The Public Utility Commission of Texas (commission) adopts new §25.90 relating to Market Power Mitigation Plans, new §25.91 relating to Generating Capacity Reports, and new §25.401 relating to Share of Installed Generation Capacity with changes to the proposed text that was published in the April 28, 2000 *Texas Register* (25 TexReg 3665). Project Number 21081 was assigned to this proceeding. The new rules are necessary to implement provisions of the Public Utility Regulatory Act (PURA) §§39.154, 39.155, 39.156, and 39.157. Section 25.90 establishes requirements and procedures for utilities and power generation companies that own and control more than 20% of the installed generation capacity located in, or capable of delivering electricity to, a power region to file market power mitigation plans. Section 25.91 establishes reporting requirements and procedures for each person, power generation company, municipally owned utility, electric cooperative, and river authority that owns generation facilities and offers electricity for sale in the state to file annual generating capacity reports. Section 25.401 establishes initial filing requirements and components of the calculation method to be used in determining whether a power generation company owns and controls more than 20% of the installed generation capacity located in, or capable of delivering electricity to, a power region.

A public hearing on the proposed sections was held at the commission's offices at 9:30 a.m. on June 1, 2000. Representatives from Central and South West (CSW), Entergy Gulf States (EGSI or Entergy), FPL Energy (FPLE), Certain Power Generation Companies (PGCs), and Reliant Energy (Reliant), made comments at the hearing. To the extent that any party's comments at the hearing differed from their written comments, such comments are summarized herein.

The commission received written comments on proposed §25.90 from CSW, Reliant, EGSI, El Paso Electric (EPE), and TXU Electric Company (TXU). The commission also received reply comments on §25.90 from PG&E Corporation (PG&E) and Texas Industrial Energy Consumers (TIEC).

The commission received written comments on proposed §25.91 from Alcoa, Inc. (Alcoa), Austin Energy (AE), City Public Service of San Antonio (CPS), CSW, EGSI, EPE, FPLE, PGCs, PG&E, Occidental Chemical Corporation (OxyChem), Reliant, Southwestern Public Service (SPS), TIEC, and TXU. The commission also received reply comments on §25.91 from CSW, PGCs, PG&E, Reliant, and TIEC.

The commission received written comments on proposed §25.401 from PG&E, Reliant, SPS, EGSI, CSW, TIEC, TXU, and Office of Public Utility Counsel (OPC). The commission also received reply comments on §25.401 from CSW, EGSI, PG&E, Reliant, TIEC, and TXU.

The commission requested comments on the following preamble question concerning proposed §25.401:

PURA §39.154(d) defines the term "installed generation capacity" in terms of generation capacity that is "potentially marketable." Subsection (e)(2) identifies several categories of generation that are not considered to be potentially marketable. The commission invites comments on whether these categories should be excluded from the denominator.

CSW, Entergy, Reliant, SPS, and TXU commented that all of the categories listed in §25.401(e)(2)(A)-(G) are potentially marketable and should not be excluded from the denominator in calculating market share. They argued that the proposed exclusions in (e)(2) are not consistent with PURA or the Legislature's intent. Reliant averred that generation will be sold into the market if the price is right, even if the generation was built or will be built to primarily serve on-site generation. It added that the fact that a generator did not previously sell at wholesale is not an indication that the unit will not participate in the wholesale market in the future. TXU commented that the exclusionary nature of subsection (e)(2) is at odds with the broad, all-inclusive statutory definition of "installed generation capacity." It argued that the types of generating facilities listed in proposed subsection (e)(2) constitute installed generation capacity as defined by PURA §§39.154(d)(1), (2) and (3) and are potentially marketable. It added that these types of generation facilities are potentially marketable because power from such facilities can be sold in the competitive market; thus, they can be used to defeat an attempt to exercise market power. Their existence, therefore, thwarts the exercise of market power.

CSW recommended that if any of the categories are not considered to be potentially marketable, then a legally binding prohibition on sales of such capacity should be adopted, with no exceptions, even during the peak summer months. TIEC disagreed with CSW's recommendation. It argued that such a prohibition is beyond the commission's power to enforce in a deregulated market, and that a prohibition on sales from must-run units would seriously impair the reliability of the power grid.

Reliant interpreted the proposed rule as excluding certain generation capacity from the denominator of the installed generation calculation, but counting the same capacity in the numerator of individual market share calculations. It argued that this would not be conceptually correct and it would only serve to over-estimate market shares of power generation companies.

OPC commented that proper calculation of installed capacity in the state is critical to the development of workable competitive markets. It said that excessive concentration of capacity ownership will lead to the potential for market power which can drive prices up, exploit customers with inelastic demands, and pose barriers to entry of new competitors. OPC said that the protection offered by the 20% capacity market share criteria is diminished somewhat by legally required reductions to installed generation capacity, such as reductions for "grandfathered" facilities and capacity auction sales. It concluded that the concept of potentially marketable capacity should be defined in a conservative fashion.

TIEC and PG&E agreed with all of the exclusions in subsection (e)(2). TIEC stated that including generation that is not available for wholesale sales in the denominator of the market concentration analysis would impair the integrity of the analysis by artificially reducing the market shares of the owners. PG&E suggested that the words "potentially marketable" in this context are used by way of limitation. These words modify examples of categories of generation to be included in the determination of installed generation to be used to measure market power. In other words, only generation capacity that may be sold in the market may be considered in the assessment of market share, which, under the statute, is used as a proxy for measuring market power. PG&E said that the categories identified should be excluded consistent with the intent of the Legislature that only "potentially marketable" generation be considered in the determination of installed capacity.

PG&E proposed that two additional categories of capacity be excluded from installed generation capacity because the capacity is not available for sale at wholesale. PG&E would exclude the capacity necessary to meet the native summer peak demand of municipally owned utilities and cooperatives that have not opted for customer choice; and it would exclude any capacity that is under contract for delivery to another power region.

In reply comments, CSW, EGSI, Reliant, and TXU strongly disagreed with OPC, PG&E and TIEC that the phrase "all potentially marketable" was intended to be a limitation on the definition of "installed generation capacity." CSW said the phrase was used for emphasis and was intended to be inclusive rather than exclusive. EGSI and TXU argued that the words used in PURA §39.154(d) require that the statute be interpreted broadly. TXU said the Legislature intended the term "installed generation capacity" to include all capacity that could be marketed, not just capacity that is being marketed. TXU also said there was no basis in PURA §39.154 for PG&E's recommendations to exclude capacity that is exported to another power region or capacity that is reserved to serve native load of opt out municipal and cooperative utilities. It averred that the fact that this capacity is being sold indicates that it is marketable. Reliant suggested that initially all potentially marketable capacity should be included, and then excluded only if experience proves it not to be marketable.

Also in reply comments, PG&E and TIEC strongly disagreed with CSW, EGSI, Reliant, and TXU. PG&E said that in essence, the incumbent utilities would have the commission render the phrase "potentially marketable" meaningless. PG&E said the commission should identify the capacity that reasonably could be expected to be marketed, and thus, affect market power.

TXU in its comments presented the legislative history of §39.154(d) of Senate Bill 7 (SB7), 76th Legislative Session, and argued that the Legislature intended the term "installed capacity" to include all generation that *could* be marketed, not just generating capacity that *is being* marketed. However, incumbent utilities have not offered any examples of installed capacity that could not be marketed. If there is no capacity that is not potentially marketable, then it would seem that the phrase "potentially marketable" in PURA does not have any meaning.

The commission finds it unnecessary to adopt a prohibition on sales from capacity that has been excluded from installed generation capacity. The commission agrees with Reliant that when capacity is excluded from the denominator, it should also be excluded from the numerator for the power generator that owns and controls such excluded capacity. However, the commission disagrees with Reliant's suggestion that initially all generation facilities should be included in installed generation capacity and then excluded only if experience proves it not to be marketable. The commission makes no changes in response to these particular comments. The specific exclusions in §25.401(e)(2) are addressed below.

§25.401(e)(2)(A): Installed generation capacity will not include generating facilities that have a nameplate rating equal to or less than 1 megawatt (MW).

TXU and SPS pointed out that distributed generation facilities will likely play a significant role in the development of the market in Texas. Therefore, facilities rated at less than 1 MW should not be excluded from the potentially marketable capacity. On the other hand, TIEC commented that generation facilities rated at less than 1 MW are too small to have any meaningful impact on the market, so it is appropriate to exclude them from the denominator. PG&E agreed with the exclusion of these generators, mainly because it would be difficult to monitor every small generator around the state.

In reply comments, PG&E asserted that *de minimis* capacity, such as distributed generation, does not have a great effect on the current market. Reliant replied that Texas is likely to have many generation facilities with one megawatt or less capacity and, in the aggregate, those facilities will have a meaningful impact on market concentration. EGSI added that the phrase "potentially marketable" requires only that generation is capable of being sold, not that it must have a meaningful impact on the market.

In reply comments, TXU disagreed with PG&E that PURA §39.154 would impose a reporting burden on small generators or require the commission to monitor them. TXU expressed confidence that the commission could develop reasonable estimates of the total amount of generating facilities under 1 MW.

Although the commission encourages the development of distributed generation, generating facilities with a capacity of less than 1 MW do not constitute a significant percentage of the installed generation in the state at this time. Therefore, the commission believes it is appropriate to exclude these generating facilities from installed generation capacity in order to simplify the calculation. If it appears in the future that facilities with less than 1 MW capacity contribute significantly to the installed capacity in a power region, the commission may revise the rule appropriately.

§25.401(e)(2)(B): Installed generation capacity will not include generating facilities that are used for backup purposes and do not generate electricity that is sold at wholesale.

SPS disagreed with the exclusion of backup generation. It noted that in May 2000, the Federal Energy Regulatory Commission (FERC) issued interim orders valid until September 30, 2000, to make it easier for large manufacturers to sell their backup power to utilities when electricity supplies run short. PG&E responded that backup power sold to utilities, including power sold pursuant to FERC interim measures, would not be excluded from installed capacity under the proposed rule.

PG&E said it is reasonable to exclude backup generation because in the absence of an interconnection agreement and appropriate interconnection equipment such generation is not deliverable over the grid. It also said that backup generation should be excluded because its availability is limited by TNRCC regulations to 10% of the normal operating hours of the primary equipment being replaced, absent formal air quality permits being obtained. TXU responded that PURA §39.154 does not require capacity to be available 100% of the time. Reliant replied that backup power is potentially marketable since many such units are connected to the grid.

The commission concludes that the category of backup generation is not necessary, and it amends the rule to delete this category. Backup generation that is less than 1 MW will be treated in accordance with subsection (e)(2)(A). Backup generation that is greater than 1 MW is self-generation that may be able to participate in the wholesale market; therefore its treatment will be determined by subsection (e)(2)(C).

§25.401(e)(2)(C): Installed generation capacity will not include generating facilities that are used to generate electricity for consumption by the person owning or controlling the facility and do not generate electricity sold at wholesale.

§25.401(e)(2)(D): Installed generation capacity will not include cogeneration facilities that do not generate electricity that is sold at wholesale.

TXU, Entergy, and SPS opposed the exclusion of self-generation and cogeneration facilities that do not generate electricity that is sold at wholesale. TXU argued that whether or not the generating facilities currently generate electricity that is sold at wholesale does not provide the basis for a determination that the capacity of these facilities is not potentially marketable. PURA §39.154(d) requires only that the capacity be potentially marketable, not that it is currently being marketed at wholesale. It added that excluding the capacity of such generating facilities is contrary to PURA §39.154(d)(2) which expressly includes "generating facilities used to generate electricity for consumption by the person owning or controlling the facility." SPS added that cogenerator status may change through the loss of a steam host; and PURA does not distinguish how potentially marketable capacity is used by the final consumer.

Entergy cited a trade publication article about an aluminum company that had recently decided to sell the output of its cogeneration facility to the grid rather than produce aluminum because the company perceived electricity prices to be more attractive than aluminum prices.

OPC agreed with the rule's recognition that some self-generation and cogeneration capacity is not potentially marketable, but it said one problem with the rule is that a very small sale into the wholesale market could qualify the full capacity of a self-generation or cogeneration facility as installed capacity, even though a large fraction of the facility's capacity is not potentially marketable. OPC proposed an alternative means for determining which self-generation and cogeneration is potentially marketable. It recommended that the portion of self-generation and cogeneration which serves on-site load and is defined as "eligible on-site generation" pursuant to §39.262(k) and Substantive Rule §25.345(i) of this title should be excluded from installed capacity. By this recommendation, capacity would be excluded because it is not economically feasible for a customer to change its self-supply arrangement if the on-site generation facility had qualified for a stranded cost exemption pursuant to §39.262(k).

PG&E commented that by definition self-generation and cogeneration that are not sold at wholesale are by definition not available for purchase in the market. Further, such capacity is not deliverable to the market absent an interconnection agreement and appropriate interconnection equipment. TXU replied that PG&E offered no proof that self-generation and cogeneration facilities do not have or could not get interconnection agreements.

TIEC agreed with OPC that only the portion of self-generation or cogeneration that serves the wholesale market should be included in the total installed capacity in the power region. However, TIEC and other parties disagreed with OPC's recommendation for an alternative definition of which self-generation and cogeneration is potentially marketable. PG&E found OPC's alternative to be too narrow in that it fails to recognize that other self-generation and cogeneration are not potentially marketable even if they do not qualify as eligible generation. TIEC opposed OPC's suggestion, saying that the treatment of on-site generation is more appropriately linked to actual participation in the market rather than a §39.262(k) determination. Reliant disagreed with OPC's argument that competition transition charge (CTC) would preclude self-generators from marketing power. Reliant said that self-generators in service areas without CTC would be able to market power without incurring this charge. TXU noted that OPC offered no proof that the loss of stranded cost exemption would be of sufficient magnitude to prevent the marketing of eligible on-site generation.

The commission amends the rule to delete the exclusions for self-generation and cogeneration. The commission agrees with TXU that whether the generating facilities currently generate electricity that is sold at wholesale does not provide a basis for a determination that the capacity of these facilities is not potentially marketable. The phrase "is available for sale to others" in the initially introduced version of SB7 was replaced by the concept of "potentially marketable" capacity. This is a more liberal standard, and the commission concludes that cogeneration and self-generation facilities meet this standard. Section 39.154, as finally enacted, casts a wide net on the generation facilities that are included in determining the size of the market.

§25.401(e)(2)(E): Installed generation capacity will not include generating facilities that will be retired within 12 months.

Reliant and SPS opposed the exclusion of generating facilities that are scheduled to be retired within 12 months. Reliant commented that there is no mandatory or regulatory requirement in a competitive market that any unit actually be retired. Further, changes in market conditions or unanticipated unit outages might require operation of a facility that had been previously scheduled for retirement. Moreover, information on planned retirements in a competitive environment is considered strategically sensitive information and forecasts of retirements could be subject to "gaming". TXU agreed that plans to retire a generating facility can be changed in response to market conditions.

PG&E supported the exclusion of capacity that will soon be retired because such capacity will no longer mitigate market power and because the exclusion provides consistency and symmetry in the determination of market shares. TXU responded that if the Legislature had wanted to provide symmetry it could have done so.

OPC also supported the exclusion of capacity that will soon be retired, but suggested that the word "permanently" be added before the word "retired" to alleviate the potential for manipulation of retirement plans by plant owners. PG&E agreed with OPC's recommendation but TIEC opposed it. TIEC proffered that if a unit is returned to service after being retired, it should be included in any market concentration analysis after its return to service.

The commission agrees with Reliant and TXU that in a competitive market, plans to retire a generating facility may be fluid and responsive to market conditions or changes in the status of other generating equipment. In addition, the commission is concerned about the potential for gaming retirement plans in order to manipulate market shares or mask competitively sensitive resource plans. Finally, in the last year, the commission has witnessed a regulated utility return several generating units to service in order to provide adequate resources for its system. These units were returned to service in a relatively short time, and it is fully plausible that they could provide marketable capacity in a future competitive market. Therefore, the commission amends the proposed rule to remove the exclusion for generating facilities that will be retired within 12 months.

§25.401(e)(2)(F): Installed generation capacity will not include generating facilities that have been designated as "grandfathered" pursuant to subsection (d)(3) of this section.

OPC, PG&E, and TIEC concurred that "grandfathered" facilities must be excluded from the denominator as well as the numerator. They said that while PURA §39.154(e) is silent with respect to the denominator, this does not preclude the commission from excluding such facilities from the denominator. They added that if numerator and denominator are defined inconsistently, the summation of Electric Reliability Council of Texas (ERCOT) market shares will not equal 100%. Thus, market shares and market power would be understated. They argued that the Legislature did not intend an illogical mathematical operation, and that it did not intend to undermine its own stated policy to limit market share and to eliminate market power abuses.

Reliant and TXU disagreed that the total of all market shares must add to 100%. They said that the Legislature knew the shares would not add to 100%, but wanted to provide an incentive in §39.154(e) for a PGC to comply with §39.264. Rather than understating market shares, Reliant and EGSI said that excluding grandfathered facilities from the denominator would overstate the market shares of those generators who do not have grandfathered facilities.

TXU, EGSI, and Reliant said that excluding grandfathered facilities from the denominator is contrary to the statutorily-prescribed method of determining the percentage shares of installed generating capacity. They argued that by expressly stating that the commission shall reduce the numerator by the amount of such capacity, the Legislature clearly implied that the denominator is not to be reduced by the amount of such capacity. They observed that SB7 contemplated that the sum of all the percentage shares for a power region would not equal 100% because PURA §39.154(c) requires that the installed generation capacity subject to auction pursuant to §39.153 be subtracted from the numerator.

PG&E said that the exclusion of grandfathered facilities from the determination of installed capacity reasonably harmonizes the competing legislative policies related to market power and environmental issues. PG&E acknowledged that capacity auction requirements would result in market shares failing to sum to 100%, but it argued that excluding grandfathered capacity is more likely to achieve the Legislature's market power policy objectives than the alternative which would understate market shares and market power without providing any benefit to the competing environmental objective.

The commission deletes the provision that excludes grandfathered facilities from the denominator. The commission believes that these plants legitimately contribute to total market generation and should be counted in the denominator. However, the record is this rulemaking includes an August 9, 2000 letter from TXU Electric Company in which TXU proposes a compromise concerning the exclusion of grandfathered facilities. TXU proposed that if the commission deletes the proposed section related to the exclusion of grandfathered facilities, then TXU would refrain from acquiring ownership and control of additional generating facilities to the extent that such acquisition would cause TXU to exceed SB7 20% limitation of ownership and control, calculated with the capacity of all grandfathered facilities excluded from both the numerator and denominator of the equation. The commission accepts TXU's proposal.

§25.401(e)(2)(G): Installed generation capacity will not include generating capacity that has been designated "must-run" by the independent organization in the power region.

SPS opposed the exclusion of must-run capacity, arguing that even must-run units are potentially marketable since the output is sold to and for the benefit of the power region.

Noting that the treatment of must-run generation is still under discussion in ERCOT, TIEC commented that such generators will likely be required to sell their power at regulated prices. Thus, the ability of must-run generation to influence market behavior or competitive market prices will be restricted. Therefore, it is appropriate to exclude must-run generation from the denominator of the market concentration calculations.

PG&E also supported the exclusion of must-run capacity. It said that must-run capacity provides system support to ensure the reliability of the system, but it is not available to provide energy for sale at wholesale. However, since must-run generation will vary over time as generation and transmission facilities are added to the system, PG&E suggested that must-run units should be designated annually to coincide with the determination of market shares.

In reply comments, Reliant argued that if the rule excludes must-run capacity from the denominator, it should also allow PGCs to exclude their "must run" capacity from the numerator as well.

The commission agrees with SPS that the output of a "must-run" unit is sold to and for the benefit of the power region. The fact that the independent system operator (ISO) can control the output of a must-run unit in market-crucial periods means that the availability of a must-run unit clearly and directly moderates other players' ability to limit generation to influence the market clearing price. Under current plans in ERCOT, the ISO will purchase must-run capacity under contract. Therefore the commission concludes it is appropriate to delete the exclusion of must-run capacity from the market share denominator, as it is to include a company's must-run capacity in calculating its market share numerator.

§25.90 Market Power Mitigation Plans

§25.90(a), Application

CSW proposed the addition of a sentence to the end of §25.90(a) permitting the commission, for good cause, to waive or modify the requirement to file a market power mitigation plan, in accordance with PURA §39.154(b).

The commission has made the change recommended by CSW.

EPE commented that by virtue of PURA §39.102(c), it is not subject to PURA Chapter 39 until the expiration of its freeze period in 2005. It requested that proposed §25.90 be amended to reflect this fact.

The commission has made the change recommended by EPE.

Entergy, Reliant, and TXU argued that the actual date of relevance for the 20% test should be on or after January 1, 2002, not the December 1, 2000 date in the proposed rules. Reliant and TXU stated that PURA §39.154 clearly states that the date on which the 20% limitation on installed capacity begins is the "date of introduction of customer choice." TXU stated that the Legislature clearly intended the ownership and control determinations to be forward-looking since new generating facilities that will be operating within 12 months are to be included as part of installed generation capacity. TXU noted that the commission has projected that more than 14,000 megawatts of new generation capacity is expected to come on-line in ERCOT by the first year of customer choice, and that the new generating capacity will substantially alter percentage shares of installed generation capacity. TXU and Reliant said the percentage shares of installed generation capacity should be determined based on projections or estimates of the total amount of installed generation capacity expected to exist in each power region on the date of introduction of customer choice.

PG&E and TIEC disagreed with the incumbent utilities, urging the commission to keep the December 1, 2000 date. PG&E argued that changing the operative date for measuring market share would be contrary to PURA §39.156(b). TIEC stated that using projected generation data would introduce a great deal of uncertainty and controversy in the market concentration analysis, because it is likely that parties will produce widely divergent forecasts of the amount of generation that will be added by various generation owners in the future.

The commission agrees with Entergy, TXU and Reliant that it is not appropriate to specify in the rule that a utility that has a capacity market share greater than 20% prior to December 1, 2000 will be required to file a market power mitigation plan by December 1, 2000. The focus of the rule should be on market shares when retail competition begins. Therefore, the commission deletes the phrase "prior to December 1, 2000" from §25.90(a). However, the commission does not believe it is appropriate to include language that specifies the use of projected data; therefore, it declines to make the other wording changes recommended by TXU.

The commission included the initial information filing in §25.90(b) of the proposed rule to provide enough information so that it can calculate market share percentages to determine which utilities, if any, will be required to file a market power mitigation plan by December 1, 2000. In calculating market share percentages, the commission will consider generating facilities that will be connected to a transmission and distribution system and operating within 12 months as required by PURA

§39.154(d)(3). The commission recognizes that there may be differing expectations of the capacity that will be connected and operating within 12 months, but it will work with the appropriate ISOs to determine appropriate estimates for the amount of incremental generation capacity to be included.

§25.90(b), Initial informational filing

CSW commented that the rule does not set forth the basis for determining the capacity rating of a generating unit. It suggested that nameplate rating is the appropriate method.

The commission adds a reference in §25.90(b) to §25.91(f) of this title (relating to Generating Capacity Reports) where the basis for determining the capacity rating of a generating unit is set forth.

Entergy and TXU commented that the proposed initial information filing in §25.90(b) is not expressly required by PURA and that it serves no useful purpose. TXU added that if the informational filing requirement is retained, it should be broadened to include all persons subject to PURA §39.155 since there is no basis in PURA for discrimination based on the amount of installed generation capacity owned and controlled. It pointed out that PURA §39.001(c) provides that the commission may not discriminate against any participant or type of participant during the transition to and in the competitive market.

PG&E and TIEC strongly dissented, stating that the reporting requirement is vital for enforcing the statutory limit on generation ownership. In addition, they believe that to require all generation owners to file market share calculations would impose an administrative burden on smaller generation owners with no useful purpose.

The commission believes that the initial filing requirement is necessary so that it can calculate market share percentages and determine which utilities or power generation companies, if any, should file market power mitigation plans on December 1, 2000. However, it would not serve any purpose to broaden the filing requirement to include all persons subject to PURA §39.155 since most of them would not come close to having a 20% capacity market share. The commission does not agree that it is discriminatory to require an informational filing from the small number of utilities that have the greatest amounts of installed generation so that it can determine who should file market power mitigation plans. The informational filing is necessary for the commission to meet its responsibilities to ensure that no one has a market share greater than 20%.

TXU recommended that the phrase "in the power region" in §25.90(b) should be modified to read "in the power region, or capable of delivering electricity to the power region" to be consistent with the language in PURA §39.154(a). It also commented that the phrase "owned in whole or in part" is inconsistent with PURA §39.154 and should be modified to read "owned and controlled."

The commission agrees with TXU and has made the recommended changes.

TXU recommended that transmission import capacity be excluded from both the numerator and denominator of the market concentration analysis because including it would be inconsistent with PURA §39.154(a). It pointed out that "installed generation capacity" is defined as all potentially marketable electric generation capacity, and therefore it is inappropriate to include transmission import capacity in the calculation. Reliant and Entergy suggested that the commission should retain transmission import capacity in the denominator of the analysis, while excluding such capacity from the numerator because open access transmission allows nondiscriminatory access to transmission capacity on a first-come, first-served basis.

TIEC opposed these suggestions, stating that it is entirely appropriate to include transmission import capacity in the numerator or denominator of the market concentration analysis, because the ability to import generation into a region has a direct impact on competitive market prices within the region. It said the existence of open-access transmission does not negate the fact that generation owners can control transmission import capacity by reserving such capacity under the tariffs. TIEC added that including transmission import capacity in the denominator but not in the numerator of the market concentration analysis would artificially reduce the market shares of the generation owners.

CSW recommended that transmission import capacity amounts that are to be included in the numerator and the denominator of the calculations should be reported by the ISOs rather than the utility or power generation company.

The commission believes that the inclusion of transmission import capacity in the market share calculation is entirely consistent with the language in PURA §39.154 which refers to capability of delivering electricity to a power region. It believes that inclusion of transmission import capacity in the denominator is necessary in order to accurately determine the value of the total installed generation capacity that is available in a region. Similarly, the commission believes that the transmission capacity that a utility or power generation company reserves in order to import generation capacity owned and controlled in another power region should be included in the numerator of the market share calculation. The commission adds wording to the section to clarify the information that should be included in the initial informational filing, and to allow any interested party to respond to the initial informational filings.

Entergy stated that if the commission chooses to include import capacity, at a minimum, only the amount directly reserved by the power generation company should be included. Entergy said that continuing regulatory obligations may require that its regulated affiliates reserve transmission import capacity to support ongoing regulated retail load. It noted that utilities in regions that have not fully deregulated may need to reserve transmission capacity in order to meet retained regulated load obligations. Entergy continued by stating that certain types of transmission reservations may be properly assigned to a supplier, such as reservations associated with long-term power contracts. In this case, it said the supplier has "control" over the reserved amount of import capacity that can serve the power region. However, it added, other types of transmission reservations should not automatically be assigned to the current holder of the reservations.

As discussed in its comments concerning §25.401(d), the commission believes that a utility's numerator capacity share should include the transmission import capability that is reserved for the purpose of importing generation capacity during the summer peak season that is owned and controlled by the power generation company or its affiliate in another power region.

§25.90(c), Market power mitigation plan

SPS recommended that the ability to increase transmission capability into a power region be added as a recognized mitigation measure that may be included in a market power mitigation plan. PG&E disagreed, stating that the addition of transmission capacity does not represent a reasonable market power mitigation measure because it would impose costs on other market participants that otherwise could be avoided. It argued that the addition of transmission capacity can add costs to the nonbypassable charges. It added that in power regions other than ERCOT, transmission rates are subject to FERC jurisdiction and may not be determined based on the postage stamp approach. Thus, generation which is closer in proximity to load, *i.e.*, incumbent utility generation, would have a market advantage in that its transportation costs would be lower than the transportation costs to its competitors.

The commission declines to make the changes recommended by SPS. PURA §39.156(c)(5) states that a proposed market power mitigation plan may include any reasonable method of mitigation. SPS or other entity will be free to include a proposal to mitigate market power by increasing transmission capability in the plan it proposes. The merits of such a proposal can be taken up at that time.

§25.90(f), Commission determinations

Subsection (f)(5)

Reliant and TXU contended that whether a plan provides adequate mitigation of market power is not a relevant consideration in evaluating a proposed market power mitigation plan. They pointed out that PURA §39.156(a) defines a market power mitigation plan as a proposal for reducing ownership and control of installed generation capacity. Reliant averred that while other sections of PURA do give the commission the authority to monitor market power and address market power abuses, those issues cannot be the subject of a plan filed under PURA §39.156 and proposed §25.90, nor can the commission assume broader discretion in considering market power mitigation plans than is provided for in PURA §39.156(g).

In reply comments, PG&E and TIEC countered that the TXU and Reliant position should be rejected because §39.156(g)(5) of PURA provides that the commission may consider whether a plan is consistent with the public interest in evaluating a market power mitigation plan. TIEC stated that these responsibilities extend beyond the determination of whether generation capacity is excessively concentrated to include the detection and mitigation of a variety of market power abuses, including predatory pricing, collusion, withholding of capacity, and erecting barriers to market entry. It added that whether a proposed plan adequately mitigates market power is directly relevant to evaluating a market power mitigation plan and should be retained in the rule.

The commission does not agree that PURA §39.156 limits it in the manner suggested by Reliant and TXU. PURA §39.156(g) expands the commission's determinations beyond the sole issue of the proposed reduction in ownership and control of installed generation capacity to include such issues as minimization of stranded costs, the effect on federal income taxes, and consistency with the public interest. The commission agrees with PG&E and TIEC that in considering whether a plan is consistent with the public interest, it can make a determination of whether the plan provides adequate mitigation of market power. In determining whether there is adequate mitigation, the commission will look to whether the utility or power generation company has presented a feasible and timely plan to reduce generation to below the 20% threshold. The commission declines to make the changes recommended by TXU and Reliant.

Proposed Subsection (f)(7)

SPS suggested that language should be added to §25.90 as (f)(7) to indicate "whether the sale of capacity or disposition of assets is subject to federal Securities and Exchange Commission pooling of interests requirements."

The commission declines to add the language recommended by SPS. SEC pooling of interest requirements are not related to market power or the public interest determination in evaluating market power mitigation plans.

§25.91 Generating Capacity Reports

§25.91(a), Application

EGSI, Reliant, and SPS commented that the application in §25.91(a) should pertain to all generators connected to the transmission or distribution system, including self-generation and cogeneration. TIEC strongly opposed a requirement for self-generators and cogenerators to file generating capacity reports if they do not offer power for sale in the market. It argued that generation that is not for sale will not affect market prices; therefore, reports from such generators are not needed to assess market power.

The commission declines to make the change recommended by EGSI, Reliant, and SPS. The proposed rule is consistent with PURA §39.155(a), which requires entities that own generation facilities and offer electricity for sale in the state to file generating capacity reports.

EPE recommended that language be added to §25.91 stating that the section would not apply to an electric utility that is not subject to PURA Chapter 39, pursuant to PURA §39.102(c), until the expiration of its freeze period.

The commission agrees that the rule does not apply to a company that is subject to PURA §39.102(c) until its freeze period ends. The commission modifies §25.91(a) to include this clarification; however, it notes that EPE will continue to be subject to other applicable commission reporting requirements during the freeze period that are not based on PURA Chapter 39.

§25.91(b), Definitions

CSW commented that the defined term "net dependable capability" (NDC) in §25.91(b) and the reference to "summer net dependable capability" §25.91(f) will be subject to a variety of interpretations which will lead to inconsistencies in the calculations made by various reporting entities. CSW recommended the use of nameplate ratings that it said would be more easily determined and verified.

PG&E replied that NDC provides a more accurate measure of the capacity available during peak periods when the potential for market power abuses is at its highest. However, PG&E would not object to modifying the definition of "summer net dependable capability" to provide more uniformity in its determination.

The commission believes it is appropriate to measure capacity that is available during peak periods when the potential for market power abuse is at its highest. NDC rating is a well-established requirement in ERCOT, and the commission believes that other reliability councils have comparable requirements although they may use slightly different terms. Therefore, the commission modifies the definition of "summer net dependable capability" to mean the net capability of a generating unit for daily planning and operational purposes during the summer peak season, as determined in accordance with the requirement of the reliability council or independent organization in which the unit operates.

Reliant recommended the use of nameplate capacity ratings in §25.91(b)(1) for renewable generators instead of some historical operating measure. It noted that the output of renewable resources varies from year to year, which would yield an inconsistent measure of installed capacity.

Although the actual peak capacity provided by a renewable generator may vary from year to year, the year-to-year difference may be much less than the difference between the nameplate rating and the actual performance. Some renewable generation relies on intermittent resources, such as wind, and have significantly less real capability than their nameplate capacity. Therefore, the commission believes the historical measure is a more appropriate measure of the capacity of a renewable resource, and declines to make the change recommended by Reliant.

§25.91(c), Filing requirements

EGSI commented that filing such a broad list of operational measures on an annual basis is burdensome and inconsistent with the spirit of competition. SPS recommended that the reporting date be moved from the end of February to May 15th or later to allow companies to incorporate information from their FERC Form 1 reports.

The commission does not agree that annual filing of the information required by this rule is burdensome. Information filed on a less frequent basis would not be timely enough to be of value. In addition, to the extent that market power abuse issues arise, they are likely to occur during the summer peak period. An annual filing made on May 15th or later would be received too late for the commission to evaluate the information and take any needed actions prior to the summer peak season. Therefore, the commission declines to make the changes recommended by EGSI and SPS.

§25.91(e), Confidentiality

TXU commented that the use of a standard protective order as provided in §25.91(e) is not appropriate because the generating capacity reports will not be filed as part of a contested proceeding. It recommended that §25.91(e) should permit reporting parties to designate information as "competitively sensitive" since PURA §39.155(a) requires the commission to administer the reporting requirements in a manner that "ensures" the confidentiality of "competitively sensitive information." TXU also recommended the rule should expressly state that information designated as "competitively sensitive" shall be considered exempt from the disclosure requirements of Chapter 552, Government Code. TXU noted that Government Code §552.110 exempts from disclosure "commercial or financial information obtained from a person and privileged or confidential by statute…"

PURA §39.155(a) requires the commission to administer the reporting requirements "in a manner that ensures the confidentiality of competitively sensitive information." This requirement is not equivalent to saying that information filed automatically qualifies for an exemption from the Open Records act. Government Code §552.110 states that "a trade secret or commercial or financial information obtained from a person and privileged or confidential by statute or judicial decision is excepted from the requirements of §552.021." The commission does not agree that the information to be submitted in the generating capacity reports becomes "privileged or confidential by statute or judicial decision" by virtue of being submitted pursuant to PURA §39.155(a). Therefore, the commission declines to make the changes recommended by TXU.

§25.91(g), Reporting requirements

EGSI commented that much of the information requested in §25.91(g) is unnecessary and unduly burdensome. It recommended the information only be required when there is evidence of market power abuse or a complaint is filed alleging market power abuse. In reply comments, PG&E said that the reporting requirements should be retained, except for the highly sensitive competitive information in §25.91(g)(2)(H)-(L), to help the commission perform market monitoring and ensure compliance with the requirements of PURA, including the 20% limitation on the ownership of capacity.

Based on amendments made pursuant to comments, the commission does not believe that the revised information required in §25.91(g) is unnecessary and unduly burdensome. It notes that PURA §39.155(a) requires generating entities to report "any other information necessary for the commission to assess market power or the development of a competitive retail market in the state." The commission has reviewed the comments and reply comments on specific subparts of the proposed rule and will address them in the following paragraphs.

Alcoa and OxyChem commented that the proposed rule imposes a much greater burden on cogenerators than the prior requirements in P.U.C. Substantive Rule §25.105 of this title. They were very concerned about the amount of information, especially the highly confidential information, that would have to be reported on an annual basis. They argued that cogenerators should continue to report according to the §25.105 requirements, and that additional data should only be required when there is a complaint by a market participant that an abuse of market power has or is likely to occur. FPLE and PGCs expressed the same concerns on behalf of EWGs as well as cogenerators and recommended that EWGs and cogenerators also should continue to report according to the §25.105 requirements.

When it revised Substantive Rule §25.105, the commission intended to simplify the registration requirements for power generation companies and to consolidate the reporting requirements in a separate rule. The commission believes that annual reporting is necessary because the commission is charged with monitoring capacity market shares and market power. It is likely that some of the information to be reported annually may not change significantly from year to year. Therefore, the reporting requirements may be less burdensome than they appear.

FPLE also argued that even if the requirements in the proposed rule are appropriate for incumbent utilities in Texas or their generation affiliates, they are not appropriate for independent power generation companies which are just entering the market in Texas and cannot wield market power. CSW and Reliant replied that a distinction in reporting requirements for small or non-affiliated owners of generation capacity would not be consistent with statutory provisions, and it would unfairly disadvantage those entities that are required to file extensive reports. CSW added that such a distinction would limit the commission's ability to monitor and evaluate market power. Reliant added that PURA §39.001(c) prohibits the commission from discriminating against any market participant or type of market participant during the transition to a competitive market or in the competitive market.

The commission does not agree that it would be appropriate to have separate reporting requirements for generating entities that are not affiliated with incumbent utilities in the state. Independent PGCs and new entrants can accumulate generation market share quickly, whether through construction or acquisition. All power generation companies should file the same generating capacity reports. Market power abuse may occur in a localized area and may not be a function of the total amount of generation in a power region. Therefore, the commission declines to make any changes in response to FPLE's comments.

Subsection (g)(1)

PG&E recommended two additional categories of information be required in §25.91(g)(1). First, it recommended that parties report total capacity under contract to affiliates from unaffiliated entities so the commission can better monitor the total capacity controlled by a single affiliate group. Second, it recommended that parties report affiliate capacity that will be connected to a transmission or distribution system within 12 months so the commission would have better information on the capacity owned by a single group. In reply comments, Reliant argued that both categories are unnecessary since the commission will already have the information. It pointed out that PGCs must identify wholesale and retail electric affiliates in Texas when they register with the commission pursuant to Substantive Rule

§25.109 of this title, and that all entities that generate electricity for sale in the state will file the capacity reports to be approved in §25.91.

The commission agrees with Reliant that the information requested by PG&E could be determined from the information filed under Substantive Rule §25.109 of this title and proposed §25.91. The commission declines to make the changes recommended by PG&E.

TXU Electric proposed adding a new subpart under §25.91(g)(1) that would require reporting parties to provide the capacity of generating facilities used to generate electricity for consumption by the person owning or controlling the facility. It argued that this is necessary to be consistent with the definition of "installed generation capacity" in PURA §39.154(d).

The commission agrees and makes the change proposed by TXU.

CSW requested clarification of whether the phrase "capacity dedicated to its own use" in §25.91(g)(1)(F) referred to data on power plant consumption.

Subsection (f) of this section provides that generating unit capacity will be reported at the summer net dependable capability. This value would be net of power plant consumption. The commission intends that self generators report the amount of capacity that they have reserved for their own use in response to subsection (g)(1)(F).

SPS and Reliant argued that subsection (g)(1)(H) should be deleted because there is no reason to risk inadvertent exposure of confidential, unit-specific information that is not needed for market monitoring purposes. They also argued that subsection (g)(1)(I) and (L) should be deleted because annual energy and capacity sales to affiliated REPs are not relevant to the determination of total market share. In reply comments, PG&E argued that the information in (g)(1) can be required pursuant to PURA §39.155(a); it said the reporting requirement should be retained since it is designed to facilitate the commission's market monitoring function.

Consistent with the commission's conclusion that anticipated plant retirements will not be excluded from the market share denominator, the rule is amended to delete this reporting requirement from the generating capacity reports. However, the commission believes that information on capacity and energy sales to affiliated REPs is necessary for market oversight purposes. Therefore, the commission declines to make the change recommended by Reliant.

SPS commented that the word "energy" in §25.91(g)(1)(J) and (K) should be changed to "power" to conform to PURA §39.155(a).

Although PURA uses the term "power," the commission believes that the term "energy" is more commonly used in this context. Therefore, the commission declines to make the change recommended by SPS.

Subsection (g)(2)

Alcoa, CSW, FPLE, OxyChem, PGCs, Reliant, SPS, TIEC, and TXU strenuously objected to subparagraphs (H) through (L) because they would require routine reporting of information that the parties view as highly confidential and competitively sensitive. In addition, the parties argued that the information in subparagraphs (H) through (L) is not needed by the commission to assess market power or the development of a competitive retail market in the state. Reliant and SPS also objected to subparagraph (M) for the same reasons. AE objected to all of paragraph (g)(2) for the same reasons.

OxyChem, PGCs, and TIEC argued that the information specified in subparagraphs (H) through (L) is particularly sensitive for industrial cogenerators and self-generators. TIEC said that information such as heat rate provides critical cost information that would allow a competitor to ascertain not only the cost of electricity for an industrial customer with self-generation, but also the production cost for the products made by that company. It said that for some industries that use self-generation or cogeneration, electricity comprises up to 70% of their production costs. FPLE and PGCs stressed that there would be no assurance that competing generators or prospective buyers could not obtain the information through the Open Records Act. Reliant and TXU commented that even though the reports could be filed under a protective order, there was a risk that the information could be disclosed inadvertently.

CSW, EGSI, OxyChem, PGCs, and PG&E argued that the information in subparagraphs (H)-(L) should only be required if the commission had a specific need for it, such as investigating a complaint of market power abuse. PGCs and PG&E said the commission has sufficient authority under PURA to require this kind of data from any generator against whom a complaint has been lodged of potential market power abuse.

SPS recommended that if the commission deems the information in subparagraphs (H) through (M) to be necessary, then it should adopt a standard reporting format such as that provided to the North American Electric Reliability Council.

CPS, CSW, OxyChem, PGCs, PG&E, and TIEC acknowledged the commission's responsibility to monitor market power and its authority under PURA §39.155(a) to require reporting of "any other information necessary for the commission to assess market power or the development of a competitive retail market in the state." CPS suggested that such assessments might be better achieved through the establishment of an effective market monitoring program in conjunction with the ERCOT ISO (or the independent organizations in non-ERCOT regions). FPLE recommended that the commission obtain generating data through the Package 3 data collection processes being developed by the ERCOT ISO.

PGCs supported FPLE's recommendation, provided that any information obtained from the ISO could be submitted pursuant to a protective order.

PG&E said the commission should not defer to the ERCOT data collection process for determining whether market power abuses have occurred. It said the commission's reporting requirements are designed to facilitate monitoring the market and mitigating any market power abuses and, therefore, the requirements should be retained.

The commission does not agree that all of the information in subsection (g)(2) is highly confidential, competitively sensitive information, but it acknowledges the concern expressed by all the parties about the sensitivity of the information specified in subparagraphs (H) through (M). The commission agrees that it would be more appropriate to require this information only if it is needed for an investigation of possible market power abuse. Therefore, the commission deletes proposed subparagraphs (H) through (M) and adds a new subsection (h) that would require reporting parties upon request to provide additional information to the commission within 15 days.

At this time, the commission declines to adopt the recommendations by CPS and FPLE to rely upon the market monitoring process or the ERCOT Package 3 database for all information beyond the minimum generation capacity share data. The ERCOT database is still in development, and the scope of the commission's market surveillance function has not yet been fully determined. Once those processes are in place, the commission will revisit this provision.

Subsection (g)(3)

SPS commented that it was not clear if subsection (g)(3) was meant to apply to generation that is used on-site or sold at retail only.

Based on the commission's decision concerning §25.401(e)(2) to include, rather than exclude grid-connected self-generation and cogeneration greater than 1 MW in the market share denominator, it is not necessary for parties to file this information as part of their generating capacity reports. The commission amends the proposed rule to delete the requirement.

Subsection (g)(5)

Section 25.91(g)(5) requires a reporting party to provide an explanation of generation that it owns but does not control. PGCs expressed concern that a detailed description of contractual rights and responsibilities would constitute highly confidential and competitively-sensitive information that should not be required.

For purposes of this reporting requirement, a brief explanation of the other party's control of the generating unit will be adequate. The commission is not seeking a detailed description of contractual rights and responsibilities. The commission amends the provision to clarify this point.

Subsection (g)(8)

SPS and Reliant recommended that subsection (g)(8) be deleted because must-run unit status is not relevant to the determination of market shares.

The commission deletes this information requirement because it has determined that must-run capacity will be included in installed generation capacity for the power region. Therefore, it is not necessary to have must-run capacity reported.

Subsection (g)(9)

CSW commented that information on the amount of transmission import capacity in §25.91(g)(9) is "more appropriately" obtained from the entity that supervises the applicable power region.

The commission declines to make the change recommended by CSW. Although the independent organization for the power region would likely be a good source of information on transmission import capacity, the commission's authority to require this information from independent organizations for power regions that include other states is not clear.

SPS and Reliant recommended that subsection (g)(9) be deleted because transmission import capacity is not relevant to the determination of capacity market shares, unless a PGC purchases electricity from itself or an affiliate outside the power region.

The commission declines to make the change recommended by SPS and Reliant. Subsection (g)(9) will provide information that the commission will need in order to calculate generation market shares in accordance with proposed §25.401.

§25.401 Share of Installed Capacity

All comments concerning §25.401(e)(2)(A) – (G) are summarized in the prior section of this document that discusses the published preamble question.

§25.401(a), Application

TXU commented that §25.401 must apply to persons, municipally owned utilities, electric cooperatives, and river authorities that own generating facilities and offer electricity for sale in the state because

§25.401 provides the definition of "installed generation capacity" that is used in proposed §25.90 and §25.91.

The commission does not believe it is necessary to include the other generators in the application section in order for this rule to incorporate by reference the definition of "installed generation capacity" in another rule. The commission declines to make the change recommended by TXU.

§25.401(c), Capacity ratings

Reliant suggested changing the last line of proposed §25.401(c) to say, "The commission may revise reported capacity estimates if they are found to be substantially incorrect and contrary to known published estimates." It said that estimates of net dependable capability for cogenerators, for example, are proprietary in nature, and therefore existing utilities and their affiliate PGCs should not be held accountable for small differences or even transitory changes in capacity estimates.

The commission declines to make the change recommended by Reliant because it is not necessary. The purpose of the last sentence in §25.401(c) is to clarify that the commission will not be obligated to use the submitted capacity ratings if it determines that they are incorrect. The sentence does not automatically attach blame or consequences to the party who submits capacity ratings that are subsequently changed by the commission.

§25.401(d), Installed generation capacity of a power generation company

TXU recommended that the proposed language should be clarified by adding the phrase "that is produced by installed generation capacity owned and controlled by such power generation company" to the end of proposed §25.401(d)(2). It said this is necessary for consistency with PURA §39.154(a).

Reliant and SPS argued that transmission import capacity reserved by a power generation company should not be considered a part of its generating capacity as currently stated in §25.401(d)(2). They noted that transmission is reserved through open access rules, and that transmission may be reserved for many reasons including ancillary services. SPS averred that transmission reservation during the summer peak period will have little to do with market power. SPS argued that transmission reservation is only important if the power generation company has to purchase electricity from itself or an affiliate outside the power region; in which case, such purchase would be considered in the power generation company's market share calculation, and the transmission reservation would be considered in the total power region calculation under the category "capable of delivering electricity to, the power region."

The commission generally agrees with SPS. The numerator of the capacity share calculation should include the transmission capacity that is reserved for the purpose of importing generation capacity that is owned by the power generation company or an affiliate in another power region. The commission amends §25.401(d)(2) accordingly.

TXU proposed that an electric utility or power generation company be allowed to provide evidence other than a Texas Natural Resource Conservation Commission (TNRCC) permit application to demonstrate that it has committed to complying with PURA §39.264. TIEC commented that the mere filing of an application with the TNRCC should not be considered a binding commitment to comply with PURA §39.264 since an applicant can withdraw its application prior to approval. TIEC recommended therefore that grandfathered facilities only be excluded from the determination of market share if the PGC's TNRCC application has been approved. In addition, TIEC recommended that the derated capacity of grandfathered units after pollution control equipment has been added should be used for the market concentration analysis.

In reply comments, TIEC urged the commission to reject TXU's proposal to allow the submission of evidence other than the TNRCC permit application. TIEC noted that it was not clear what evidence TXU had in mind, but it reiterated its initial comments that only an approved TNRCC application would constitute a binding commitment and justify the exclusion of the grandfathered capacity from the market share calculation. PG&E agreed with TIEC. As an alternative, it said the rule could provide that the filing of a TNRCC application would only be considered a binding commitment if the PGC agreed not to withdraw the application without the express consent of the commission.

The commission understands that a grandfathered facility must receive a permit for the emission of air contaminants from TNRCC or it will not be allowed to operate after May 1, 2003. Therefore, submission of a permit application will be considered adequate evidence of a binding commitment to comply with PURA §39.264. However, the commission will review the progress on achieving an approved TNRCC application when it determines market share percentages. If adequate progress has not been made, the commission may chose not to exclude the grandfathered facility from the numerator of the market share calculation. The commission amends proposed §25.401(d)(3) to require that adequate progress must be shown. It also amends proposed §25.91 to require that a utility report on its progress as part of its annual Generating Capacity Report. The commission declines the recommendations made by TXU, PG&E, and TIEC.

§25.401(e), Total installed generation

EGSI and TXU commented that the capacity of generating facilities located on the boundary between two power regions should not be allocated between the regions as currently stated in subsection (e)(1)(D). EGSI said that capacity would be sold into either power region based on prices. TXU said the entire capacity of a boundary facility should be included in the installed generation capacity for each power region because it is potentially marketable in either region. Reliant argued that allocating the capacity of a dual-sited generation facility based on historical sales is flawed logic because the previous year has no bearing on future sales.

TIEC argued that the allocation of capacity from generation facilities on the boundary between two power regions should reflect any firm commitments of power from such facilities. To the extent the facility has a firm contract to supply specific amounts of power to customers within a given power region during the study period, the amount of power committed under the contract should be assigned to that power region for the market concentration analysis.

In reply comments, PG&E agreed with TIEC. It disagreed with EGSI, Reliant, and TXU, pointing out that if both power regions are constrained, which is not unlikely during the peak period, the total capacity is not available to both regions to mitigate market power. CSW agreed with EGSI, arguing that allocation based upon historical data would be of little value because such data would be of little value with respect to capacity under different market conditions. It said such capacity should be included in the denominator for both power regions. Also in reply comments, TIEC said that including the entire capacity in both regions results in obvious double-counting of the same capacity.

The commission believes it is appropriate to allocate the capacity as stated in the proposed rule. Historical information is an imperfect predictor of the future, but it is preferable to double-counting the capacity.

TIEC recommended that the commission establish an appropriate method of determining total transmission import capacity. For example, total import capacity could be defined either be a transmission connection's thermal rating or by the connection's total transmission capability as reported on the regional Open Access Same Time Information System. TIEC said this issue merits further study to determine the appropriate approach.

The commission agrees that this issue needs further study, and it makes no change to the proposed rule.

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

These new sections are adopted under the Public Utility Regulatory Act, Texas Utilities Code Annotated §14.002 (Vernon 1998, Supplement 2000) (PURA), which provides the Public Utility Commission with the authority to make and enforce rules reasonably required in the exercise of its powers and jurisdiction; and specifically, PURA §39.154, which requires the commission to determine the percentage shares of installed generation capacity that are owned and controlled by a utility or a power generation company; §39.155, which grants the commission the authority to assess market power and to require the filing of generation capacity reports; §39.156, which grants the commission the authority to require the filing of market power mitigation plans; and §39.157, which grants the commission the authority to address market power and to monitor the market shares of installed generation capacity to ensure that the limitations in PURA §39.154 (relating to Limitation of Ownership of Installed Capacity) are not exceeded.

Cross Reference to Statutes: Public Utility Regulatory Act §§14.002, 14.003, 31.002, 39.154, 39.155, 39.156, 39.157, and 39.264.

§25.90. Market Power Mitigation Plans.

(a) **Application.** An electric utility or power generation company that the commission determines owns and controls more than 20% of the installed generation capacity located in, or capable of delivering electricity to, a power region shall file a market power mitigation plan with the commission not later than December 1, 2000. An electric utility or power generation company that the commission determines owns and controls more than 20% of the installed generation capacity located in, or capable of delivering electricity to, a power region after January 1, 2002 shall file a market power mitigation plan as directed by the commission. The commission may, for good cause, waive or modify the requirement to file a market power mitigation plan, in accordance with Public Utility Regulatory Act (PURA) §39.154(b). This section does not apply to an electric utility subject to PURA §39.102(c) until the end of the utility's rate freeze.

(b) **Initial information filing.** Each utility or power generation company that owns and controls, either separately or in combination with its affiliates, more than 10,000 megawatts (MW) of electric generation capacity located in a power region that is partly or entirely within the state shall file a calculation by September 5, 2000, detailing the installed generation for its power region expected as of January 1, 2002, and showing its percentage share of the installed generation capacity located in, or capable of delivering electricity to, the power region, plus the capacity expected to be interconnected to the transmission system by January 1, 2002, less the capacity to be auctioned off pursuant to PURA §39.153, and any grandfathered facilities capacity pursuant to PURA §39.154(e). The calculation shall be made pursuant to the requirements of §25.401 of this title (relating to Share of Installed Generation Capacity). The filing shall include detailed information that will allow the commission to replicate the calculation. At a minimum, the filing must include an itemized list of all generating units that are located in, or capable of delivering electricity to, the power region and are owned and controlled by the utility or power generation company and its affiliates in the power region or capable of delivering electricity to the power region. Generating units should be identified by name, capacity rating, ownership, location, and reliability council. Capacity shall be rated according to the method established in §25.91(f) of this title (relating to Generating Capacity Reports). The filing shall also include the transmission import capacity amounts that are to be included in the numerator and the denominator of the calculation prescribed by §25.401 of this title and an explanation of how the transmission capacity amounts were determined. Any interested parties may respond to the utility filings by filing comments with the commission by September 29, 2000. By October 20, 2000, the commission will indicate which utilities, if any, exceed the 20% threshold and are required to file a market power mitigation plan on or before December 1, 2000.

(c) **Market power mitigation plan.** A market power mitigation plan is a written proposal by an electric utility or a power generation company for reducing its ownership and control of installed generation capacity as required by PURA §39.154. A market power mitigation plan may provide for:

(1) the sale of generation assets to a nonaffiliated person;

(2) the exchange of generation assets with a nonaffiliated person located in a different power region;

(3) the auctioning of generation capacity entitlements as part of a capacity auction required by PURA §39.153;

(4) the sale of the right to capacity to a nonaffiliated person for at least four years; or

(5) any reasonable method of mitigation.

(d) **Filing requirements.** The plan shall include all supporting information necessary for the commission to fully understand and evaluate the plan. On a case-by-case basis, the commission may require the electric utility or power generation company to provide any additional information the commission finds necessary to evaluate the plan. The plan submitted should incorporate information addressing the determinations listed in subsection (f) of this section.

(e) **Procedure.** The commission shall approve, modify, or reject a plan within 180 days after the date of filing. The commission may not modify the plan to require divestiture by the electric utility or power generation company.

(f) **Commission determinations.** In reaching its determination under subsection (e) of this section, the commission shall consider:

(1) the degree to which the electric utility's or power generation company's stranded costs, if any, are minimized;

(2) whether on disposition of the generation assets the reasonable value is likely to be received;

(3) the effect of the plan on the electric utility's or power generation company's federal income taxes;

(4) the effect of the plan on current and potential competitors in the generation market;

(5) whether the plan provides adequate mitigation of market power; and

(6) whether the plan is consistent with the public interest.

(g) **Request to amend or repeal mitigation plan.** An electric utility or power generation company with an approved mitigation plan may request to amend or repeal its plan. On a showing of good cause, the commission may modify or repeal the mitigation plan.

(h) **Approval date.** If an electric utility's or power generation company's market power mitigation plan is not approved before January 1 of the year it is to take effect, the commission may order the electric utility or power generation company to auction generation capacity entitlements according to PURA §39.153, subject to commission approval, of any capacity exceeding the maximum allowable capacity prescribed by PURA §39.154 until the mitigation plan is approved. An auction held under this subsection shall be held not later than 60 days after the date the order is entered.

§25.91. Generating Capacity Reports.

(a) **Application.** This section applies to each person, power generation company, municipally owned utility, electric cooperative, and river authority that owns generation facilities and offers electricity for sale in this state. This section does not apply to an electric utility subject to Public Utility Regulatory Act (PURA) §39.102(c) until the end of the utility's rate freeze.

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

(1) **Nameplate rating** – The full-load continuous rating of a generator under specified conditions as designated by the manufacturer.

(2) **Summer net dependable capability** – The net capability of a generating unit in megawatts (MW) for daily planning and operational purposes during the summer peak season, as determined in accordance with requirements of the reliability council or independent organization in which the unit operates.

(c) **Filing requirements.** Reporting parties shall file reports of generation capacity with the commission by the last working day of February each year, based on the immediately preceding calendar year. Filings shall be made using a form prescribed by the commission.

(d) **Report attestation.** A report submitted pursuant to this section shall be attested to by an owner, partner, or officer of the reporting party under whose direction the report was prepared.

(e) **Confidentiality.** The reporting party may designate information that it considers to be confidential. Information designated as confidential will be treated in accordance with the standard protective order issued by the commission applicable to generating capacity reports.

(f) **Capacity ratings.** Generating unit capacity will be reported at the summer net dependable capability rating, except as follows:

(1) Renewable resource generating units that are not dispatchable will be reported at the actual capacity value during the most recent peak season, and the report will include data supporting the determination of the actual capacity value;

(2) Generating units that will be connected to a transmission or distribution system and operating within 12 months will be rated at the nameplate rating.

(g) **Reporting requirements**.

(1) Each reporting party shall provide the following information concerning its generation capacity (in MW) and sales (in megawatt-hours (MWh)) on a power region-wide basis and for that portion of a power region in the state:

(A) total capacity of generating facilities that are connected with a transmission or distribution system;

(B) total capacity of generating facilities used to generate electricity for consumption by the person owning or controlling the facility;

(C) total capacity of generating facilities that will be connected with a transmission or distribution system and operating within 12 months;

(D) total affiliate installed generation capacity;

(E) total amount of capacity available for sale to others;

(F) total amount of capacity under contract to others;

(G) total amount of capacity dedicated to its own use;

(H) total amount of capacity that has been subject to auction as approved by the commission;

(I) total amount of capacity that will be retired within 12 months;

(J) annual capacity sales to affiliated retail electric providers (REPs);

(K) annual wholesale energy sales;

(L) annual retail energy sales; and

(M) annual energy sales to affiliate REPs;

(2) Each reporting party shall provide the following information for each generating unit it owns in whole or in part:

(A) Name;

(B) Location by county, utility service area, power region, reliability council, and, if applicable, transmission zone;

(C) Capacity rating (MW) as specified in subsection (f) of this section;

(D) Annual generation (MWh);

(E) Type of fuel or nonfuel energy resource;

(F) Technology of natural gas generator; and

(G) Date of commercial operation.

(3) Each reporting party shall identify the name and capacity rating of each generating unit that it owns that is partly owned by other parties. For each such unit, it shall identify the other owners and their respective ownership percentages.

(4) Each reporting party shall identify the name and capacity rating of each generating unit that it owns but does not control. For each such unit, it shall identify the controlling party and briefly explain the nature of the other party's control of the unit.

(5) Each reporting party shall identify the name and capacity rating of each generating unit that it owns that is located on the boundary between two power regions and able to deliver electricity directly into either power region, and shall report the total sales from each such unit for the preceding year by power region.

(6) Each reporting party that is subject to the PURA §39.154(e) shall identify the name and capacity rating of each "grandfathered" generating unit that it owns in an ozone non-attainment area. Each reporting party shall also provide copies of any applications to

the Texas Natural Resources Conservation Commission (TNRCC) for a permit for the emission of air contaminants related to the grandfathered units, and it shall also provide a description of the progress it has made since its last Generating Capacity Report on achieving approval of each such TNRCC permit.

(7) Each reporting party shall identify the amount of transmission import capability that it has reserved and is available to import electricity during the summer peak into the power region from generating facilities that are owned by the reporting party or its affiliate in another power region.

(h) Upon written request by the person responsible for the commission's market oversight program, a reporting party shall provide within 15 days any information deemed necessary by that person to investigate a potential market power abuse as defined in PURA §39.157(a). In addition, the commission may request reporting parties to provide any information deemed necessary by the commission to assess market power or the development of a competitive retail market in the state, pursuant to §39.155(a). A reporting party may designate information provided to the commission as confidential in accordance with subsection (e) of this section.

§25.401. Share of Installed Generation Capacity.

(a) **Application.** The provisions of this section apply to power generation companies.

(b) **Share of installed generation capacity.** The percentage share of installed generation capacity for a power generation company will be determined by dividing the installed generation capacity owned and controlled by the power generation company in, or capable of delivering electricity to, a power region by the total installed generation capacity located in, or capable of delivering electricity to, the power region.

(c) **Capacity ratings.** For purposes of this section, generating unit capacity ratings shall be consistent with §25.91(f) of this title (relating to Generating Capacity Reports). The commission may revise reported capacity ratings if they are found to be incorrect.

(d) **Installed generation capacity of a power generation company.**

(1) In determining the percentage shares of installed generation capacity under the PURA §39.154, the commission shall combine capacity owned and controlled by a power generation company and any entity that is affiliated with that power generation company within the power region, reduced by the installed generation capacity of those facilities that are made subject to capacity auctions under PURA §39.153(a) and (d).

(2) In determining the percentage shares of installed generation capacity, the commission shall increase the installed generation capacity owned and controlled by a power generation company by the transmission import capability that is available for importing electricity during the summer peak season into the power region from generating facilities that are owned by the power generation company or an affiliate in another power region.

(3) In determining the percentage shares of installed generation capacity owned and controlled by a power generation company under PURA §39.154 and §39.156, the commission shall, for purposes of calculating the numerator, reduce the installed generation capacity owned and controlled by that power generation company by the installed generation capacity of any "grandfathered facility" within an ozone nonattainment area as of September 1, 1999, for which that power generation company has commenced complying or made a binding commitment to comply with PURA §39.264. This paragraph applies only to a power generation company that is affiliated with an electric utility that owned and controlled more than 27% of the installed generation capacity in the power region on January 1, 1999. The commission will consider a permit application to the Texas Natural Resource Conservation Commission (TNRCC) to be adequate evidence that the power generation company has commenced complying or made a binding commitment to comply with PURA §39.264. However, the commission will review the progress that has been made on achieving an

approved an TNRCC permit, when it reviews and updates market share percentages, and if adequate progress has not been made, the commission may choose to include the grandfathered capacity in the numerator.

(e) **Total installed generation.** The total installed generation will consist of the installed generation capacity that is located in, or capable of delivering electricity to, a power region.

(1) Installed generation capacity will include all potentially marketable electric generation capacity. Except as provided in paragraph (2) of this subsection, installed generation capacity will include:

(A) generating facilities that are connected with a transmission or distribution system;

(B) generating facilities used to generate electricity for consumption by the person owning or controlling the facility;

(C) generating facilities that will be connected with a transmission or distribution system and operating within 12 months; and

(D) generating facilities that are located on the boundary between two power regions and are able to deliver electricity directly into either power region, except that the capacity of such facility shall be allocated between the power regions based on the share of its total electric energy that the facility sold in each power region during the preceding year.

(2) Installed generation capacity will not include generating facilities that have a nameplate rating equal to or less than 1 megawatt (MW).

(3) The amount of installed generation capacity that is capable of delivering electricity to a power region will be determined by:

(A) the import transmission capacity during the summer peak period of the alternating current transmission interconnections between the power region at issue and other power regions; and

(B) the import capacity during the summer peak period of the reliable direct current interconnections between the power region at issue and other power regions.

This agency hereby certifies that the rules, as adopted, have been reviewed by legal counsel and found to be a valid exercise of the agency's legal authority. It is therefore ordered by the Public Utility Commission of Texas that §25.90 relating to Market Power Mitigation Plans, §25.91 relating to Generating Capacity Reports, and §25.401 relating to Share of Installed Generation Capacity are hereby adopted with changes to the text as proposed.

ISSUED IN AUSTIN, TEXAS ON THE 11th DAY OF AUGUST 2000.

PUBLIC UTILITY COMMISSION OF TEXAS

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Chairman Pat Wood III

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Commissioner Judy Walsh

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Commissioner Brett A. Perlman