responded to various commenters' objections to limitations on depositions by noting that limitations on depositions are also found in the Rules of Civil Procedure. Electric Utilities considered the following other factors to be significant in determining whether the rule unnecessarily limits discovery: DCRF revenues would be subject to refund in a subsequent reconciliation proceeding, the proposed rule explicitly allows a single technical conference, staff would not be subject to any discovery limitations, and other parties' could request additional discovery upon a showing of good cause. Electric Utilities provided a

chart that supports the proposed discovery limitations being reasonable by showing that after the first few interim TCOS filings, a process similar to the DCRF filings, the number of intervenors and the number of discovery questions fell to zero.

Electric Utilities also opposed State Agencies' suggestion that the rule provide that voluminous discovery responses be provided on CD or DVD and suggested that the commission not impose additional discovery burdens on utilities in what is designed to be an expedited proceeding.

Commission Response

PURA §36.210(g)(2) requires that the commission adopt a DCRF rule that addresses “discovery consistent with the expedited procedure” required by PURA §36.210(a)(1). This provision contemplates that the DCRF rule will impose discovery limits. The discovery limits in the proposed rule are appropriate because the form for a DCRF application will require that the electric utility include extensive information as part of its application; the scope of a DCRF proceeding is narrow; and the costs recovered through the DCRF will be reconciled in the utility’s next comprehensive base-rate proceeding.

The proposed rule provides that an RFI for which an objection is filed does not count towards a party’s RFI limit. This provision provides appropriate incentives. Because of the expedited timeline for a DCRF proceeding, a utility could significantly impair an intervenor’s ability to conduct appropriate discovery by aggressively objecting to RFIs. Even if the objections were overruled, the RFI responses would be significantly delayed. Not counting objected-to RFIs towards the RFI limits provides a utility an incentive not to

object to RFIs if it is unlikely to prevail on those objections. In addition, an intervener has an incentive not to ask irrelevant RFIs, because those RFIs would count toward the party's RFI limit if the utility does not object to them. In addition, the rule does not limit the number of RFIs from commission staff. Because there is no RFI limit on staff, the commission has changed the rule so that the numbering restrictions do not apply to staff.

With respect to Oncor Cities' concern about insufficient or ambiguous RFI responses, a party propounding RFIs should take care in the drafting of the RFIs to be clear what it is asking for. In addition, the commission expects the parties to work diligently and in good faith to resolve discovery issues. *See* §22.144(d). If necessary, the propounding party can file a motion to compel a sufficient response. The commission declines State Agencies' request that for DCRF proceedings the commission change the manner in which RFI responses are provided; the commission's existing procedural rules adequately address this issue.

Section 25.243(e)(6)(C): Consolidation of Appeals

As discussed above concerning subsection (c)(1), the commission has addressed consolidation of appeals in subsection (c)(1) of the adopted rule. Therefore, the commission has deleted proposed subsection (e)(6)(C).

Section 25.243(e)(6)(D): System-wide Rates and Effective Date of DCRF Filing

COH and CORE took issue with the term "system-wide rates." COH commented that the proposed subsection (e)(6)(D) contains terms that are inconsistent with the subsection heading

reading “system-wide rates,” while the text of the subsection requires the presiding officer to approve a DCRF on a “system-wide basis.” COH argued that because PURA §36.210(a)(5) requires the utility to implement a DCRF on a “system-wide basis,” the reference to “system-wide rates” should be stricken, as it is without basis in the enabling legislation. COH stated that “system-wide rates” and “system-wide basis” are not interchangeable and if the commission equates the two phrases, the result would be a direct conflict with a municipality’s original jurisdiction over rates within its city limits. COH contended that if the commission were to impose a “system-wide rates” rule, it would effectively render the municipality powerless to set a DCRF within its own city limits, and the only valid DCRF would be beyond the city’s jurisdiction to adopt. COH argued that a municipality may not be required to cede its original jurisdiction in conflict with PURA §33.002, and the plain purpose of PURA §36.210 may be accomplished by adopting a rule that allows the municipality to set, and the utility to implement, a DCRF on a “system-wide basis” to the fullest extent of its jurisdiction to do so, and that preserves the ability of the utility and municipality to settle a DCRF on mutually agreeable terms on a “system-wide basis” within the city limits.

CORE agreed, stating that proposed subsection (e)(6)(D) states that the presiding officer shall approve the DCRF “on a system-wide basis,” and, further, the rule requires the electric utility to appeal the local regulatory authority’s final “decision,” regardless of whether the local regulatory authority approved or denied the application. Thus, irrespective of a municipality’s final decision in regard to a DCRF filing, the municipality’s decision will be appealed to the commission, consolidated with the applications already before the commission, and conformed to those applications over which the commission has original jurisdiction. CORE argued that

just as the expedited timeframe for processing the DCRF filings erodes a municipality's right to exclusive original jurisdiction, the rule's required system-wide rates would render null and void any decision by a municipality, including approval or settlement, different from the commission's order in applications already before the commission as the regulatory authority with original jurisdiction. CORE stated that PURA §36.210 does not require system-wide rates, contending that it only requires the use of system-wide data to be used in determining rates, similar to the existing process in base-rate proceedings. CORE stated that system-wide "rates" are not mentioned, much less required by the bill, and therefore the proposed rule would limit a municipality's exclusive original jurisdiction over the rates of an electric utility in its city limits on the commission's own initiative and would be contrary to limits placed on the commission's jurisdiction by §32.002 and §33.001 and new PURA §36.210.

REP Coalition disagreed that the proposed rule's system-wide rate requirement will eliminate the jurisdiction of the local regulatory authority and that this is not required or authorized by PURA §36.210(a)(5). REP Coalition argued that PURA §36.210 requires that the DCRF be applied by an electric utility on a system-wide basis, and the system-wide rate obligation, as implemented in the proposed rule, does not impinge on the jurisdiction of the local regulatory because such obligation does not prevent the local regulatory authority from continuing to review and act upon rate filings made with them. REP Coalition contended that, instead, the proposed rule simply requires the utility to appeal to the commission any DCRF decision made by a municipality with original jurisdiction, and only through the appeal process outlined in the proposed rule can the utility meet its statutory obligation under PURA §36.210(a)(5) to implement the DCRF as a system-wide rate. REP Coalition stated that because the commission has original jurisdiction

over rates that apply in areas outside the city limits of a municipality with original jurisdiction and also has jurisdiction to address appeals of decisions of a municipality's governing body, only the commission can approve a system-wide rate. REP Coalition submitted that by appealing a municipality's governing body's decision to the commission, as required by subsection (c)(1) of the proposed rule, the utility has the opportunity to meet the statutory obligation to apply the DCRF on a system-wide basis. REP Coalition asserted that if this system-wide rate obligation is not met, then the rate cannot go into effect because the terms required by PURA §36.210 for a DCRF would not be met.

REP Coalition additionally commented that system-wide utility rates are essential to enable REP Coalition to maintain consistent pricing plans across a utility's service area and reduce the complexity of the shopping experience for retail electricity customers. If utility rates that apply inside a municipality's city limits were to vary from those rates that apply outside the city limits, there would be a heavy administrative burden on REP Coalition to maintain many additional pricing plans, complicating price disclosure to potential customers. REP Coalition stated that the arguments put forth by CORE and COH to assert that system-wide rates are not required or authorized by SB 1693 are strained and incorrect interpretations of PURA §36.210(a)(5), and that CORE revealed the weakness of its argument by suggesting that the phrase "periodic rate adjustment to be applied on a system-wide basis" is somehow the same as "system-wide data must be applied on a system-wide basis." REP Coalition argued that CORE's suggested interpretation completely ignores the term "periodic rate adjustment" in PURA §36.210(a)(5), and that a plain reading of PURA §36.210(a)(5) requires the utility to apply the "rate adjustment" (i.e., the new or updated DCRF rate) on a system-wide basis (i.e., across the utility's service

area). REP Coalition contended that it is the rate —and not some other data as suggested by CORE — that must be applied system-wide. REP Coalition commented that COH’s interpretation is no more convincing than the interpretation put forward by CORE. REP Coalition contended that because any DCRF must be applied system-wide to qualify for approval under PURA §36.210, the DCRF must be a system-wide rate. Although COH claimed that there is a difference between “system-wide” rates and “rates on a system-wide basis,” arguing that “system-wide basis” should be interpreted as “system-wide rates, to the fullest extent of its jurisdiction to do so,” REP Coalition stated that COH has added to the statute the words, “to the fullest extent of its jurisdiction to do so,” but these words are not present in the statute and change the specific meaning of the provision. REP Coalition stated that where the Legislature wanted to provide the commission discretion, it knew exactly how to do so; for example, SB 1693 requires the commission to combine surcharges “to the extent possible.” REP Coalition stated that with regard to implementing “rates on a system-wide basis,” there are no such qualifying words, and thus the commission must assure that the DCRF is applied by the utility on a system-wide basis to give effect to the unambiguous language in the statute.

REP Coalition further commented that it is important to note that during the recent decade, in utility service areas where retail competition has been introduced, system-wide rates have been the norm, rather than the exception, and the reason for this outcome is partly because the commission’s policies recognize that system-wide rates foster competition better than rates set on a patchwork basis throughout a utility’s service area. REP Coalition commented that the system-wide rates are essential to REP billing systems and retail product design, and without system-wide application of an electric utility’s DCRF, the costs of billing retail electric

service will increase as both TDUs and REPs would have to extensively test billing systems to ensure that customers across various local jurisdictions are being charged the appropriate DCRF rate. REP Coalition submitted that 46 days is a sufficient period for REP Coalition to modify their contract documents and billing systems to incorporate and implement an adjustment in a TDU's DCRF, and the 46 days of "rate certainty" are critical for allowing a REP to time its retail price change with the effective date of a TDU's DCRF adjustment.

Electric Utilities commented that PURA §36.210(a)(5) states that a DCRF must "be applied by an electric utility on a system-wide basis," and consistent with that statutory language, proposed subsection (e)(6)(D) requires the presiding officer to approve DCRF rates "on a system-wide basis." Electric Utilities commented that they and REP Coalition support this provision of the rule because it is consistent with the statute and because it promotes uniformity of rates throughout a utility's service area. Electric Utilities contended that, on the other hand, CORE and COH assert the plainly mistaken argument that PURA §36.210(a)(5) does not require system-wide rates and say that subsection (e)(6)(D) must be revised to eliminate the requirement of system-wide rates. Electric Utilities commented that the simple answer to that argument is that the statute requires a DCRF to be applied on a "system-wide basis," and the only logical way to apply a DCRF on a "system-wide basis" is by setting system-wide rates. Electric Utilities disagreed with CORE's contention that the commission can comply with the statutory mandate to apply a DCRF on a system-wide basis by using "system-wide data" to determine the utility's requested rate changes, rather than by implementing a system-wide rate. Electric Utilities commented that under the actual language of PURA §36.201(a)(5), the DCRF rate itself must be applied on a system-wide

basis, and because of the statutory directive that DCRF rates be instituted on a system-wide basis, the commission will necessarily have to consider each utility's DCRF application, regardless of how the individual municipalities rule on the application. Therefore, the commission's own internal review process need not wait for action by municipalities on the DCRF requests, and to ensure that the commission is not delayed by waiting for the appeals from municipal actions, the rule should provide for automatic appeals upon expiration of the 60-day time-period for municipal review. Electric Utilities commented that city groups also argued that the rule nullifies their original jurisdiction because the requirement of system-wide rates renders municipal decisions meaningless, but that that too is wrong, as nothing in the rule prohibits municipalities from engaging in discovery and holding hearings, if they choose to do so.

Commission Response

PURA §36.210(a)(5) requires that a DCRF “be applied by an electric utility on a system-wide basis.” As indicated in subsection (d)(1) of the rule, a DCRF consists of rates that apply to the rate classes. Therefore, applying the DCRF on a system-wide basis means that a single DCRF for each rate class is applied on a system-wide basis. As explained by the REP Coalition, requiring that a DCRF be implemented on a system-wide basis is essential to promotion of a competitive retail electric market in Texas, consistent with PURA §39.001(a) and (b). This issue and the broader issue of city jurisdiction are discussed in detail above, concerning subsection (c)(1).

September 1 Effective Date

REP Coalition stated their support for the target effective date of September 1 for approved DCRF adjustments, because it will permit REPs to combine those rate changes with approved TCRF adjustments, which also take effect on September 1 under the commission rules and is therefore consistent with PURA §36.210(b)(1), which requires the simultaneous implementation of changes in an electric utility's non-fuel rates in a 12-month period, to the extent possible. By reducing the frequency of TDU rate changes and/or grouping those rate changes when possible, the number of times a year a retail customer may experience a price change due to a change in a TDU rate will decrease. Those actions will also reduce the administrative costs borne by REPs, which will lower the level of costs to be recovered from customers and consequently decrease the retail prices charged to those customers.

Commission Response

The commission has retained the September 1 effective date in the rule.

Simultaneous Implementation of Rates

REP Coalition argued the proposed rule does not comprehensively address the objective of simultaneous implementation of all TDU rates in a 12-month period. Rather, it facilitates the simultaneous implementation of only two of those rates, that is, the TCRF and the DCRF. The REP Coalition urged the commission to take every opportunity to give effect to PURA §36.210(b)(1) by combining nonfuel surcharges in a more comprehensive manner, consistent with the statute.

OPC commented that while the statute requires an electric utility in the ERCOT region to simultaneously implement non-fuel rate adjustments within a 12-month period to the extent possible, the proposed rule is concerned with just one of these rate adjustments (the DCRF). The proposed rule would require the presiding officer to set the effective date of a TDU's DCRF as September 1 unless good cause exists for a later date. OPC commented that this target effective date matches the effective date of a TCRF adjustment; thus, the proposed rule does not increase the number of non-fuel rate changes implemented on discrete dates and does not contravene the statutory requirements of simultaneous implementation. OPC commented that the current rulemaking is not the proper forum to address a comprehensive approach to the synchronization of non-fuel rates if indeed that is required by the statute as addressed in REP Coalition's comments. OPC commented that at issue presently is the implementation of an additional rate mechanism; adjustments to the implementation of other, existing rate mechanisms should be handled in separate rulemakings. To address adjustments to other rate mechanisms in this rulemaking will add complexity and potentially delay implementation of the DCRF. Additionally, parties affected by modifications to other rate mechanisms may not be participants in the current rulemaking and would be disadvantaged were the scope of the current rulemaking expanded to include modification of the other rate mechanisms by which they are affected. OPC replied that it believes that it is inappropriate to inject the issue of combining non-fuel surcharges other than the DCRF into this rulemaking.

Commission Response

The commission agrees with OPC that the scope of this rulemaking does not include consideration of simultaneous effective dates for all TDU rate changes.

Automatic Appeal

Electric Utilities and REP Coalition recommended that the appeal of a municipality's governing body's decision on a DCRF application be automatic pursuant to the rule. An automatic appeal reduces the potential for unnecessary delay in processing a DCRF application.

Oncor Cities stated that municipal jurisdiction over the rates of a utility charged within the municipal boundary is a creature of the statute that cannot be abrogated by an administrative rule. Oncor Cities submitted that Electric Utilities' notion that the commission should deem an appeal to have occurred on the 60th day after filing, regardless of the action the city took, is inconsistent with that jurisdiction. Oncor Cities stated that Electric Utilities' "deemed appeal" approach is inconsistent with this ability, inasmuch as a city that has suspended a rate change has taken no action that can be appealed. Oncor Cities stated that a city that has suspended a requested rate change retains jurisdiction until the city has made a final decision, upon which only a utility can appeal to the commission pursuant to PURA §33.051, as that section clearly speaks to a party's ability to appeal a city's "decision" to the commission, while PURA §36.108(a)(1) establishes the ability of a city to suspend the effective date *pending a decision*. Oncor Cities stated that if a city has suspended the rate change pursuant to PURA §36.108(a)(1), the "deemed appeal" that Electric Utilities urge

simply cannot occur—there is nothing that can be appealed. Even if the city has not suspended the rate change request, Electric Utilities’ proposed approach still presents problems, because if the city has simply not taken action yet, that city still retains jurisdiction. Under PURA §36.102 and §36.108, Oncor Cities have until the effective date of the application to take final action. Oncor Cities urged the commission to reject Electric Utilities’ proposal that city action be deemed appealed on the 60th day after a DCRF application is submitted.

Commission Response

As explained above concerning subsection (c)(1), PURA Chapter 36, Subchapter C (including PURA §36.108) and PURA §33.051 do not apply to a DCRF proceeding. Also as explained above concerning subsection (c)(1), a DCRF must be applied on a system-wide basis, and automatic suspension of the city’s final decision is necessary to ensure a system-wide DCRF. Likewise, deeming a DCRF application denied if the city does not make a final decision within 60 days is necessary for an expedited DCRF procedure. The commission agrees with Electric Utilities and REP Coalition that the rule should make an electric utility’s appeal automatic; doing so avoids the cost of actually appealing the city action or inaction and ensures that the appeal is made. Because an appeal is necessary to ensure a system-wide DCRF, making the appeal automatic helps ensure a system-wide DCRF. The commission has made corresponding changes to subsection (c)(1).

Delegation of Decisions to Presiding Officer

State Agencies commented that the rule improperly delegates final decisions to a “presiding officer” other than the commission. State Agencies argued that in contrast to the procedure followed for transmission cost recovery factor decisions under §25.193 and §25.239, the proposed rule improperly delegates the commission’s statutory responsibility to approve or disapprove the adjustment. State Agencies submitted that the preamble to the proposed rule does not separately describe the intended role of any “presiding officer,” which is not the commission in the adjustment process, and to the extent that this subsection of the rule intends for the presiding officer to be any entity other than the commission for purposes of approving the adjustment, this is an improper delegation of authority expressly delegated to the commission by the Legislature. State Agencies contended that the Legislature made clear that “the commission” (or other regulatory authority) would be the body to approve any rate adjustment request in the statute’s opening paragraph (a), but the proposed rule make no provision whatsoever for any commission ruling on the DCRF application and appears to empower only a “presiding officer” to make the final decision and set effective dates for utility rates. State Agencies further commented that the commission is without authority to delegate rate approval responsibility either to SOAH or to an in-house staff attorney because Texas Government Code §2003.049 states that the PUC can delegate its hearing function solely to the State Office of Administrative Hearings and, additionally, even where proper delegation is made to the SOAH utility division to hear a contested case, its proposal for decision is simply a recommendation to the sole final decision maker—the commission. State Agencies further contended that there is no statute authorizing the commission to deflect to a staff hearings officer the final decision on DCRFs. State Agencies stated §22.2(34) and §22.202 cannot be

employed to authorize delegation of ratemaking decisions that violate both the Government Code and PURA.

OPC commented that it concurred with the State Agencies' comment that the term "presiding officer" in this particular subsection should be changed to "the commission," because under the current legal setting, only the commission can exercise the functions addressed in this subsection.

Electric Utilities commented that they do not interpret subsection (e)(6)(D) as a delegation of authority by the commission to the presiding officer to decide a DCRF proceeding without commission input. Electric Utilities stated that if a DCRF application is contested, the commission will presumably decide it based on the evidence and briefing, as it does in other contested cases.

Commission Response

The DCRF rule uses the term "presiding officer" in the manner defined by §22.2(34): "The commission, any commissioner, or any hearing examiner or administrative law judge presiding over a proceeding or any portion thereof." Subsection (e)(6)(E) of the DCRF rule provides that a DCRF proceeding is eligible for disposition pursuant to §22.35(b)(1). Section 22.35(b)(1), read in conjunction with subsection (a)(2) of that section, provides that a commission administrative law judge may approve an application if it is not adverse to any party other than commission staff. Subsection (e)(6)(E) of the DCRF rule is similar to §25.192(h)(4)(C), which addresses interim TCOS applications. Commission administrative

law judges routinely approve interim TCOS applications, as well as ERCOT TCRF applications filed pursuant to §25.193, because these applications are usually not adverse to any party. Allowing commission administrative law judges to approve such applications does not prejudice any party and is an efficient use of state resources. Only one non-ERCOT TCRF application, in Docket Number 37135, has been filed under §25.239, and the Commissioners approved the application in that docket. Unlike for interim TCOS factors and ERCOT TCRFs, §25.239 requires a determination that transmission infrastructure improvement costs are reasonable and necessary before they are recovered through a non-ERCOT TCRF, as required by PURA §36.209(b).

Section 25.243(e)(6)(E): Review of Application

Oncor Cities noted that the proposed rule is silent on the ability of parties to obtain a hearing on a utility's DCRF filing, and on the ability of parties to file either testimony or a recommendation to the commission on the utility's application. Oncor Cities stated their belief that PURA §36.210(g)(2) provides that parties may conduct discovery on a utility's application for a DCRF filing, but Oncor Cities noted that discovery without the opportunity to file a recommended disposition of the utility's application for a DCRF filing and the opportunity to request a hearing renders PURA §36.210(g)(2) a nullity. Oncor Cities opined that the Legislature could not have intended that parties would be permitted to conduct discovery but then be afforded no opportunity to use that discovery.

Oncor Cities noted that APA §2001.0051(1) and (2) state that parties to a contested case are entitled to a hearing, and are entitled to present and respond to evidence and argument on each

issue involved in the case. Oncor Cities concluded that including express provisions for disposition and hearing adds clarity to the rule and ensures that DCRF proceedings are conducted in accordance with the law, and that such provisions would not obstruct the DCRF process. Oncor Cities proposed new language in proposed subsection (e)(6)(E) to address this concern.

Commission Response

Subsection (e)(6)(E) properly leaves to the presiding officer the responsibility to establish a procedural schedule based on the circumstances in a particular DCRF proceeding.

Section 25.243(e)(6)(F): Notice of Approved Rates

Electric Utilities recognized the potential difficulty associated with providing notice of approval of a rate change on “the day after” approval, given, for example, that such notice could occur on a Friday. Electric Utilities recommended that the commission change the phrase “day after” to “working day after.” In addition, Electric Utilities recommended that the commission change the provision to allow service by email.

Commission Response

The commission agrees with Electric Utilities’ recommendation that the rule should provide for notice by email, and to change the phrase “day after” to “working day after.” The notice would be provided to REPs, and REP Coalition did not object to service by email. As discussed above concerning subsection (e)(2), the DCRF rule should permit reasonable methods of notice that are more efficient than first-class mail. In addition, having the default deadline for notice of the approved rates be the working day following

the presiding officer's final decision is reasonable. The rule expressly allows the presiding officer to order a different deadline.

Section 25.243(f): DCRF Reconciliation

Carrying Charges on Refunds

Electric Utilities commented that the appropriate carrying charge for any over-recovered amounts should be the commission-approved interest rate for over-charges pursuant to §25.28(c). Electric Utilities stated that requiring the carrying charge to be equal to a utility's authorized rate of return means the utility would be paying a return on a return; and, just as in the case of any other over-charge, such as refunds for over-billing or bonded rates, the carrying charge should be consistent with the commission's rule for such refunds, which specifies a rate that is different than the utility's cost of capital.

OPC commented that Electric Utilities' argument that requiring the carrying charge on refunds of improper DCRF collections to be at the utility's cost of capital would mean utilities would be paying a return on a return ignores the fact that the return an electric utility recovers under a DCRF adjustment is a principal amount of the recovery, just like the distribution investment costs recovered under the DCRF. OPC maintained that, in addition to being the correct carrying charge, the cost of capital used as the carrying charge prevents the utility from using the DCRF process as a means of arbitrage and it would not cause economic harm to the utility.

OPC also maintained that it is clear that Electric Utilities believe the model represented by §25.192(h) (relating to interim TCOS), which uses the utility's cost of capital as the carrying

charge, is an effective rule and worthy of emulation in the development of a similar DCRF rule, as indicated in the following comment by Electric Utilities: "...the rules and procedures that the commission adopted for the recovery of transmission costs have helped support transmission investment in this state and allowed for timely and efficient changing of rates to reflect additional investment. Properly crafted, the rules for recovery of distribution investment should work in the same manner. The commission's proposal is a very good effort at achieving the same success that has been experienced with the regulation of transmission rates."

CEP, COH, TIEC, Oncor Cities, and CORE advised the commission to reject Electric Utilities' proposed change of the interest rate to be earned on pending refunds that are subject to the proposed rule from the utility's cost of capital to the over-collection refund rate for the same reasons the commission rejected a similar request in Project Number 37519 relating to §25.192(c). COH commented that the carrying cost for utility refunds must be consistent with the context and latitude associated with the proposed DCRF process and serve as a deterrent to overreaching by the utility. CORE and Oncor Cities stated that using the higher updated rate of return would better hold utilities accountable for accurately and responsibly filing applications for a DCRF proceeding. Oncor Cities additionally contended that the interest rate on over- or under-billings is more relevant to refunds covering relatively short time periods. Oncor Cities noted that the time period between DCRF updates and the utility's next base-rate case could be quite long—perhaps 4-10 years, or even more. Section 25.263(h)(4), pertaining to the interest rate recoveries associated with the final fuel reconciliation, utilizes the over- or under-billing interest rate if the time period between the fuel reconciliation and stranded cost true up is one year or less, but requires the use of the weighted cost of capital if the time interval is more than one year.

Commission Response

The commission concurs with OPC's argument that for any over-recovery refund amounts that include a return component paid by customers, that return is part of the overpayment, and refunding only those return dollars would not provide interest to, and appropriately compensate customers for, their loss of the use of the overpaid funds.

The commission agrees with CEP, COH, TIEC, Oncor Cities, CORE, and OPC that the method of determining carrying charges that is used in §25.192(h) should be used for interest earned on pending refunds in the DCRF rule for the same reasons as those cited in Project Number 37519, which amended §25.192(h), the interim TCOS rule.

As was argued by intervener groups in Project Number 37519, use of the interest rate established under §25.28 would create an arbitrage opportunity for electric utilities, because this rate is lower than the electric utilities' rates of return. In Project Number 37519, TIEC noted that if an over-recovery is refunded with an interest rate that is lower than the transmission service provider's (TSP's) authorized rate of return, the TSP will be overcompensated and theoretically have an incentive to include excessive amounts in its TCOS updates, given that the interest rate at which any over-recoveries would be refunded would be lower than the rate of return the TSP can earn on those amounts. For interest calculations on refunds from over-recoveries resulting from DCRFs, the

commission therefore rejects the use of the over- and under-billing rate specified in §25.28 and retains the language of the published rule.

Improperly Recovered Revenues

TIEC suggested modifications that TIEC contended will bring the rule's language into conformance with statutory language intended to provide a refund to customers for "any amount improperly recovered" through the DCRF. TIEC observed that this includes amounts that were added to rates in relation to a proper investment but were over-recovered due to load growth or other factors. CORE supported TIEC's proposed revision. In addition, CORE stated that subsection (f) of the DCRF rule should not permit a reconciliation to consider whether a utility's investments were prudent, reasonable, or necessary unless the reconciliation occurs in a base-rate proceeding. Otherwise, contrary to the intended scope of the rule, the prudence of an investment would be considered using a truncated schedule inadequate for such review. State Agencies contended that the commission should retain the right to review, during the next base-rate case, whether costs recovered through a DCRF were improperly recovered, not just whether the investments are prudent, reasonable, and necessary.

OPC concurred with TIEC in its observation and comments that PURA §36.210(f)(6)(B) requires the commission in a DCRF reconciliation to consider whether "any amount" was "improperly recovered" through the DCRF and to refund the improper amounts with appropriate carrying charges. TIEC commented that PURA §36.210(f)(6)(A) does not limit the scope of a DCRF reconciliation to a consideration of only whether the costs included in a DCRF were prudent, reasonable, and necessary; rather, §36.210(f)(6)(A) states that the

commission is not prevented from “reviewing” the investment costs in a DCRF and considering these issues. TIEC argued that in a DCRF reconciliation, which is anticipated to be a part of the utility’s next base-rate case, the commission is required to consider all amounts recovered through a DCRF since the utility’s previous base-rate case.

Electric Utilities submitted that the proposed rule properly defines the scope of reconciliation and that TIEC’s argument that the scope should include additional amounts recovered due to load growth as well as State Agencies’ argument that legislative language requires the scope to include any amount improperly recovered should be rejected.

Electric Utilities noted that the language in the statute requiring the refund of “any amount improperly recovered through the periodic rate adjustments,” when considered in context, clearly is a reference to whether the costs were prudent, reasonable, and necessary. Electric Utilities cited subsection (f) of SB 1693 and maintained that the proximity of the language providing for a refund to the language concerning a review of whether they were “prudent, reasonable, and necessary” clearly suggests that the basis of the refund relates to whether the investments were prudent, reasonable or necessary.

Electric Utilities also contended that additional revenues that may result from load growth after a DCRF is set and in place are simply revenues collected under an approved rate and, absent a finding that some portion of the investment was imprudent, unreasonable, or unnecessary, should not be refunded.

Commission Response

PURA §36.210(f)(6)(B) requires that “any amount improperly recovered” through the DCRF be refunded. The word “improperly” is vague. As a result, the Legislature gave the commission discretion in applying PURA §36.210(f)(6)(B). A non-ERCOT TCRF is trued-up to avoid over-recovery of costs due to load growth. *See* §25.239(f). This true-up is required by PURA §36.209(b), which provides that the commission may not allow an electric utility to over-recover costs through a non-ERCOT TCRF. An ERCOT TCRF is also trued-up to avoid over-recovery of costs due to load growth. *See* §25.193(b)(2)(B)(iii). This true-up is appropriate, because costs that are recovered through an ERCOT TCRF are a pass-through of transmission service charges from other utilities. *See Rulemaking Proceeding to Amend P.U.C. SUBST. R. 25.193, Relating to Distribution Service Provider Transmission Cost Recovery Factor (TCRF), Project Number 37909, Order Adopting Amendment to §25.193 as Approved at the September 29, 2010 Open Meeting at 7.*

Transmission costs recovered through an interim TCOS factor (ITF) are not trued-up for load growth. *See* §25.192(h). Costs recovered through an ITF are related to the transmission invested capital of the utility using the ITF. As with base-rate costs, which are predominantly related to a utility’s own invested capital, the lack of a true-up for load growth, or load declines, is part of the utility’s overall operating risk profile. A DCRF will recover costs related to a utility’s own invested capital, and it is appropriate not to true-up the DCRF for changes in load.

The proper scope of a reconciliation is to review the invested capital that was included in the DCRF. PURA §36.210(f)(6)(A) contemplates that the commission will determine whether the invested capital costs were prudent, reasonable, and necessary. In addition, PURA §36.210(f)(a) uses PURA §36.053 to define invested capital. Among other things, that section requires that a cost be used by and useful to the utility in providing service in order to be considered invested capital for ratemaking purposes. PURA §36.058 requires that certain standards be met for payments by a utility to an affiliate in order for those payments to be included as invested capital for ratemaking standards. In adopted subsection (f), the commission has expressly included all of these PURA requirements within the scope of a DCRF reconciliation.

Reconciliation Based on Scope of Proceeding

Electric Utilities recommended a revision to subsection (f) removing the language in the first sentence that accommodates the idea of a review of the reasonableness of the investment taking place in a DCRF proceeding.

Commission Response

For the reasons discussed above concerning subsection (e)(5), the commission declines to make this change.

Section 25.243(g): DCRF's effect on Electric Utility's Financial Risk and Rate of Return

Electric Utilities advised that this provision should be stricken because it was not part of SB 1693, nor required under PURA §36.052, and the commission has many other factors to consider

in determining ROE. Electric Utilities stated that this provision inappropriately elevates the importance of a DCRF.

OPC disagreed with Electric Utilities' contention that the financial risk provision not being included in the language of PURA §36.210 indicates that the Legislature intended for it not to be explicitly evaluated. OPC asserted that a reasonable person might conclude that adjustments to reflect reduction in risk, because they are not specifically excluded in the statute, could be considered within the DCRF evaluation.

COH commented that implementation of the DCRF will allow utilities greater assurance of timely and full collection of their distribution service costs, and as a result, may reasonably be expected to lower the risk associated with such service. The commission, therefore, should expressly consider the effect of the DCRF on the utility's financial risk and rate of return.

TIEC commented that it is well-accepted that allowing utilities to implement rate increases between base-rate proceedings reduces their regulatory lag and financial risk, and this should be explicitly acknowledged in the rule. TIEC noted that the revised TCOS rule adopted in Project No. 37519 included similar language acknowledging that utilities' rates of return should be reduced to reflect their reduced risk resulting from automatic recovery mechanisms in the next base-rate proceeding, and that this language was also included in the staff's Proposal for Adoption in Project Number 39298, *Rulemaking Related to Recovery by Electric Utilities of Distribution Costs*. TIEC therefore supported the inclusion of this provision.

Oncor Cities maintained that Electric Utilities do not and cannot dispute that the DCRF reduces the risk of regulatory lag for electric utilities in Texas. Oncor Cities, State Agencies, and CORE recommended that the commission apply a presumptive 25 basis point adjustment for reduced risk to the rates of return applied to new capital investment recovered through the DCRF and added that this could be reduced or eliminated upon a showing of good cause and would not change the rate of return applied to embedded investment in the utility's last rate order. State Agencies held that Electric Utilities want to have this issue both ways: they seek to reduce investor risk through piecemeal, direct-rate recovery without a full-blown rate case, then argue that the approved return should not be reduced to reflect lowered rate risk of regulatory lag. CORE urged the commission to strengthen this subsection of the rule by expressly requiring the commission to consider the effect of the DCRF on the utility's financial risk and rate of return.

OPC agreed with Oncor Cities and CORE that a DCRF reduces a utility's financial and investment risk and, therefore, its use warrants a review of the rate of return used in the DCRF calculation. OPC added that adoption of a standard adjustment may expedite processing of DCRF proceedings; however, OPC held that the method for determining the rate of return as described in §25.243(d)(2) is a reasonable compromise position when evaluated in conjunction with the earnings monitoring report.

Walmart advised that staff's efforts to recognize that the DCRF reduces regulatory lag in the recovery of distribution costs would appropriately reduce the associated risk of recovery of those costs. As such, Walmart proposed no change to proposed subsection (g).

Electric Utilities stated that Oncor Cities acknowledge that nothing in PURA §36.210 requires explicit recognition of the effects of the DCRF on financial risk and that it is unfair to single out one factor that may ameliorate risk, such as the DCRF, without also accounting for factors that increase risk for Texas utilities, such as consolidated tax savings adjustments. Electric Utilities also disagreed that the commission should have made consideration of the DCRF mandatory, rather than permissive, when setting a utility's rate of return. Electric Utilities further disagreed with Oncor Cities that the commission should specify a 25-basis point reduction to account for the DCRF, and stated that Oncor Cities have presented no evidence to suggest that 25 basis points is the correct measure of diminished risk.

Commission Response

PURA §36.052 requires that the commission consider “applicable factors” in setting an electric utility’s rate of return. A DCRF may be an applicable factor to expressly consider when setting an electric utility’s rate of return. Therefore, subsection (g) is appropriate. However, requiring a specific basis-point reduction because of the DCRF would be inappropriate, because the effects of a DCRF on electric utilities’ financial risk will vary from utility to utility. Thus, the effects of a DCRF are best considered on a case-by-case basis.

With respect to the general impact of a DCRF on an electric utility’s financial condition, the commission observes that the opportunity for a DCRF application as often as once every calendar year clearly provides for reduced regulatory lag, which

eliminates at least some degree of uncertainty with respect to the timing of an electric utility's recovery of investment. A reduction in regulatory lag during a period when an electric utility is increasing its investments positively impacts the electric utility's financial condition.

Section 25.243(i): Expiration

COH commented that while the proposed rule would expire on January 1, 2017 when its enabling legislation expires, the proposed rule contemplates that “any DCRF in effect at that time shall remain in effect until the utility's next comprehensive base rate proceeding.” COH commented that, for example, a rate adjustment put into effect in 2016 could conceivably stay in place for many years beyond the expiration of the enabling statute and rule, clearly exceeding the legislative grant of authority. COH commented that it believes that the proposed indefinite time frame would be inappropriate, because it represents an attempt to circumvent the statutory sunset date. COH suggested that DCRF interim adjustments remain in effect only until January 1, 2017. CORE agreed with COH.

Electric Utilities disagreed, stating that the commission would have authority to provide for a DCRF adjustment even absent SB 1693. Electric Utilities expressed the belief that SB 1693 clarifies that the commission has the authority to adopt DCRFs for certain non-fuel items related to distribution costs and that nothing in the statute would prohibit or require municipalities or the commission to approve an electric utility tariff that periodically adjusts a non-fuel rate outside a general rate case or prohibits them from doing so.

Commission Response

PURA §36.210 does not require that a DCRF expire on the expiration of that section. After PURA §36.210 expires, a DCRF should remain in effect until the electric utility's next comprehensive base-rate proceeding, similar to the way that the DCRF will operate when PURA §36.210 is in effect. In that way, the utility's base rates can be adjusted at the same time that the DCRF is terminated or set to zero. In addition, PURA §36.210(h) expressly contemplates that the Legislature may extend or remove the expiration date for PURA §36.210.

General Issue: Inaccurate Preamble

State Agencies commented that the preamble to the published rule was inaccurate because it failed to comply with the disclosures required by Texas Government Code §2001.024(a)(4). State Agencies stated that the Legislature requires state agencies to make detailed disclosures about the impact of proposed rules, and an integral part of that disclosure is the "fiscal note," which must alert state and local governments of any fiscal consequences. State Agencies commented that the preamble to proposed §25.243 merely recited that "there will be no fiscal implications for state or local government as a result of enforcing or administering the section," and State Agencies submitted that adequate notice is essential for fairness as well as meaningful opportunity to comment on a proposed rule. State Agencies commented that while the commission was not required to come up with dollar amounts of impact, it is simply untrue that there would be "no" fiscal consequences that result from administration or enforcement of the rule by any party, as the local governments that act as regulatory authorities would be required to add yet another proceeding to consider rates, and have paper work expense to duplicate and distribute the DCRF forms to its

governing boards and attorneys. State Agencies submitted that adapting to the more frequent periodic increases in the rates charged by regulated utilities for service to state agencies and institutions would be certain to have a fiscal impact.

Electric Utilities disagreed with State Agencies because under the proposed rule, local regulatory authorities need do absolutely nothing in response to a DCRF filing, because if they do nothing, the application would be deemed denied 60 days after filing. Electric Utilities asserted that the proposed rule would in no way require any municipality to expend any resources.

Commission Response

The preamble to the proposed rule properly states that there will be no fiscal implications for state or local government as a result of enforcing or administering the DCRF rule. The commission will use existing resources to administer and enforce the DCRF rule. The commission expects that cities exercising original jurisdiction will do so as well. Furthermore, a city may choose to take no action on a DCRF application, and under subsection (c)(1), the DCRF application will be automatically appealed to the commission and consolidated with the DCRF proceeding before the commission.

The predominant costs and benefits of the rule are the result of implementing PURA §36.210. State and local governments' electricity costs will be affected by the rule in a manner similar to other electricity customers. PURA §36.210(h) delineates a study and report on DCRFs that the commission is required to undertake for the Legislature.

Performing the costs analysis suggested by State Agencies would be an inefficient use of state resources.

Proposed New Subsection: Burden of Proof

CORE believed that the rule should expressly state that in a DCRF proceeding the electric utility bears the burden of proving that its requested relief complies with PURA §36.210 and §25.243, including that the electric utility is not earning more than its authorized rate of return, on a weather-normalized basis, at the time the application is filed.

Commission Response

Addressing the burden of proof in a DCRF proceeding is unnecessary, because it is well established that, pursuant to PURA §36.006, an electric utility has the burden of proof in a rate change proceeding, such as a DCRF proceeding. The interim TCOS, ERCOT TCRF, and non-ERCOT TCRF rules do not expressly address burden of proof.

Proposed New Subsection: Municipal rate case expenses

CORE proposed new subsection (e)(6)(H), Municipal Rate Case Expenses. CORE commented that under PURA §33.023, municipalities were entitled to receive reimbursement for the reasonable costs of participating in or conducting a ratemaking proceeding, and that in passing SB 1693, the Legislature not only acknowledged the applicability of PURA §33.023 to DCRFs, but also expressly stated its intent not to limit the ability of a municipality to obtain reimbursement under PURA §33.023. CORE stated that the proposed DCRF rule did not include a provision that acknowledges a municipality's right to reimbursement for reasonable expenses relating to

participating in a DCRF filing, nor did the proposed rule include a provision that prescribes the method for the municipality to request reimbursement and the electric utility to actually reimburse the municipality its reasonable costs associated with participating in the DCRF filing. CORE submitted that the new rule must address how municipalities would be reimbursed for their reasonable expenses associated with participating in a DCRF filing to ensure that the municipality would be reimbursed for such expenses in the DCRF filing, consistent with PURA §33.023 and PURA §36.210. CORE requested that the commission add subsection (e)(6)(H) specifying that a municipality's reasonable rate-case expenses be reimbursed to the municipality within 30 days after the municipality submits its request for reimbursement. CORE commented that the rule should also specify that a municipality should file its rate case expenses within one week of the conclusion of a hearing on the merits or within one week after the deadline by which a hearing must be requested has passed. CORE stated that the rule may specify that an electric utility may seek to recover any reimbursed municipality rate case expenses in the utility's next DCRF reconciliation proceeding.

Oncor Cities also commented that PURA §36.210(f)(5) requires that the mechanism adopted pursuant to this section not limit the ability of cities to be reimbursed for their reasonable rate case expenses pursuant to PURA §33.023, but despite this specific reference to reimbursement of municipal rate case expenses in the statute, the proposed rule was silent on the subject. Oncor Cities submitted that greater clarity and certainty would be lent to the DCRF process if the reimbursement of rate-case expenses was addressed in the rule, and this would especially be so given the short timeline for a DCRF filing proceeding, and the corresponding limited ability of parties to litigate additional issues.

Oncor Cities commented that its proposed rule language makes clear that a DCRF proceeding is one in which reasonable municipal rate-case expenses are reimbursable, and also requires that reimbursement occur on a timely basis. Oncor Cities commented that in recent ratemaking proceedings, at least one utility has proposed unreasonable reimbursement schedules, including, for instance, a proposal to reimburse cities on a monthly basis for the life of a proposed 12-year advanced metering system (AMS) surcharge, and Oncor Cities' suggested language would bar such proposals and would therefore reduce costly litigation.

Oncor Cities' proposed language would state that reimbursement of cities' reasonable expenses for a given DCRF proceeding should occur within that proceeding, as any other arrangement would place an unreasonable burden on municipal intervenors. Oncor Cities argued that requiring cities to wait to quantify and receive their rate-case expense reimbursement until a subsequent DCRF update proceeding would put municipal rate-case expense recovery at the whim of the utility, and there is no requirement in the statute or proposed rule that a utility file for a DCRF update every year. Oncor Cities commented that it should not be put in a position of potentially waiting years to have reimbursable rate-case expenses addressed by the commission and paid by the utility.

COH commented that the proposed rule ignored the reality that local rate regulation, interim or comprehensive, would incur costs subject to reimbursement under PURA §33.023 as contemplated by PURA §36.210(f)(5). COH suggested adding language under subsection (e)(3) to address the issue.

Electric Utilities agreed that the DCRF proceeding would be a ratemaking proceeding that would permit municipalities to recover reasonable expenses, but stated that revising the proposed rule to address municipal rate-case expense recovery would be unnecessary and delay adoption of the rule. Electric Utilities commented that PURA §33.023 already provides for municipal expense recovery in ratemaking proceedings, and determinations of the mechanics and timing of any reimbursement to municipalities would be best addressed in light of the evidence in the record of a case as opposed to a detailed reimbursement process in a rule.

Commission Response

The commission concludes that including in the rule a specific provision for recovery of rate-case expenses is not necessary. The commission has addressed reimbursement of city rate-case expenses for many years without addressing that issue in a rule.

All comments, including any not specifically referenced herein, were fully considered by the commission. In adopting this section, the commission has made changes consistent with the discussion above and to clarify its intent.

The new rule section is adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 2007 and Supp. 2010) (PURA), which provides the commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, SB 1693 §1 (to be codified as PURA §36.210), which requires the commission to adopt rules to implement the section; PURA §36.052, which requires the commission to consider applicable factors in establishing a reasonable return on invested capital;

PURA §36.053, which addresses invested capital; and PURA §36.058, which addresses an electric utility's payment to an affiliate.

Cross Reference to Statutes: PURA §§14.002, 36.052, 36.053, and 36.058; and SB 1693 §1 (to be codified as PURA §36.210).

§25.243. Distribution Cost Recovery Factor (DCRF).

- (a) **Purpose and application.** This section implements Public Utility Regulatory Act (PURA) §36.210. This section applies to electric utilities, including transmission and distribution utilities (TDUs), that provide wholesale or retail distribution service.
- (b) **Definitions.** The following terms, when used in this section, have the following meanings unless the context indicates otherwise.
- (1) **Capitalized operations and maintenance expenses** -- Expenses that have been deferred or amortized as a regulatory asset or liability.
 - (2) **DCRF proceeding** -- A proceeding conducted pursuant to this section in which creation or amendment of a DCRF is considered on application of an electric utility to the commission pursuant to subsection (c)(1) of this section.
 - (3) **Distribution invested capital** -- The parts of the electric utility's invested capital, as described in PURA §36.053, that are categorized as distribution plant, distribution-related intangible plant, and distribution-related communication equipment and networks properly recorded in Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 303, 352, 353, 360 through 374, 391, and 397. Distribution invested capital includes only costs: for plant that has been placed into service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. Distribution invested capital does not include: generation-related costs; transmission-related costs, including costs recovered through rates set pursuant to §25.192 of this title (relating to Transmission Service Rates), §25.193 of this title (relating to

Distribution Service Provider Transmission Cost Recovery Factors (TCRF)), or §25.239 of this title (relating to Transmission Cost Recovery Factor for Certain Electric Utilities); indirect corporate costs; capitalized operations and maintenance expenses; and distribution invested capital recovered through a separate rate, including a surcharge, tracker, rider, or other mechanism. In a DCRF proceeding, an electric utility may elect not to seek recovery of certain distribution invested capital, but may not exclude all of the distribution invested capital in one of the accounts identified above unless the electric utility can prove that the distribution invested capital in the account reduced by the related accumulated depreciation is greater than the distribution invested capital in the account reduced by the related accumulated depreciation used in setting rates in the electric utility's last comprehensive base-rate proceeding.

- (4) **Net distribution invested capital** -- Distribution invested capital less accumulated depreciation and adjusted for any changes in distribution-related accumulated deferred federal income taxes and excluding any impact associated with Financial Accounting Standards Board Interpretation No. 48 (FIN 48).
 - (5) **Weather-normalized** -- Adjusted for normal weather using weather data for the most recent ten calendar years.
- (c) **Application for a DCRF.**
- (1) **General requirements.**
 - (A) **Filing of application.** An electric utility may apply for inclusion of a DCRF in its tariffs for wholesale and retail distribution service. To

implement a DCRF, an electric utility shall file the application for the DCRF simultaneously with all regulatory authorities having original jurisdiction over the electric utility's distribution service area.

- (B) **Municipal proceedings.** A municipality's governing body with original jurisdiction over an application for a DCRF shall make a final decision on the application within 60 days after the application was filed. If the governing body does not make a final decision within 60 days after the application was filed, the application is deemed denied by the governing body. On the 60th day after the application is filed, the electric utility is deemed to appeal the governing body's final decision to the commission, regardless of whether the governing body approves or denies the application, and the appeal is deemed at that time to be consolidated with the electric utility's DCRF proceeding before the commission. In addition, the governing body's interim and final decisions are deemed automatically suspended at the times they took effect.
- (C) **Frequency of DCRF proceedings.** An electric utility may have no more than one DCRF (including a DCRF amendment) become effective each calendar year pursuant to an application filed pursuant to this paragraph. An electric utility may change its rates pursuant to a DCRF no more than four times between comprehensive base-rate proceedings. An electric utility shall not apply for a DCRF while a comprehensive base-rate proceeding for the electric utility is pending. In addition, the presiding officer shall dismiss an electric utility's application for a DCRF if the

electric utility or commission initiates a comprehensive base-rate proceeding within 145 days after the electric utility filed the application for a DCRF.

- (2) **Requirements applicable to TDUs.** A TDU may file an application for a DCRF only during the period April 1 through April 8. A TDU shall not file an application for a DCRF after April 8 of a year even if April 8 is not a working day, as defined by §22.2(44) of this title (relating to Definitions).
- (3) **Requirements applicable to other electric utilities.** An electric utility that does not offer customer choice may file an application for a DCRF at any time other than in April and May.

(d) **Calculation of DCRF.**

- (1) **DCRF formula.** The DCRF for each rate class shall be calculated using the following formula:

$$\frac{[(DIC_C - DIC_{RC}) * ROR_{AT}] + (DEPR_C - DEPR_{RC}) + (FIT_C - FIT_{RC}) + (OT_C - OT_{RC}) - \sum(DISTREV_{RC-CLASS} * \%GROWTH_{CLASS})}{ALLOCC_{CLASS} / BDC_{CLASS}}$$

Where:

DIC_C = Current Net Distribution Invested Capital.

DIC_{RC} = Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

ROR_{AT} = After-Tax Rate of Return as defined in paragraph (2) of this subsection.

$DEPR_C$ = Current Depreciation Expense, as related to Current Gross Distribution Invested Capital, calculated using the currently approved depreciation rates.

$DEPR_{RC}$ = Depreciation Expense, as related to Gross Distribution Invested Capital, from the last comprehensive base-rate proceeding.

FIT_C = Current Federal Income Tax, as related to Current Net Distribution Invested Capital, including the change in federal income taxes related to the change in return on rate base and synchronization of interest associated with the change in rate base resulting from additions to and retirements of distribution plant as used to compute Net Distribution Invested Capital.

FIT_{RC} = Federal Income Tax, as related to Net Distribution Invested Capital from the last comprehensive base-rate proceeding.

OT_C = Current Other Taxes (taxes other than income taxes and taxes associated with the return on rate base), as related to Current Net Distribution Invested Capital, calculated using current tax rates and the methodology from the last comprehensive base-rate proceeding, and not including municipal franchise fees.

OT_{RC} = Other Taxes, as related to Net Distribution Invested Capital from the last comprehensive base-rate proceeding, and not including municipal franchise fees.

$DISTREV_{RC-CLASS}$ (Distribution Revenues by rate class based on Net Distribution Invested Capital from the last comprehensive base-rate proceeding) = $(DIC_{RC-CLASS} * ROR_{AT}) + DEPR_{RC-CLASS} + FIT_{RC-CLASS} + OT_{RC-CLASS}$.

$\%GROWTH_{CLASS}$ (Growth in Billing Determinants by Class) = $(BD_{C-CLASS} - BD_{RC-CLASS}) / BD_{RC-CLASS}$

$DIC_{RC-CLASS}$ = Net Distribution Invested Capital allocated to the rate class from the last comprehensive base-rate proceeding.

$DEPR_{RC-CLASS}$ = Depreciation Expense, as related to Gross Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding.

$FIT_{RC-CLASS}$ = Federal Income Tax, as related to Net Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding.

$OT_{RC-CLASS}$ = Other Taxes, as related to Net Distribution Invested Capital, allocated to the rate class in the last comprehensive base-rate proceeding, and not including municipal franchise fees.

$ALLOC_{CLASS}$ = Rate Class Allocation Factor approved in the last comprehensive base-rate proceeding, calculated as: total net distribution plant allocated to rate class, divided by total net distribution plant. For situations in which data from the last comprehensive base-rate proceeding are not available to perform the described calculation, the Rate Class Allocation Factor shall be calculated as the total distribution revenue requirement allocated to the rate class (less any identifiable amounts explicitly unrelated to Distribution Invested Capital) divided by the total distribution revenue requirement (less any identifiable amounts explicitly unrelated to Distribution Invested Capital) for all classes as approved by the commission in the electric utility's last comprehensive base-rate case.

$BD_{C-CLASS}$ = Rate Class Billing Determinants (weather-normalized and adjusted to reflect the number of customers at the end of the period) for the 12 months ending on the date used for purposes of determining the Current Net Distribution Invested Capital. For customer classes billed primarily on the basis of kilowatt-hour billing determinants, the DCRF shall be calculated using kilowatt-hour billing determinants. For customer classes billed primarily on the basis of demand billing determinants, the DCRF shall be calculated using demand billing determinants.

$BD_{RC-CLASS}$ = Rate Class Billing Determinants used to set rates in the last comprehensive base-rate proceeding.

If an input to the DCRF formula from the last comprehensive base-rate proceeding is not separately identified in that proceeding, it shall be derived from information from that proceeding.

- (2) **Return on invested capital.** The electric utility's rate of return is the rate of return approved by the commission in the electric utility's last comprehensive

base-rate proceeding if the final order (which may be an order on rehearing) approving the rate of return was filed less than three years before the application for a DCRF was filed. If the final order approving the rate of return was filed three years or more before the application for a DCRF was filed, the rate of return is the lesser of the rate of return in the final order or the alternative rate of return calculated as follows: The alternative rate of return shall be calculated using a 10% cost of equity, the capital structure approved by the commission in the electric utility's last comprehensive base-rate proceeding, and the cost of debt as reported in the electric utility's most recent Earnings Monitoring Report filed pursuant to §25.73 of this title (relating to Financial and Operating Reports).

- (3) **Determination of Distribution Invested Capital.** The electric utility must clearly identify any costs included as distribution invested capital because of a change in accounting rules or practices since the test year in the electric utility's most recent comprehensive base-rate proceeding. The commission shall exclude such costs if the electric utility does not prove that the costs are appropriate for recovery through the DCRF.

(e) **Procedures for DCRF proceeding.**

- (1) **Filing requirements.** To file an application for a DCRF, an electric utility shall use the commission-prescribed form and include a sworn statement from an appropriate employee of the electric utility that the application complies with the electric utility's tariff and this section, including that the distribution invested capital in the application includes only costs: for plant that has been placed into

service; that comply with PURA, including §36.053 and §36.058; and that are prudent, reasonable, and necessary. In addition, the sworn statement shall state that the application is true and correct to the best of the employee's knowledge, information, and belief. Furthermore, the electric utility shall include in its application an earnings monitoring report for the immediately preceding calendar year prepared in accordance with §25.73(b) of this title.

- (2) **Notice and intervention deadline.** By the day after it files its application, the electric utility shall provide notice of its application, using a reasonable method of notice, to all parties in the electric utility's last comprehensive base-rate proceeding and, if applicable, last DCRF proceeding, and shall include in the notice the docket number for the new proceeding. The intervention deadline is 30 days from the date service of notice is completed.
- (3) **Parties.** The Office of Public Utility Counsel and affected parties may participate as parties in a DCRF proceeding.
- (4) **Denial due to earnings.** The commission shall deny an electric utility's application for a DCRF if the earnings monitoring report included in the electric utility's application shows that the electric utility is earning more than its authorized rate of return using weather-normalized data. In making this determination, the commission shall correct the calculation of the earned rate of return in the earnings monitoring report to the extent that the calculation does not comply with §25.73(b) of this title and any form adopted to implement that subsection.

- (5) **Scope of proceeding.** The issues of whether distribution invested capital included in an application for a DCRF or DCRF adjustment complies with PURA, including §36.053 and §36.058, and is prudent, reasonable, and necessary shall not be addressed in a DCRF proceeding unless the presiding officer finds that good cause exists to address these issues.
- (6) **Commission processing of application.**
- (A) **Sufficiency of application.** A motion to find an application materially deficient shall be filed no later than 30 days after service of notice is completed. The motion shall be served on the electric utility by hand delivery, facsimile transmission, or overnight courier delivery, or by e-mail if agreed to by the electric utility or ordered by the presiding officer. The motion shall specify the nature of the deficiency and the relevant portions of the application, and cite the particular requirement with which the application is alleged not to comply. The electric utility's response to a motion to find an application materially deficient shall be filed no later than five working days after such motion is received. If within ten working days after the deadline for filing a motion to find an application materially deficient, the presiding officer has not issued a written order concluding that material deficiencies exist in the application, the application is deemed sufficient.
- (B) **Discovery.** Each party, other than commission staff, may serve no more than 20 requests for information and requests for admissions of fact pursuant to §22.144 of this title (relating to Requests for Information and

Requests for Admission of Facts), except where the presiding officer finds good cause for a party to serve additional requests. Except for a request by commission staff, a request shall not include subparts or multiple questions, and requests shall be sequentially numbered, regardless of whether the requests are served at the same time or on different parties. A response to a request shall be served no later than ten working days after receipt of the discovery request. An objection to a request shall be filed no later than five working days from receipt of the request. A request for which an objection is filed does not count towards a party's request limit. A party may request a technical conference by the intervention deadline, and shall identify the topics that it wants to discuss. An electric utility shall hold the technical conference in Austin, Texas five working days after the intervention deadline, unless the electric utility and the parties who requested the technical conference agree to a different date. The technical conference shall be held at the location designated by the electric utility, unless the commission staff designates a location. The electric utility shall have appropriate persons attend the technical conference to answer questions. A party may take a deposition only if authorized by the presiding officer.

- (C) System-wide rates and effective date of DCRF. The presiding officer shall approve the DCRF for an electric utility on a system-wide basis and set the effective date of the DCRF for a TDU as September 1 unless good cause exists for a later date. The presiding officer shall make a final

decision on a DCRF application made by a TDU at least 46 days before the effective date of the approved rates, even if this requirement results in an effective date after September 1. For an electric utility that does not offer customer choice, the presiding officer shall set the effective date of the DCRF to be 145 days after the application was filed unless good cause exists for a later date.

(D) Review of application. A DCRF proceeding is eligible for disposition pursuant to §22.35(b)(1) of this title (relating to Informal Disposition).

(E) Notice of approved rates. Unless otherwise ordered, a TDU shall serve notice of the approved rates and the effective date of the approved rates by the working day after the presiding officer's final decision, to retail electric providers that are authorized by the registration agent to provide service in the TDU's distribution service area. Notice under this subparagraph of this paragraph may be served by email.

(f) **DCRF reconciliation.** The commission shall reconcile investments recovered through a DCRF in the electric utility's next comprehensive base-rate proceeding to the extent such reconciliation did not already occur in a DCRF proceeding pursuant to subsection (e)(5) of this section. The reconciliation shall be limited to the issues of the extent to which the investments complied with PURA, including §36.053 and §36.058, and this section and were prudent, reasonable, and necessary. To the extent that the commission determines that the investments did not comply with PURA and this section or were not prudent, reasonable, and necessary, the electric utility shall refund all revenues related to the

investments that it improperly recovered through rates, and shall also pay its customers carrying charges on these revenues. The carrying charges shall be determined as follows: For the time period beginning with the date on which over-recovery is determined to have begun to the effective date of the new base rates, carrying costs shall be calculated using the same rate of return that was applied to the investments in the DCRF proceedings that resulted in the over-recovery. For the time period beginning with the effective date of the new base rates, carrying costs shall be calculated using the electric utility's rate of return authorized in the comprehensive base-rate proceeding.

- (g) **DCRF's effect on electric utility's financial risk and rate of return.** In setting the rate of return for an electric utility with a DCRF, the commission may expressly consider the effect of the DCRF on the electric utility's financial risk and rate of return.
- (h) **Reports.** An electric utility with a DCRF shall file reports that will permit the commission to monitor its DCRF revenues, in accordance with any filing requirements and schedules prescribed by the commission pursuant to §25.73 of this title or this section.
- (i) **Expiration.** This section expires upon the expiration of PURA §36.210. Any DCRF in effect at that time shall remain in effect until the electric utility's next comprehensive base-rate proceeding.

This agency hereby certifies that the rule, as adopted, has been reviewed by legal counsel and found to be within the agency's authority to adopt. It is therefore ordered by the Public Utility Commission of Texas that §25.243, relating to Distribution Cost Recovery Factor (DCRF), is hereby adopted with changes to the text as proposed.

SIGNED AT AUSTIN, TEXAS on the 22nd day of SEPTEMBER 2011.

PUBLIC UTILITY COMMISSION OF TEXAS

DONNA L. NELSON, COMMISSIONER

KENNETH W. ANDERSON, JR., COMMISSIONER