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ELECTRIC

MEMORANDUM DECISIONS

Public Utility Commission of Texas

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PETITION OF LOWER COLORADO RIVER AUTHORITY ET AL. FOR DETERMINATION OF WHEELING IMPACT OF THE TRANSMISSION OF BULK POWER FROM OKLAUNION UNIT NO. 1 TO THE PUBLIC UTILITIES BOARD OF THE CITY OF BROWNSVILLE	§ § § § § §	**DOCKET NO. 6995**

December 12, 1988

Initial and Supplemental Examiner's Reports adopted. LCRA found to be entitled to compensation from Public Utilities Board of City of Brownsville from wheeling of remotely generated power from Oklaunion Unit No. 1 to Brownsville.

[1] RATEMAKING--RATE DESIGN--ELECTRIC--SPECIAL TARIFFS AND RIDERS--WHEELING RATES
MISCELLANEOUS--ELECTRIC

LCRA entitled to compensation for impacts on its transmission system caused by the wheeling of remotely generated power from Oklaunion Unit No. 1 to Brownsville. (p.1503)

[2] RATEMAKING--RATE DESIGN--ELECTRIC--SPECIAL TARIFFS AND RIDERS--WHEELING RATES

Vector-absolute megawatt miles are the appropriate units of measurement of impacts on LCRA transmission system caused by the wheeling of remotely generated power from Oklaunion Unit No. 1 to Brownsville. (p.1511)

[3] RATEMAKING--RATE DESIGN--ELECTRIC--SPECIAL TARIFFS AND RIDERS--WHEELING RATES

Commisssion approved LCRA wheeling tariff applicable specifically to the Public Utilities Board of the City of Brownsville's wheeling of remotely generated power from Oklaunion Unit No. 1. (p.1564)

[4] RATEMAKING--RATE DESIGN--ELECTRIC--SPECIAL TARIFFS AND RIDERS--WHEELING RATES
MISCELLANEOUS--ELECTRIC

Commission staff directed to review P.U.C. SUBST. R. 23.67 to consider inclusion of remote generation within the ambit of the rule, in furtherance of a uniform statewide policy with respect to the wheeling of power from remotely sited generation facilities. (p. 1564)

DOCKET NO. 6995

PETITION OF LOWER COLORADO RIVER AUTHORITY ET AL. FOR DETERMINATION OF WHEELING IMPACT OF THE TRANSMISSION OF BULK POWER FROM OKLAUNION UNIT NO. 1 TO THE PUBLIC UTILITIES BOARD OF THE CITY OF BROWNSVILLE	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Procedural History

This docket was initiated on August 19, 1986, by final Order of the Commission in Docket No. 6890, styled Application of Central Power and Light Company and the Public Utilities Board of the City of Brownsville for Approval of the Sale and Purchase of an Interest in Oklaunion Unit No. 1, ____ P.U.C. BULL. ____ (August 19, 1986). In evaluating the merits of the proposed sale of a 10.16 percent interest in Oklaunion Unit No. 1 by Central Power and Light Company (CP&L) to the Public Utilities Board of the City of Brownsville (PUB), the Commission severed and excluded from consideration in that docket certain issues raised by the Lower Colorado River Authority (LCRA) and other intervenors concerning the adequacy of PUB's arrangements for wheeling power from Oklaunion Unit No. 1 to PUB's certificated service area. The final Order in Docket No. 6890 approved the proposed sale, but required the initiation of the instant proceedings to address unresolved wheeling issues arising from the transaction.

The initial prehearing conference in this docket was convened on September 9, 1986, at which time appearances were made by Mr. John Davidson on behalf of PUB, Mr. Milton Lorenz on behalf of CP&L, Mr. Lawrence Smith on behalf of LCRA, Mr. Walter Washington on behalf of the Office of Public Utility Counsel (OPC) and Mr. Frank Davis on behalf of the Commission staff. PUB, LCRA, CP&L and OPC were found to be parties as a matter of right by virtue of their participation in Docket No. 6890, and were not required to formally move for intervention. PUB was directed to mail individual notice of the proceeding to all utilities within the Electric Reliability Council of Texas (ERCOT) posessing generation and/or transmission facilities, and to publish notice of the pendency of the proceeding in the Texas Register. Further, the examiner implemented a discovery schedule and established an October 16, 1986, intervention deadline for utilities claiming a right to compensation for the wheeling of PUB entitlements from Oklaunion to Brownsville.

On September 19, 1986, PUB filed a sworn affidavit attesting to the issuance of individual notice of the proceeding to ERCOT utilities. However, as PUB was unable to secure publication of notice in the Texas Register, the September 9, 1987, publication order was rescinded by examiner's order dated September 22, 1986. Notice of the pendency of this proceeding was subsequently published as a Commission-promulgated notice in the October 3, 1986, issue of the Texas Register.

Motions to intervene were filed by the following entities prior to the expiration of the October 16, 1986, deadline established by the examiner:

Tex-La Electric Cooperative of Texas, Inc (Tex-La)
Rayburn County Electric Cooperative, Inc. (RCEC)
Association of Wholesale Customers (AWC)
West Texas Utilities (WTU)
Brazos Electric Power Cooperative, Inc. (BEPC)
South Texas Electric Cooperative (STEC)
Texas Cooperative Group (TCG)
Texas-New Mexico Power Company (TNP)
Texas Municipal Power Agency (TMPA)
Texas Utilities Electric Company (TUEC)
Golden Spread Electric Cooperative (GSEC)
Houston Lighting & Power Company (HL&P)
City of Austin (COA)

A second prehearing conference was conducted in this docket on October 20, 1986, at which time appearances were made by the following:

Party	Representative
WTU, CP&L	Milton Lorenz
STEC, TCG and RCEC	Campbell McGinnis
BEPC	Bill Townsend
AWC	Tom Anson
Tex-La	Richard Balough
PUB	John Davidson
LCRA	Lawrence Smith
TUEC	Dan Bohannan
OPC	Walter Washington
TNP	Patricia Bowers
TMPA	Jim Bailey
COA	Robert Kahn
HL&P	Robert Howell
Commission staff	Frank Davis

By oral ruling at the prehearing conference, subsequently memorialized by written order dated October 21, 1986, the scope of the docket was limited to the issues of whether utilities which had not entered into transmission agreements with PUB but which allege that their transmission systems are affected by the wheeling of power from Oklaunion to Brownsville are in fact affected by that transaction and, if so, determination of an appropriate methodology for calculating the level of compensation to be paid to such utilities by PUB. Because this docket was not intended by the Commission as a vehicle for crafting new wheeling policies of statewide application, the parties were advised that the examiner would recommend at the conclusion of the proceeding that no precedential value attach to the methodology adopted in this docket, that the Commission initiate a rulemaking proceeding to address the issue of an appropriate methodology for calculating impact charges for wheeling remotely generated power in instances where impacted utilities and the generating utility cannot reach agreement on appropriate rates, and that whatever methodology is adopted in this docket be treated as an interim methodology to be superseded by the requirements of any remote generation rule subsequently adopted by the Commission. Based upon the limited scope of the proceeding, all motions to intervene were denied with the exception of those filed by the following entities, who alleged the existence of a direct impact from the wheeling of PUB's Oklaunion entitlements: BEPC, STEC, TCG, TUEC, HL&P and COA. A procedural schedule was established at the prehearing conference and the hearing on the merits was scheduled to commence on April 20, 1987.

On October 28, 1986, the Commission received a late-filed motion to intervene from Medina Electric Cooperative, Inc., (MEC) in which the cooperative alleged that its transmission system was directly impacted by the wheeling of PUB entitlements. Although the motion was opposed by PUB, the request for intervention was granted by examiner's order dated November 19, 1986.

By order dated November 5, 1986, the examiner directed those parties who had reached transmission agreements with PUB, and therefore had no basis for continued participation in the docket, to withdraw from the docket. Motions to withdraw were received from the following parties and granted, with the understanding that withdrawal would not prejudice a subsequent request to intervene in the event the scope of the docket was expanded beyond that delineated in the examiner's October 21, 1986, order:

Party	Date Filed	Date Granted
HL&P	November 12, 1986	November 19, 1986
CP&L	November 13, 1986	November 19, 1986
TUEC	November 19, 1986	November 24, 1986
OPC	December 5, 1986	December 11, 1986
TCG	December 22, 1986	January 16, 1987
BEPC	January 13, 1987	January 16, 1987
COA	January 20, 1987	January 22, 1987

On February 10, 1987, Texas Industrial Energy Consumers (TIEC) filed a motion to intervene, which was denied by order dated March 4, 1987, on the basis that the status of TIEC's members as cogenerators or prospective cogenerators was irrelevant since the docket did not pertain to wheeling charges assessed against cogenerators, and on the further basis that none of the member clients which TIEC claimed to be representing were in fact customers of any of the parties to the docket.

On March 26, 1987, PUB filed a motion requesting permission to file supplemental direct testimony due to MEC's failure to serve PUB and LCRA with copies of its prefiled direct testimony until after PUB's deadline for filing responsive testimony had passed. PUB's motion was granted by examiner's order dated March 27, 1987.

On March 30, 1987, LCRA filed a motion requesting permission to file rebuttal testimony. PUB filed a response in opposition to the motion on April 1, 1987. As LCRA was assigned the burden of proof in this proceeding, LCRA's motion was granted by examiner's order dated April 6, 1987.

On April 15, 1987, the Commission's general counsel filed a motion for postponement of the hearing and the deadline for filing staff testimony, based upon the staff's need for additional time to prepare its case. The motion was not opposed by any party to the case, and in recognition of the importance of a well reasoned staff position in this matter, the examiner granted an indefinite continuance by order dated April 16, 1987, and directed the parties to negotiate an agreed date for the commencement of the hearing.

By letter dated April 22, 1987, general counsel indicated that the parties were in agreement on a revised hearing date, and by examiner's order dated May 1, 1987, the hearing was rescheduled to an agreed date of July 7, 1987.

The hearing on the merits was convened on July 7, 1987, with the undersigned examiner presiding. Present were Mr. Lawrence Smith on behalf of LCRA, Mr. John Davidson, Mr. Robert McDiarmid and Mr. Ruben Barrera on behalf of PUB, Mr. Allen King on behalf of MEC, Mr. Thomas Anson on behalf of AWC and Mr. Frank Davis on behalf of the Commission staff. The hearing continued day to day until July 10, 1987 at which time the hearing was recessed until July 20, 1987. The hearing was reconvened and concluded on July 20, 1987.

Following the conclusion of the hearing the examiner established filing deadlines of August 28, 1987, for the submission of initial briefs and September 11, 1987, for reply briefs. Due to delays in obtaining transcripts of the hearing, PUB requested an extension of the deadline for filing initial and reply briefs until September 4, 1987, and September 18, 1987, respectively. PUB's motion was granted without opposition by examiner's order dated August 21, 1987.

The Commission has jurisdiction over the matters raised in this proceeding pursuant to Sections 16(a) and 17(e) of the Public Utility Regulatory Act (PURA or the Act), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987).

II. Introduction

Oklaunion Unit No. 1 is located in Wilbarger County near the Texas/Oklahoma border. PUB's service territory is located more than 600 miles away in the southern-most tip of Texas. TUEC, HL&P, LCRA, COA and City Public Service Board of San Antonio intervened in Docket No. 6890 because, although PUB was proposing to purchase an interest in a generating unit more remotely located in relation to PUB's service territory than any other generating unit in ERCOT, PUB had made no attempt to enter into wheeling arrangements with those entities, notwithstanding the fact that their transmission systems lay, in whole or in part, between those two points, and the existence of those facilities was essential to PUB's plan to use generation from Oklaunion to serve load in Brownsville.

PUB subsequently proceeded to secure wheeling contracts with each of the utility intervenors in Docket No. 6890 with the exception of LCRA, with whom PUB could not reach agreement. Although MEC, which did not participate in Docket No. 6890, subsequently intervened in this docket claiming a right to compensation from PUB, this docket is fundamentally a dispute between LCRA and PUB over the level of wheeling charges, if any, owed to LCRA by PUB.

LCRA and PUB agree that the Commission's current wheeling rules, P.U.C. SUBST. R. 23.66 and 23.67, do not apply to the wheeling of remote generation. P.U.C. SUBST. R. 23.66 applies solely to the wheeling of power from qualifying cogeneration facilities to other electric utilities. P.U.C. SUBST. R. 23.67, which applies to wheeling services incident to a purchase and sale of firm power between electric public utilities and/or municipally-owned electric utilities does not speak to the situation where a utility is wheeling its own generation from a remotely sited generating unit to its own service territory. Further, wheeling pursuant to P.U.C. SUBST. R. 23.67 is on an as-available basis only, permitting the denial of wheeling services for capacity-related reasons. Remote generation is thus incompatible with this requirement to the extent that it constitutes base load power which must be wheeled on a firm basis over the life of the plant.

In the absence of a Commission - promulgated rule addressing the wheeling of firm power from remotely sited generating units, the selection in this docket of a wheeling methodology applicable to that circumstance is necessary in order to resolve the specific issues in dispute. However, as different wheeling methodologies can produce very different results, and those results can have profound implications within the industry, Commission acceptance of a particular methodology for use in a given circumstance is first and foremost a question of policy to be decided through a rulemaking proceeding. In initiating this docket, the Commission sought to create a forum to resolve very specific disputes severed from consideration in Docket No. 6890. The Commission did not mandate, nor did it in the examiner's opinion expect, the use of this proceeding as a forum for the development of policy with respect to the wheeling of remote generation. It would be wholly inappropriate to impute that purpose to this docket given the lack of industry-wide participation in the proceeding. Therefore, in this report, the examiner has consciously striven to minimize the potential precedential value which may be assigned this docket in future proceedings. The examiner has attempted to avoid radical departures from traditional Commission approaches to wheeling issues, to the extent permitted by the record.

Regardless of whether the Commission chooses to accept or reject the examiner's proposed resolution of the issues presented, the examiner strongly recommends that the Commission initiate a rulemaking proceeding upon conclusion of this docket for the purpose of formulating a uniform statewide policy with respect to the wheeling of power from remotely sited generation facilities. As remote generation continues to increase in prevalence, the wheeling issues relevant to remote generation will continue to grow in importance. Implementation of a coherent statewide policy will insure that economic responsibility for transmission facilities necessary to support remote generation will be allocated among the owners of remote generation and the owners of transmission facilities in a manner equitable to both. This, in turn, will insure the long term viability of remote generation as well as the continued existence of adequate transmission facilities to support that generation.

At such time as the Commission implements a wheeling rule applicable to remote generation, the examiner urges that the wheeling rates established in this docket, if any, be superseded on a prospective basis by revised rates calculated in accordance with the wheeling methodology incorporated in that substantive rule.

III. Opinion

A. Existence of Impact

The final Order in Docket No. 6890 specified the style of this case, included in which is the phrase "determination of wheeling impact". A threshold issue has been raised in this docket concerning the intended meaning of that phrase, LCRA taking the position that "wheeling impact" is synonymous with "use" and PUB asserting that "wheeling impact" is synonymous with a demonstrable change in power flows on transmission lines with which there must be associated some adverse effect. The examiner believes that PUB has placed far too much reliance in its arguments upon the specific phraseology employed in the style of this case. The style of the docket, as set forth in the final Order in Docket No. 6890 (which the undersigned examiner drafted), was not intended to convey any special meaning separate and apart from the Commission's intent that this docket serve as a forum in which the claims of right to compensation urged by LCRA and others, as well as the appropriate levels of compensation, if any, could be litigated. The style of the case was not intended to dictate the theory of recovery which must be argued. As the party with the burden of proof, LCRA is entitled to choose and advocate the theory under which it believes it is entitled to compensation from PUB, and such must control over the verbiage utilized in the label appended by the Commission to this docket. As this docket is intended to test the validity of LCRA's claim of right to compensation, and that claim is based upon use of its transmission facilities rather than upon the occurence of a demonstrable adverse change in power flows on those facilities, the term "wheeling impact" must be construed as being synonymous with "use". The examiner accordingly finds that, to the extent that it can be shown that use of Oklaunion generation to meet Brownsville load involves the use of a particular utility's transmission facilities, an impact exists within the intended meaning of the final Order in Docket No. 6890.

Having defined the term "wheeling impact", the issue of whether the LCRA and MEC transmission systems are in fact impacted must be addressed. It is clear from the record in this docket that the flow of power within an integrated transmission grid is a function of the existence and location of the loads and generation sources connected to the grid. It is undisputed that the existence and location of Oklaunion Unit No. 1 causes changes in transmission line loadings on the lines owned by LCRA and MEC as well as upon lines owned by the other ERCOT utilities. However, it is also undisputed that the transfer of an ownership interest in Oklaunion from CP&L to PUB causes no change in the power flows on any of the transmission lines within the ERCOT integrated transmission grid since ownership has no effect on power flows, except to the extent that ownership permits one to control the generation level of a unit, and in this instance, the record reflects that PUB's ownership interest in Oklaunion does not entitle it to control the economic dispatch of that unit.

PUB witness Riley Rhorer testified that the siting of the Oklaunion plant was beneficial to the entirety of ERCOT because it served to reduce the level of south to north drift on the ERCOT transmission grid caused by the preponderance of power plants located in the southeastern portion of the state. Given the beneficial location of the plant to ERCOT as a whole, the fact that neither LCRA nor MEC opposed the issuance of a CCN for Oklaunion based upon the effect it would have on their transmission systems, and the fact that PUB's subsequent acquisition of an interest in the plant for the purpose of meeting its load requirements has not changed in any respect the physical flow of power on the MEC and LCRA transmission lines, PUB argues that there is no impact upon the LCRA and MEC transmission systems as a consequence of the use of Oklaunion generation to serve PUB's load.

PUB's argument is at first glance highly persuasive. However, as discussed previously, the real question is whether the use of Oklaunion generation to meet Brownsville load involves the use of the LCRA and MEC transmission facilities. PUB's argument sidesteps the obvious fact that, in order to satisfy Brownsville's load requirements from a generation source located 600 miles away, there must first exist transmission facilities connecting the generation source and the load area. PUB owns only 41.9 miles of transmission line out of a total of 30,600 miles of line comprising the integrated ERCOT transmission grid, and PUB's lines are all located within the immediate proximity of Brownsville. As PUB does not own any transmission facilities connecting Oklaunion to the PUB load area, PUB must rely upon the transmission facilities of the other ERCOT utilities in order to enable it to meet its load requirements with power generated by the Oklaunion facility.

As noted by LCRA witness Walter Reid, the laws of physics dictate that power flow will distribute ubiquitously throughout an integrated transmission system. Thus, use of Oklaunion generation to serve load in Brownsville necessarily involves the use of the individual transmission systems comprising the interconnected ERCOT grid, including the facilities owned by LCRA and MEC.

Based upon the foregoing, the examiner finds that the use of Oklaunion generation to serve PUB's load impacts the LCRA and MEC transmission systems.

B. Right to Compensation

LCRA's argument in support of its right to compensation for the use made of its transmission facilities by PUB is simple and direct. LCRA asserts that public utilities have a statutory and common law duty to provide utility service to all those who require it, and they have a reciprocal right to insist upon the payment of just and reasonable rates, lawfully established, for the use of those services. As the use of Oklaunion generation necessarily involves the use of LCRA's transmission facilities, LCRA asserts that it is providing a service to PUB for which it is entitled to compensation.

PUB acknowledges this Commission's jurisdiction to require the payment of wheeling charges to LCRA and MEC by PUB as a consequence of PUB's use of Oklaunion generation to meet its Brownsville load. However, it asserts a number of arguments in support of the proposition that no compensation is owed. A discussion of each of these arguments follows.

First, PUB asserts that there exists no obligation to pay compensation since it has never requested or contracted for transmission services from LCRA or MEC. The examiner finds this argument to be particulary unpersuasive. The right to compensation appropriately arises from use rather than from the presence or absence of a contract specifying the level of agreed compensation for that use. PUB's rationale, if accepted, would result in the ability to avoid liability for use merely by refusing to pay for the use made of facilities. This position is clearly without merit.

Second, PUB asserts that use of one's transmission facilities by others is an unavoidable result of the owner's voluntary decision to interconnect with an integrated generation and transmission grid, and that the benefits which flow to the owner as a consequence of interconnection more than offset that result. In the examiner's view, the fact that inadvertent flows on transmission facilities necessarily occur as a consequence of interconnection does not absolve PUB from responsibility for wheeling charges. PUB's argument is far more persuasive when restated as follows. PUB has voluntarily availed itself of one of the substantial benefits which flow from an integrated generation and transmission grid, to wit: the ability to engage in remote generation without the need to construct transmission facilities connecting the generation to the load area, creating a reciprocal obligation to bear in part the costs of the substantial transmission facilities needed to support that integrated grid. The argument that PUB need not bear any responsibility for the costs of transmission facilities used to support its remote generation, merely because the owners of the transmission facilities benefit by interconnection, is wholly without merit and should be rejected.

Third, PUB argues that the assessment of wheeling charges against remote generators would be unreasonably discriminatory given that non-remote generation causes the same types of impacts upon transmission facilities within an integrated grid as does remote generation, yet charges are not assessed for the inadvertent flows caused by non-remote generation. The record reflects that PUB is correct in its assertion that non-remote generation can and does affect power flows on the transmission lines of other utilities. That phenomenon is referred to within ERCOT as "inadvertent flow" because those flows are an inadvertent consequence of interconnection. However, PUB's discrimination argument is in the examiner's opinion without merit. It is clear that under Texas case law, the dividing line between permissible and impermissible discrimination by a public utility is generally that drawn by the "rule of reasonableness" and that mere inequality is not itself unlawful discrimination. Under this standard, unequal treatment is permissible so long as there exists a substantial and reasonable ground of distinction between the favored and disfavored individuals or classes. A substantial and imminently reasonable ground of distinction exists in this instance. Specifically, the owners of non-remote generation are capable of independently serving their native system load from a native generation source without reliance upon the transmission facilities of others, whereas, absent the construction of a transmission facility by the owner of a remote generator to connect its source of generation to its native system load, the owner of remote generation is dependent upon the existence of the transmission facilities of other ERCOT members in order to meet its load requirements with that remote generation source. The fact that PUB must rely upon the transmission investment of other utilities in order to serve its load with Oklaunion generation is in the examiner's opinion a substantial distinction which supports a different treatment for PUB than that accorded the owners of non-remote generation.

A fourth argument put forward by PUB is that compensation is inappropriate absent a showing that use of the transmission facilities will adversely affect system reliability of interchange capability. The record in this docket does not support a finding that the operation of Oklaunion or its use to meet PUB's load requirements will affect the reliability or interchange ability of the LCRA and MEC transmission systems, nor has either utility made that assertion. However, the record also reflects that transmission facilities within ERCOT are planned and built with sufficient capacity and line redundancy to assure the ability of those facilities to handle the loads placed upon them under multiple contingencies. The entire transmission planning process is geared toward insuring that impairments in system reliability or interchange ability will not occur. To the extent that a reliability problem develops, LCRA witness Reid testified that the cause and effect relationship is almost impossible to determine. Thus, the examiner finds it wholly unrealistic to premise the payment of compensation for the use of transmission facilities upon satisfaction of the test suggested by PUB. It appears that PUB's reference to system reliability or interchange capability is drawn from the following language contained in the May, 1986 version of the ERCOT Operating Guides (PUB Exhibit No. 2).

II. TRANSMISSION ASSOCIATED WITH REMOTE GENERATING CAPACITY

A. Transmission Facilities - Providing for associated transmission facilities used to transmit the power from remote generating capacity shall be the responsibility of the "owner of the remote generating capacity" (hereinafter called "owner") and accomplished by A. 1. or A.2. below, or a combination thereof.

1. Construction of Additional Transmission Facilities - The owner will provide for all required transmission facilities to avoid adversely affecting the interchange capability or reliability of other systems.

2. Transmission Service - If the owner desires to use or rely upon the transmission capacity of another system or systems, it will be his responsibility to make contractual arrangements for the use or availability of such.

(Id. at page A-34).

PUB implied at the hearing that if the construction of additional facilities was not necessary to avoid adversely affecting the interchange capability or reliability of other systems, then the requirements of subparagraph 1 above were satisfied and PUB therefore had no transmission obligations with respect to its ownership interest in Oklaunion. The ERCOT Operating Guides, constituting ERCOT's mutually agreed upon practices to be followed in operating the interconnected ERCOT system, are not by any means binding on this Commission. However, to the extent that one wishes to place some reliance upon them, it appears to the examiner that subparagraph 1 is intended to create the obligation to construct additional facilities where required to avoid impairment of interchange capability or reliability, but that in any event subparagraph 2 creates the obligation to contract for the use of transmission facilities where the owner of the remote generation is relying upon the transmission capacity of existing facilities owned by other ERCOT members. Thus, to the extent that PUB's argument relies on the provisions of the ERCOT Operating Guides, those guides in fact fully support the right to compensation claimed by LCRA and MEC.

A fifth argument put forward by PUB is its assertion that Texas range law, water law, lateral support law, law pertaining to improvements of easements, as well as the "Texas party wall" doctrine provide analogous authority drawn from private civil litigation for PUB's position that it has no obligation to compensate other utilities for the use of their transmission facilities occassioned by PUB's reliance upon Oklaunion to serve its Brownsville load.

The examiner finds the analogies drawn by PUB between the instant case and that body of caselaw to be substantially flawed. Furthermore, since the caselaw cited by PUB has no applicability in the utility context, the examiner has foregone a detailed discussion of the difficulties with the analogies drawn by PUB. In the examiner's view, the bottom line in this proceeding, as noted by counsel for LCRA, is that public utilities have a statutory and common law duty to provide utility service to all those who require it, and they have a reciprocal right to insist upon the payment of just and reasonable rates, lawfully established, for the use of those services.

The examiner must observe that there is a substantial equity argument which weighs against PUB's assertion that LCRA and MEC are not entitled to compensation for the use made of their transmission systems by PUB. Prior to purchasing an interest in Oklaunion, PUB relied principally upon firm power purchases from CP&L to meet its base load requirements. Within the price paid for that power by PUB was included not only CP&L's generation costs but transmission costs incurred by CP&L to support that generation. The acquisition of an ownership interest in Oklaunion enabled PUB to replace its power purchases from CP&L with power generated by the Oklaunion plant. The decision to acquire an ownership interest in Oklaunion was motivated in part by the favorable economics of that plant. However, if PUB's power costs are to be determined by the capital costs and operating costs of that plant, PUB's power costs should include responsibility for the transmission facilities which must be used to support PUB's load requirements from that generating plant. LCRA, MEC and other ERCOT utilities have incurred substantial costs to construct transmission facilities necessary to support power flows throughout the ERCOT system. As those facilities are necessarily used by PUB to serve PUB's load from generation in North Texas, the payment of compensation to the owners of those facilities is necessary to avoid the subsidization by other utility ratepayers of the true costs of serving PUB's load.

A sixth and final argument put forward by PUB is that, as it has reached wheeling agreements with other ERCOT utilities, there is no need to contract with LCRA or MEC for wheeling services. The examiner finds this argument untenable based upon the record in this docket. The record reflects that, because of the nature of power flows on an integrated transmission system, LCRA and MEC transmission facilities are used by PUB to serve PUB's load requirements with Oklaunion generation. Compensation should appropriately be paid to all of those affected rather than to only certain arbitrarily designated entities. PUB's argument constitutes in essence the advocacy of a "contract path" methodology which is singularly inappropriate given the fact that not one witness in this proceeding supported the use of a contract path methodology. To the extent that PUB wishes to rely upon the fact that it has paid compensation to other utilities, the examiner would make two observations. First, that fact tends to support the existence of an obligation to pay compensation for the use of the transmission facilities owned by other ERCOT utilities. Second, the compensation paid to other ERCOT utilities was calculated pursuant to the megawatt mile methodology embodied in P.U.C. SUBST. R. 23.67, and that methodology assumes that all ERCOT entities with demonstrable megawatt mile impacts are entitled to compensation. The record reflects that both LCRA and MEC possess demonstrable impacts pursuant to that methodology.

[1] Based upon the foregoing discussion, the examiner finds that LCRA and MEC are entitled to compensation from PUB for the use made of their transmission facilities as a consequence of PUB's use of Oklaunion generation to meet its load requirements.

C. Selection of Wheeling Methodology

Having established that meeting Brownsville's load requirements with Oklaunion generation necessitates the use by PUB of LCRA's and MEC's transmission facilities, and having further established that LCRA and MEC are entitled to compensation for that use, quantification of the level of use of those facilities is a prerequisite to the determination of the amount of compensation owed by PUB. This in turn requires specification of the wheeling methodlogy upon which the transaction is to be premised, since the methodology determines the appropriate unit of measurement. It should be noted that the wheeling methodology selected for application to this transaction will have an enormous impact upon the level of compensation due LCRA and MEC. There are a number of different methodologies which could be used to model this transaction. However, only three have been proposed by the parties: the boundary flow method, the megawatt mile method, and what has been referred to in this proceeding as the "postage stamp" method. A discussion of each follows.

1. Boundary Flow Method

Although MEC has proposed the "tie-line change" boundary flow methodology for use in quantifying the extent of PUB's use of its transmission facilities, MEC's sole witness, Mr. Thomas Foreman, did not provide an explanation of the mechanics of that methodology in his prefiled testimony, nor did he provide any extensive elaboration on cross-examination. Therefore, the examiner must rely upon the descriptions of the methodology provided by LCRA witness Walter Reid and PUB witness Riley Rhorer.

According to Mr. Reid, the boundary flow method of assessing transmission system use attempts to measure the change in power flow on utility-to-utility tie lines which result from a power transfer. The changes in individual tie-line flows are combined to yield the total amount of power which is purported to flow through the utility's transmission system as a consequence of a particular wheeling transaction. Under this methodology, the unit of measurement is the megawatt. The changes in line flows on utility-to-utility tie lines at the boundaries of the affected utility are determined through the use of base and change computer models designed to simulate the flow of power on transmission lines given both the presence and absence of the wheeling transaction.

LCRA and PUB both oppose the use of the boundary flow method to quantify transmission system usage. According to LCRA witness Reid, the methodology does possess some strengths, in that it makes an attempt to measure usage objectively, it uses familiar concepts, it uses the same billing units as used to allocate costs to retail customers, and it provides predictable and repeatable results. However, Mr. Reid and Mr. Rhorer both believe that the weaknesses inherent in the methodology preclude its use.

There are four fundamental criticisms of the methodology which Mr. Reid and Mr. Rhorer appear to share. First, megawatts constitute meaningless units of measurement within a wheeling context because megawatt flows on tie-lines at a utility's boundary do not measure the extent of usage of the lines within the utility's system. Second, the methodology makes the incorrect assumption that all utilities are the same size and that all lines are used equally to transmit power. Third, the large number of interconnections in ERCOT can cause the same megawatts to computationally enter, exit and re-enter the same system several times at its boundaries, thus overstating the amount of power that is computed to flow through a given system. Fourth, the methodology suffers from "pancaking", whereby the level of compensation owed is a function of the number of discrete entities located between the generation source and the load area. For instance, if the level of use of a transmission system were determined to be 100 MW and the system were subsequently split into two systems, then the usage of those transmission facilities would double from 100 MW to 200 MW as a consequence of the split, even though there had been no change in the amount of power wheeled or the amount of facilities used.

In addition to these criticisms, PUB witness Rhorer asserts that the boundary flow methodology is fatally flawed as a consequence of its reliance upon base and change computer simulations to model transmission line flows given the presence or absence of specific wheeling transactions. As reliance upon base and change computer simulations is common to both the boundary flow and megawatt mile methodologies, Mr. Rhorer's criticisms of those simulations are addressed in the section of this report discussing the megawatt mile methodology.

2. Megawatt Mile Method

Both LCRA and the Commission staff advocate the use of variants of the megawatt mile method to measure transmission system usage. The megawatt mile method, as with the boundary flow method, is premised upon the use of base and change computer simulations to contrast the flow of power on transmission lines given the alternate presence and absence of a particular wheeling transaction. The methodology eliminates the previously discussed weaknesses associated with the boundary line method as a consequence of the addition of distance as a component element of the megawatt unit of measurement. Under this method, the change in megawatt flow attributable to a specific wheeling transaction is measured on each of the individual transmission lines which comprise the transmission system. The change in megawatt flow on each line is then multiplied by the length, in miles, of the line, producing a measurement of usage of the line expressed in megawatt miles. The megawatt mile impacts on each line can then be summed to produce a measurement of total usage of the transmission system occasioned by a particular transaction.

PUB has raised only one fundamental criticism regarding the use of the megawatt mile method to measure transmission system usage, and that criticism is equally applicable to the boundary flow method. PUB argues that the use of base and change computer simulations, especially generator-to-load simulations, to model the changes in transmission line flows attributable to a specific wheeling transaction is unsupportable. According to PUB witness Rhorer, the base and change computer simulations utilized by LCRA do not model the changes in flow which actually occur as a consequence of a given wheeling transaction. Rather, they model hypothetical changes in flow which would occur were one to assume that the power being wheeled in fact physically flows from the designated source of generation to the designated load area. As conceded by all witnesses who addressed the subject, one cannot determine which load is being served from a particular generating unit connected to an integrated transmission system, because power flows to the loads closest to it as defined by the location and size of the other generation sources and loads tied to the grid. By modeling load flows assuming the existence of designated generation and designated load and then re-running the model assuming the non-existence of both the source of generation and the load in question, as is done under the megawatt mile and boundary flow methods, power is assumed by the simulations to flow from the designated source of generation to the designated load, and the theoretical changes in flow which result accordingly bear no relationship to the changes in flow which would result in the real world, as a consequence of the interaction of the other loads and generation sources on the transmission grid.

According to LCRA witness Reid, base and change computer modeling is a calculational technique which is necessitated by the fact that, in an integrated system, the flows on the lines are being determined by many different events and, as a practical matter, one cannot run a load flow that looks at only the element of interest. PUB witness Rhorer takes the position that, as the base and change modeling does not produce an accurate representation of changes in load flows, and as it is not possible to model the changes in load flows which would actually result, the extent of PUB's use of LCRA's transmission facilities cannot be quantified.

3. Postage Stamp Method

Arguing that the effect upon an individual utility's transmission system by any one generator tied to the ERCOT transmission system cannot as a practical matter be qualified, PUB asserts that the "postage stamp" methodology constitutes the appropriate manner in which to assign cost responsibility for the transmission investment which provides the means to wheel power. Under this method, the transmission investment of each of the ERCOT utilities would be summed and divided by the sum of the summer peak demands of each of those utilities, resulting in an ERCOT-wide transmission rate expressed in terms of dollars per kilowatt-year ($/kW-yr). According to PUB witness Rhorer, the dollar per kilowatt-year rate would then be multiplied by the amount of power to be transmitted in a given wheeling transaction, producing a total annual wheeling charge for that transaction. Interestingly, Mr. Rhorer proposes that the revenues obtained from application of that rate be apportioned among the various ERCOT utilities using megawatt mile methodology.

There are two fundamental weaknesses in this proposal which have been noted by LCRA. First, the method is devoid of any distance sensitivity. The charge for wheeling a given amount of power over a distance of 600 miles would be the same as wheeling that power a distance of only 6 miles, even though the level of transmission investment necessary to support the transaction is a direct function of the distance between the source of generation and the load area. Second, LCRA points out that the viability, if any, of the postage stamp method is dependent upon universal application within ERCOT and consequently the methodology should be considered only in the context of a future rulemaking proceeding.

4. Examiner's Recommendation

It is readily apparent from the discussion above that there are deficiencies associated with each of the basic wheeling methodologies advocated for use in this proceeding. However, of the three presented, the examiner is persuaded that the megawatt mile method represents the preferable one upon which to premise the calculation of a just and reasonable rate applicable to the wheeling of PUB's generation entitlements from Oklaunion to Brownsville.

The record reflects that the megawatt mile methodology is superior to the tie-line boundary flow and postage stamp methods in that it utilizes a unit of measurement which is sensitive to both the level of usage on individual lines within a transmission system and the distance between generation source and load. These two factors are in the examiner's opinion critical to the formulation of a wheeling rate since they both serve to define from different but necessary angles usage of transmission facilities occassioned by serving load from a remotely sited source of generation.

The major drawback to the methodology, as ably pointed out by PUB, is its use of generator-to-load computer simulations which do not in fact reflect real world load flows attributable to a wheeling transaction. However, that problem is not in the examiner's opinion as severe as is portrayed by PUB. This Commission has unequivocally accepted the validity of using base and change computer simulations to quantify the use of transmission facilities within the context of wheeling, as evidenced by the use of such simulations in both of the Commission's current wheeling rules.

With respect to the appropriateness of using generator-to-load computer simulations as opposed to generator-to-generator simulations, LCRA witness Reid testified that the issue has been discussed within ERCOT many times in years past and that, although an ERCOT task force agreed in 1983 upon the use of generator-to-generator simulations, WTU is to his knowledge the only investor owned utility within ERCOT which currently supports use of generator-to-generator simulations as opposed to generator-to-load simulations. As pointed out by Mr. Reid, generator-to-generator simulations are particularly inappropriate where the receiving entity, as is the case with PUB, has no base load generation to reduce in lieu of the reduction in load which the generator-to-load simulation assumes. Absent the existence of Oklaunion there is no way to know what the alternative generation source would be, regardless of whether the alternate generation was provided by PUB or by CP&L as the entity responsible for meeting PUB's load requirements. Accordingly, generation-to-load simulations constitute the best available load flow models for use in this proceeding. While they do not reflect actual flows which could occur, they do represent objective simulations which appear to present as accurate a picture of load flows as can be obtained in the absence of the ability to utilize generator-to-generator modeling. It should be noted that, as long as LCRA is consistent in its use of generator-to-load simulations to model usage on its system, all loads on the system are forced to flow from generator to load, thereby presumably maintaining relative comparability with respect to those loads.

PUB's proposal to allocate ERCOT's aggregate investment in transmission facilities is in the examiner's opinion wholly inappropriate for use in this proceeding because of its failure to recognize the fundamental relationship between distance and the level of transmission investment necessary to support load with remote generation. Even were one to assume the appropriateness of allocating total ERCOT transmission investment among utilities on the basis of relative loads as suggested in PUB witness Rhorer's prefiled testimony, and to further assume that that concept could be implemented in this docket on an ERCOT-wide basis, the specific methodology proposed herein by PUB is unreasonable because there is no possibility that the totality of that investment could in fact be allocated among utilities on the basis of relative loads. This is because, under the specific methodology proposed, the rate would apply solely to wheeling transactions to the exclusion of native system load. If one accepts PUB witness Rhorer's premise that in a heavily integrated system distributed load is the only relevant determinant of the need for and level of investment in transmission facilities, a proposition with which the examiner disagrees, then at a minimum the methodology would have to apply to a utility's total load regardless of whether or not wheeling was required to support that load, because in deriving the dollar per kilowatt-year rate, the total ERCOT transmission costs are divided by total ERCOT load rather than by total load being wheeled within ERCOT.

The examiner finds, based upon the preponderance of the evidence presented, that a megawatt mile method of modeling transmission system usage represents the most appropriate of the methodologies proposed by the parties for use in the limited context of this docket.

D. Calculation of Wheeling Rate

There are three discrete variables essential to the calculation of a wheeling rate in this docket: the total number of megawatt miles attributable to PUB's use of the respective transmission systems of LCRA and MEC; the total number of megawatt miles on each of those transmission systems; and the transmission costs to be allocated. Each of these variables was the subject of litigation in this docket, and accordingly, a discussion of the issues raised with respect to each follows.

1. Megawatt-miles Attributable to PUB

[2] As previously discussed, the examiner has recommended that a megawatt mile methodology be utilized to model the extent of PUB's usage of the LCRA and MEC transmission systems attributable to PUB's ownership and use of Oklaunion generation to meet its system load requirements. That recommendation obviously necessitates use of megawatt miles as the appropriate units of measurement. However, there are a number of different ways to calculate megawatt mile totals, two of which have been advocated for use in this docket. Specifically, LCRA proposes use of the vector absolute method and the Commission staff has proposed use of the positive megawatt mile method. The two methods produce very different calculations of the megawatt mile total attributable to PUB's usage and very different calculations of the system total as well, to the extent that the system total is based upon total usage as opposed to total capacity, an issue discussed later in this report.

The vector absolute method of measuring megawatt mile impacts counts the absolute value of each change in flow reflected by base and change computer simulations. In other words, all megawatt mile changes are summed without regard to whether a megawatt mile change reflects an increase or decrease in the magnitude of the flow on the line. Additionally, changes in direction of the flow on a line are counted. For instance, if the base case simulation reflected a 10 MW northward flow on a line one mile in length and the change case resulted in a 20 MW flow on that line in the opposite direction, that change would produce a vector absolute megawatt mile total of 30 for the line. Under the positive megawatt mile method, only those changes in flow which serve to increase the magnitude of the loading on a line are counted toward the total number of megawatt miles attributable to a wheeling transaction. Thus, in the example above, the positive megawatt miles attributable to the change in flow on that line would total only 10 MW because the changed vector of the flow would be disregarded.

The rationale underlying LCRA's proposed use of vector absolute megawatt miles is basically threefold. First, LCRA witness Reid argues that the unloading of a transmission line is just as much an indication of transmission system usage as is the loading of a line and, as the objective is to measure total transmission system usage, vector absolute megawatt miles best reflect that total usage level. Although the calculated number of megawatt miles of use for any individual transaction will be higher under the vector absolute method than under the positive megawatt mile method, the total number of system megawatt miles will be similarly higher, provided the system total is based upon the sum of the individual uses as opposed to capacity. Second, Mr. Reid testified that the methodology is preferable because of its relative insensitivity to alternative assumptions. According to Mr. Reid, since the results are dependent only upon the source, the destination, the transmission system, and the magnitude of the transfer the methodology produces reliable and consistent results given a wide range of alternate generation and load patterns unrelated to the specific power shipment under study. This is considered by LCRA to be a distinct advantage over the use of positive megawatt miles because of the elimination of subjective judgments concerning the order in which to model the loads on the system. When positive megawatt miles are used, it appears that the order in which various loads are layered for modeling purposes heavily influences the magnitude of the impacts attributable to each load.

Although PUB has urged a number of arguments in support of its contention that vector absolute megawatt miles should not be used to measure transmission system usage, only the following two arguments focus on the generic issue, to wit: that use of vector absolute megawatt miles requires the incorrect assumption that there are no advantages to unloading transmission lines, and that the vector absolute megawatt totals add up to far more than the capacity of the transmission line. The remaining arguments raised by PUB concern whether LCRA is applying the vector absolute method consistently and equally to all transmission system users, and whether line losses are treated equitably. Those issues will be addressed later in this report.

With respect to PUB's initial argument, the examiner is not convinced from the record in this proceeding that benefits of unloading a line are such that usage which causes a reduction in line loadings should not be treated as compensable usage, for the following reasons. First, Mr. Reid testified that increasing or decreasing the loading on a line will not affect the service life of the line. While PUB witness Rhorer testified on cross-examination that losses and thermal problems that occur in transformers have a tendency to age those components of a transmission line at a faster rate, Mr. Rhorer's testimony does not appear to support the proposition that the unloading of lines is of any substantial benefit in terms of extending the service life of transmission facilities. Second, both Mr. Rhorer and Mr. Reid appear to agree that there is no way in which the benefits of unloading a line can be quantified until the maximum capacity of the line is approached, necessitating the construction of additional facilities. Third, Mr. Reid testified that typically, the unloading of any single line or set of lines in a networked system may not necessarily equate to any improvement in the transmission system because the unloading of a line typically causes increased loading on other lines. Fourth, LCRA argues that, to the extent that transmission system costs should appropriately be apportioned among all long term firm transmission users, unloading should not be of particular relevance because any additional capacity created by the unloading does not eliminate the need to recover the embedded transmission costs from those who use the system. As unloading is a reflection of line usage, cost responsibility should be assigned to that usage. Fifth, LCRA persuasively argues that unloading attributable to a particular wheeling transaction does not necessarily provide any long term benefit because dynamic changes within the system can rapidly transform an unloading effect into a loading effect. Mr. Reid indicated on cross-examination that so long as opposing generation and load remains balanced, the capacity of a line is essentially unlimited, but that a disruption in that balance caused by the loss of a generating unit or transmission circuit may result in severe overloading. As facilities must be planned and constructed in recognition that a transaction which may in one circumstance cause a reduction in line loading may in another circumstance overload a line due to dynamic changes occurring within the transmission system, it is appropriate to assign cost responsibility to all usage regardless of whether line loadings are increased or decreased by the usage.

PUB's second generic argument, that use of vector absolute megawatt units is inappropriate because the megawatt miles totals can add up to far more than the capacity of the line, is without merit. PUB is clearly correct in its assertion that the sum of the various uses from a vector absolute measure of such uses might exceed a line's rating or thermal capability. That result is inherent in a methodology which counts toward total usage directional changes in line flows. However, the point is essentially irrelevant. Vector absolute megawatt miles attempt to measure all usage attributable to a transaction, irrespective of other usage on the system. Increases in line loadings, decreases in line loadings, and changes in the direction of flow are all indices of system usage which, taken together, serve to define a given usage in as comprehensive a fashion as possible. So long as all usage on the system is measured fairly under this methodology, the ratio of individual usage to total system usage should in the examiner's opinion provide a very accurate depiction of relative usage and a reasonable basis for allocating transmission system costs among long term firm users of the system.

With respect to the general counsel's position that positive megawatt miles constitute the best measure of system usage, the examiner must observe that staff witness Highes provided very little support for that position in his prefiled testimony or on cross-examination. Mr. Hughes took the position that megawatt mile totals will vary substantially depending upon which method of totaling megawatt miles is selected and that, as a positive megawatt mile total would fall in between the range of megawatt mile totals which result from use of other forms of megawatt mile measurement, positive megawatt miles represent a compromise position. The examiner does not find this to constitute a persuasive rationale for use of positive megawatt miles. Mr. Hughes also expressed concern that use of vector absolute megawatt miles might adversely affect wheeling customers by producing a higher statement of usage than would other megawatt mile measurements. However, the examiner finds this concern to be without foundation, so long as all long term system usage is fairly and consistently measured using vector absolute megawatt mile totals. Recommendations set forth later in this report which are intended to insure that all long term system usage is in fact measured in a consistent and equitable fashion.

Having concluded that PUB's usage of the LCRA and MEC transmission systems should be calculated using vector absolute megawatt mile totals, reference to the base and change computer simulations of record is necessary in order to determine the actual vector absolute megawatt mile totals. The impact of the PUB transaction upon LCRA's transmission system is quantified in Exhibit WJR-1 of the prefiled testimony of LCRA witness Reid. That exhibit, constituting the results of a base and change simulation performed on December 19, 1986, reflects a 2964 vector absolute megawatt mile impact upon LCRA's transmission system. The examiner recommends use of this number in calculating a wheeling rate applicable to the PUB tansaction.

With respect to MEC, it should be noted that MEC did not present a study reflecting the impact of the PUB transaction on its transmission system. Rather, it attempted to quantify the impact by extrapolating from base and change computer simulations which PUB placed into evidence. Because those studies do not reflect MEC's transmission facilities separately from the STEC/MEC pool to which it belongs, MEC witness Foreman applied a factor of .0303797 percent to the STEC/MEC impacts reflected on those studies to approximate the impacts upon MEC's facilities. Application of that ratio to Exhibit WJR-1 of Mr. Reid's testimony reflects a total impact upon MEC's system of 15.6 vector absolute megawatt miles as a consequence of the PUB transaction.

Given that MEC did not introduce into evidence an accurate quantification specific to its facilities as opposed to aggregate STEC/MEC facilities, and that even were one to accept the accuracy of the extrapolation technique used by MEC an exceedingly small impact is produced, the examiner concludes that the impact upon MEC is de minimis and that PUB should accordingly be found to owe no impact charges to MEC as a consequence of its use of Oklaunion generation to serve Brownsville load. This conclusion is bolstered by the fact that MEC has made no attempt in this proceeding to quantify the amount of compensation, if any, which should be paid it by PUB. Rather, MEC focused its case, to the exclusion of virtually all other issues, upon the appropriateness of adopting a boundary flow wheeling methodology for use in the context of remote generation. MEC has expressed concern in this docket that PUB's use of Oklaunion generation to serve

Brownsville load may have a significant impact upon MEC's facilities in the future should MEC eventually choose to expand its transmission system and interconnect to a greater degree with the ERCOT grid. However, the examiner fully concurs with PUB witness Corrigan's assertion that future events of that nature are speculative at best and inappropriate for consideration in this docket.

2. Megawatt-Miles Attributable to LCRA System

Determination of the total number of megawatt-miles attributable to the LCRA system is obviously important because that figure serves as the divisor in the calculation of a dollar per megawatt mile wheeling rate applicable to PUB, should the Commission adopt a megawatt mile method of measuring usage. Before any other issues pertinent to calculation of that system megawatt-mile total can be resolved, the Commission must determine whether the system megawatt-mile total should be calculated on the basis of total system capacity or total system usage.

P.U.C. SUBST. R. 23.67 currently provides for the calculation of total system megawatt mileage based upon the theoretical capacity of a given transmission system. LCRA and the Commission staff, however, propose to calculate total system megawatt mileage based upon a total system usage. According to LCRA witness Reid, the divisor in the megawatt mile unit rate should reflect total system usage because long term firm users of the transmission system should share equally in the long term costs of the transmission system, regardless of whether those users are native system full requirement customers or off-system users. It would appear that the use of total system capacity in the calculation of the megawatt mile unit rate causes the occurence of cost subsidies because usage is never equal to theoretical system capacity. This is due, among other reasons, to the need to maintain circuit redundancy and unused capacity necessary to handle any adverse contingency without jeopardizing system reliability. If the megawatt mile unit rate is calculated using system capacity as the divisor, the cost of unused capacity falls upon the native system customer as a consequence of the incomplete allocation of total transmission system costs. This observation is essentially confirmed by staff witness Hughes, who testified that an arithmetically meaningless result is achieved in calculating wheeling charges under a megawatt mile methodology unless total system megawatt mileage is computed in exactly the same manner as the megawatt mile usage of the wheeling customer.

Although PUB's witnesses did not speak directly to the issue of usage versus capacity, it is a fair characterization to say that PUB would favor a capacity based measure of total system megawatt mileage because the failure of that methodology to achieve a full allocation of costs would produce a lower rate per megawatt mile. There are three bases for this observation. First, PUB believes that the higher the wheeling rate for remote generation, the greater the likelihood that a disincentive to the remote siting of generating plants will emerge. Second, the effect of PUB's "postage stamp" methodology is similar to that of a megawatt mile unit rate which incorporates a capacity-based measure of system mileage. This is evident from the fact that the dollar per kilowatt year rate developed under PUB's methodology would be based upon division of total ERCOT transmission costs by total ERCOT load, but application of that rate would apply solely to power actually wheeled, thus preventing the full allocation of transmission costs among the users of the facilities. Third, PUB takes the position in its brief that if the Commission chooses to base remote generation wheeling rates upon long term incremental costs, an issue discussed later in this report, system costs should be allocated based upon capacity rather than usage, in the fashion contemplated by P.U.C. SUBST. R. 23.67.

In the examiner's opinion, the long term life-of-the-plant nature of wheeling transactions involving remote generation and the lack of interruptibility of that power, since it is invariably utilized for base load purposes, together sufficiently distinguish remote generation wheeling transactions from those transactions covered by P.U.C. SUBST. R. 23.67 to warrant the conclusion that the Commission's policy decision to use a capacity based measurement of system megawatt mileage for purposes of that rule is not appropriately applicable by analogy in this instance. The examiner joins in LCRA witness Reid's observation that, while there may exist public policy arguments which support the disproportionately low wheeling rates which result from use of a capacity based measurement of system megawatt mileage in the context of those wheeling transactions covered by the Commission's current substantive rules, public policy should not favor subsidization by LCRA's native system customers of the true costs of long term firm transmission service used to support another utility's remote generation. In fact, public policy should, in the examiner's opinion, favor the avoidance of subsidization of transmission costs attributable to remote generation. Should the Commission agree with this position, then the avoidance of subsidization requires that transmission costs be allocated among all long term firm users based upon the ratio of each entity's individual usage to total system usage, as proposed by LCRA and the Commission staff. The examiner does not accept the contention that this course of action will indiscriminately discourage remote generation. Rather it will discourage solely that participation in remote generation which requires for economic viability the avoidance of the true costs of transmission services associated with serving load from that generation source.

Should the Commission accept the examiner's recommendation that total system megawatt mileage be calculated based upon total system usage as opposed to total capacity, there are three issues pertinent to calculation of that total which must be addressed, to wit: 1) the omission of usage of LCRA's transmission facilities attributable to CP&L's use of Oklaunion generation to serve its native system load; 2) whether LCRA should be permitted to net its inadvertent flows on other systems against the inadvertent flows occurring on the LCRA system; and 3) whether to, and if so, how to eliminate inconsistency in the calculation of usage of the system by native system customers and off-system users. A discussion of each of these issues follows.

a. <u>Omission of CP&L usage</u>. Although CP&L owns an interest in Oklaunion and that generation unit is unquestionably remotely sited with respect to CP&L's service territory, PUB has correctly pointed out that LCRA has not included CP&L

within LCRA's list of long term firm wheelers, nor it appears has the megawatt mileage attributable to CP&L's wheeling of Oklaunion generation been included within the system megawatt mile total. On cross-examination LCRA witness Reid testified that CP&L was not treated as a long term firm wheeler by LCRA because there presently existed no term firm obligation relative to CP&L. At such time as CP&L and LCRA enter into a wheeling contract, Mr. Reid testified that CP&L would be categorized as a long term firm wheeler. The examiner finds that there is no distinction in the quality of the usage imposed upon LCRA's system by PUB and CP&L with respect to the wheeling of power from Oklaunion. Therefore, regardless of whether or not CP&L has contracted with LCRA for wheeling services, the megawatt mile usage of LCRA's system attributable to CP&L's ownership interest in Oklaunion must in the examiner's opinion be included within the system megawatt mile total for purposes of calculating a dollar per megawatt mile wheeling rate.

b. Inadvertent flows. The record reflects that a utility's operation of generation facilities located within its service area to serve native system load causes megawatt mile impacts upon the transmission system of other ERCOT utilities. The present practice among ERCOT utilities, according to LCRA witness Reid, is to treat these inadvertent flows which each utility imposes on the others as a "wash". No attempt is made within ERCOT to charge for inadvertent flows. Exhibit No. 4 attached to PUB witness Rhorer's prefiled testimony reflects that the inadvertent flows imposed upon LCRA's transmission system by the other ERCOT utilities total 95,245 vector absolute megawatt miles, and that the inadvertent flows which LCRA imposes upon the transmission systems of the other ERCOT utilities total 55,304 vector absolute megawatt miles. Clearly in LCRA's instance there is no "wash", as netting the inadvertent flows still leaves LCRA with an impact of 39,941 megawatt miles imposed by the inavertent flows of other ERCOT utilities. This is undoubtedly a consequence of LCRA's central location within the ERCOT grid.

PUB witness Rhorer testified that Mr. Reid understated total system megawatt-miles by omitting from that total the relative usage of the LCRA system by other ERCOT utilities. This statement is not entirely correct. LCRA witness Reid testified that the total system megawatt mile usage which he utilized includes within it a component attributable to the net difference between LCRA's inadvertent flows and the inadvertent flows imposed on LCRA's transmission system by the other ERCOT utilities.

It is clear from the record that LCRA in fact took inadvertent flows into account in calculating the system megawatt mile total. However, the examiner cannot accept the way in which LCRA accounted for those flows. Netting LCRA's inadvertent flows against those imposed by the other ERCOT utilities is in the examiner's view improper because LCRA's impacts upon the other ERCOT utilities are attributable entirely to LCRA's use of its generating units to meet its native system load. As those megawatt miles impacts are in no way caused by off system customers, they should not be offset against inadvertent flows on the LCRA system for purposes of calculating total system megawatt mileage. Mr. Reid testified on cross-examination that if the respective inadvertent flows of LCRA are not netted against those of the other ERCOT utilities, it would be necessary to increase the level of transmission costs to be allocated, in recognition of the higher transmission facility costs which would exist in the absence of the efficiencies afforded by interconnection. However, the examiner would point out that, if LCRA were not interconnected to the ERCOT grid, use of LCRA's transmission facilities to serve PUB's native system load with Oklaunion generation would not be necessary. If PUB is to pay wheeling charges to LCRA based upon PUB's proportionate use of LCRA's transmission facilities, PUB's rate should be based upon LCRA's efficient transmission facilities costs, which includes the economies inherent in interconnection.

The examiner recommends that, in calculating total system megawatt mileage, the inadvertent flows attributable to use of LCRA's transmission system not be offset by the inadvertent flows on other utility systems attributable to LCRA.

c. Consistency in calculating system usage. By far the most difficult issue with respect to calculation of total system megawatt mileage concerns consistency in the calculation of the individual uses which must be summed to calculate total system usage. It appears that the sum of each individual use of the system will produce a larger number than if those individual uses are aggregated into classes and the class uses are then summed. This is because, under any megawatt mile methodology, if multiple transactions are combined and modeled as one transaction, reciprocal impacts attributable to the component transactions will be cancelled out and will not be reflected in the statement of total megawatt mile usage. For instance, if one transaction by itself causes a 10 megawatt mile increase in line flow and a second transaction by itself causes a 10 megawatt decrease in line flow, the sum of those two transactions, under a positive megawatt mile method of totaling megawatt mileage, would be 10 megawatt miles. However, if the two transactions were modeled as one transaction, they would cancel each other out and there would be no megawatt mile impact associated with the transaction. This phenomenon is enhanced by use of vector absolute megawatt miles because of the added element of direction of flow.

PUB witness Rhorer has pointed out in this docket what appears to the examiner to be a gross deficiency in the manner in which LCRA has calculated total system megawatt mileage. Specifically, although LCRA performed base and change simulations for the long term firm uses of the LCRA system imposed by the San Miguel to BEPC transfer, the Texas Gulf to TUEC transfer, the Inter-North Cogen to TUEC transfer and the Oklaunion to PUB transfer, LCRA did not perform base and change simulations for the purpose of measuring the megawatt mile usage attributable to each of its full requirements customers, or even to the group as a whole. Instead, LCRA witness Reid multiplied projected 1987 summer peak flows on each LCRA transmission circuit (assuming the presence of all long term firm wheeling transactions) by the length of each circuit, summed the megawatt miles calculated for each circuit, and utilized the resulting megawatt mile figure of 93,525 as a surrogate for the megawatt mile usage attributable to LCRA's full requirements customers and inadvertent flows on the system. In this manner, LCRA permitted all reciprocal megawatt mile effects to be netted out in the calculation of the megawatt miles attributable to all long term firm usage on the LCRA system, with the exception of the usage attributable to the San Miguel to BEPC transfer, the Texas Gulf to TUEC transfer, The Inter-North Cogen to TUEC transfer and the Oklaunion to PUB transfer. The effect of LCRA's action, if permitted, would be to shift a disproportionate share of embedded transmission facility costs to the above enumerated non-native system users, since the understatement of total system would cause an excessive dollar per megawatt mile wheeling rate.

When the examiner questioned Mr. Reid regarding his calculation of megawatt mileage attributable to LCRA's full requirements customers, Mr. Reid stated that the surrogate number he used was higher than what would be produced under a base and change case approach. That is technically correct. However, he failed to note two important points. First, the surrogate number which he used was intended to include inadvertent flows on the system attributable to other ERCOT utilities. The base and change simulations attached to PUB witness Rhorer's testimony reflect a usage of 65,884 vector absolute megawatt miles attributable to LCRA's native system uses. When combined with the 95,245 megawatt miles of inadvertent flows on the LCRA system, the resultant figure far exceeds the surrogate measure of native system usage employed by Mr. Reid. Second, Mr. Reid failed to note that his answer assumed that all uses of the system by LCRA's full requirements customers would be modeled as one transaction. Mr. Reid testified on cross-examination by PUB that he did not know what usage figure would result were the usage attributable to each of LCRA's full requirements customers separately measured.

It appears to the examiner that equitable application of LCRA's vector absolute megawatt mile methodology requires, at a minimum, rejection of Mr. Reid's surrogate measure of native system usage in favor of measurement derived from base and change simulations. It further appears that the most accurate measurement of total system usage would be obtained by running base and change simulations for each of the 90 delivery points on the LCRA system since LCRA's usage is comprised of multiple load areas and multiple sources of generation and no convincing rationale has been advanced for treating all native system uses as one transaction. The only rationale advanced was Mr. Reid's testimony that matching areas of load responsibility to generators would in his opinion yield a consistent set of measures for calculating usage. For the reasons stated above, the examiner cannot agree.

The record reflects that it is possible to separately calculate the vector absolute megawatt mile effect of delivering power from LCRA's collective generation sources to each of LCRA's delivery parts. However, the record does not reflect the amount of computer time which would be necessary to run all of those base and change simulations. Therefore, the examiner proposes both a primary and an alternative recommendation. The preferred recommendation is that LCRA run base and change simulations of the vector absolute megawatt mile changes in flow attributable to serving each of LCRA's 90 delivery points from its collective generation sources. The resulting megawatt miles should then be added to the megawatt miles attributable to the un-netted megawatt miles of inadvertent flows on the system and the megawatt miles attributable to the San Miguel to BEPC transfer, the Texas Gulf Cogen to TUEC transfer, the Inter-North Cogen to TUEC transfer, the Oklaunion to CP&L transfer, and the Oklaunion to PUB transfer, resulting in a statement of total system megawatt mileage to be used as the divisor in the calculation of a dollar per megawatt mile wheeling rate applicable to PUB.

In the event LCRA indicates in its exceptions to this report that performance of base and change simulations for each of the LCRA delivery points is not reasonably feasible, the examiner recommends in the alternative that all long term firm use of the LCRA system be divided into two separate groups comprised of use by native system customers and use by non-native system entities, and that all uses within each group be treated as one transaction for purposes of running base and change simulations. This should produce comparable net vector absolute megawatt mile usages for each group. The transmission revenue requirement attributable to long term firm users of the transmission system should then be allocated between the two groups on the basis of the ratio of each group's usage to the sum of the group uses. A dollar per megawatt mile rate would then be calculated for the non-native group by dividing the revenue requirement assigned to that group by the sum of all of the non-netted megawatt mile uses within that group. This methodology eliminates the bias against non-native system usage inherent in LCRA's proposal and avoids the need to run base and change simulations for each of LCRA's delivery points.

d. Conclusion. LCRA witness Reid calculated total system megawatt miles as follows:

Long-Term Firm Customer	MW Miles
Full requirements customers	93,525
San Miguel to BEPC	11,113
Texas Gulf Cogen to TUEC	2,364
Inter-North Cogen to TUEC	9,442
Oklaunion to PUB	2,964
TOTAL	119,408

The examiner's recommendations require adjustment of the above calculation to reflect the megawatt mileage attributable to the CP&L/Oklaunion transaction, the full level of inadvertent flows imposed upon the system by other ERCOT utilities (without offset for LCRA's inadvertent flows on other systems), and the sum of the megawatt mile totals applicable to the provision of power to each of LCRA's delivery points from its collective generation sources calculated through use of separate base and change simulations.

Should the examiner's alternative recommendation be adopted, the above calculation must be adjusted to reflect the net vector absolute megawatt mile usage of LCRA's native system customers as determined by base and change simulations, and the net vector absolute megawatt mile usage of LCRA's non-native system users.

Unfortunately the data necessary to calculate total system megawatt miles under either scenario is not contained in the evidentiary record and is unavailable until such time as the necessary base and change computer simulations are run. Therefore, the examiner recommends that after the Commission renders its decision on the issues in dispute in this docket, the case be remanded to the examiner for the limited purpose of admitting into the evidentiary record all data necessary to the calculation of the specific wheeling rate to be applied to PUB, or if the data can be assembled and calculations made without such a limited remand, the parties (chiefly LCRA) so indicate in exceptions and replies.

3. Total Transmission System Costs

LCRA witness Angela Taylor sponsored the calculation of LCRA's firm transmission revenue requirement. Ms. Taylor's calculations produce a firm transmission revenue requirement of $15,300,643 to be allocated among the long term firm users of LCRA's transmission system. Ms. Taylor's calculation reflects the revenue requirement established in Docket No. 6027, the most recent LCRA rate case at the time this docket was initiated. The firm transmission revenue requirement calculated by Ms. Taylor is comprised of the following components:

GROSS REVENUE REQUIREMENT			
O&M Expense	$ 8,635,460		
Debt Service	10,599,010		
Coverage	2,325,697		
TOTAL GROSS REVENUE		$21,560,167	
Less Adj. to Examiner's Report		- 213,588	
ADJUSTED TOTAL GROSS REVENUE			$21,346,579
OTHER REVENUES		$ 9,361,971	
Wheeling	4,250,637		
Miscellaneous	124,062		
Equipment	21,001		
SUBTOTAL		-4,395,700	
NET TOTAL OTHER REVENUE			-4,966,271
NET TRANSMISSION REVENUE REQUIREMENT			16,380,308
As Available Wheeling Revenue			-1,079,665
FIRM TRANSMISSION REVENUE REQUIREMENT			$15,300,643

The only contested aspect of Ms. Taylor's calculation concerns the inclusion of $124,062 in miscellaneous electric revenues as a component element of the firm transmission revenue requirement. Staff witness George Mentrup, upon review of LCRA's cost of service study, was unable to determine whether the miscellaneous revenues included in LCRA witness Taylor's calculation were derived from base rate services or from incidental activities. Those revenues are appropriately to be excluded from the calculation only in the event they are generated from incidental activities. Due to Mr. Mentrup's inability to obtain clarification of the origin of those revenues, Mr. Mentrup recommended that those miscellaneous revenues be included in the calculation of the firm transmission revenue requirement as a revenue requirement offset.

LCRA did not rebut Mr. Mentrup's testimony on this issue nor was the issue clarified through cross-examination. Therefore, the examiner recommends adoption of Mr. Mentrup's proposed adjustment, resulting in an adjusted firm transmission revenue requirement of $15,176,581.

The examiner would note that, although the transmission revenue requirement recommended herein is derived from Docket No. 6027, LCRA was granted a rate increase subsequent to that docket by Final Order issued on October 22, 1987 in Docket No. 7512, and a revised revenue requirement was determined at that time. As the wheeling rate established for PUB will, by agreement of the parties, be applied retroactively to the date of commercial operation of Oklaunion, the examiner believes the most efficient course of action would be to utilize the revenue requirement recommended herein pending final action on LCRA's current application for a rate increase, which is pending in Docket No. 8032.

Aside from any issue concerning the correctness of the firm transmission revenue requirement calculated by Ms. Taylor, there exists a more fundamental issue which should be briefly addressed. Although Mr. Mentrup supports the use of LCRA's embedded transmission facility costs in the calculation of a wheeling rate for PUB, Mr. Mentrup testified in the alternative that costs other than embedded transmission facility costs could appropriately be used to calculate the rate. Mr. Mentrup asserted two arguments which he believes support the contention that the unit costs charged to firm wheeling customers need not equal those paid by native system customers, as is the case under the embedded cost approach supported by LCRA and the Commission staff in this docket. First, Mr. Mentrup notes that native customers are provided an integrated product in the sense that LCRA both produces and delivers electricity for their use, while wheeling customers receive unbundled transmission service, and that a utility's planning decisions and cost incurrences with regard to generation and distribution are not necessarily independent of the transmission system configuration. According to Mr. Mentrup, in planning to serve its customers in a least cost manner, LCRA must plan for the size, type, and timing of additional generation, transmission and distribution equipment. Those plans and costs for LCRA's generation and distribution facilities may change as a result of the addition of firm wheeling service and, to the extent that native system customers have a right to the least-cost evolution of the LCRA system necessary to serve them, then the impacts of providing firm wheeling may be recognizable in the wheeling price. Mr. Mentrup refers to the impact of the existence of firm wheeling customers as "external costs".

Second, Mr. Mentrup argues that native system customers and wheeling customers should not necessarily face the same unit cost because native system customers obtain an integrated product, and generation and transmission tend to overlap in function. Mr. Mentrup argues that, in a sense, transmission lines may act as a substitute for generation because the addition of transmission lines may allow for fewer and less costly generating units to be installed.

According to Mr. Mentrup, as an alternative to the staff's primary recommendation that LCRA's embedded costs be used, allocable costs could be determined using any of the following three approaches: 1) long-run incremental cost plus PUB's share of any external costs or benefits imposed on LCRA's distribution and generation costs by firm wheelers as a group; 2) straight long-run incremental cost; or 3) embedded cost plus PUB's share of any external costs or benefits likely to be imposed of LCRA's native customers' distribution and generation costs by firm wheelers as a group.

Were the wheeling rate to be calculated using long-run incremental costs, Mr. Mentrup testified that the calculation of those costs would be similar to avoided cost calculations currently performed for determining capacity payments to qualifying facilities, or alternatively, that an estimate of the change in transmission investment costs per megawatt mile could be calculated.

The examiner does not recommend adoption of Mr. Mentrup's alternative recommendations, for two reasons. First, those positions were argued solely in the alternative, the staff's primary position being use of the transmission revenue requirement calculated by LCRA witness Taylor, as adjusted by Mr. Mentrup. No other party advocated the use of long run incremental costs. Second, those approaches were not sufficiently developed during the hearing to permit their use. Mr. Mentrup's alternate proposals are sketchy at best. Substantial additional evidence would be required before the examiner could make recommendations concerning those alternate proposals. While the alternative approaches to calculating allocable costs may prove a fruitful basis of discussion in a future rulemaking proceeding, the record developed in this docket does not support their use.

E. Treatment of Line Losses

There are two separate charges which together comprise the total charge payable for firm wheeling service: the facilities charge and the charge for line losses. The parties to this proceeding focused their arguments primarily upon the manner in which the facilities charge would be developed, rather than the manner in which line losses should be handled. However, PUB has disputed the manner in which LCRA proposes to treat line losses.

Line losses represent the thermal loss that occurs when power flows over a transmission line. The longer the distance, the greater the potential line loss. It would appear that a wheeling transaction can serve to either increase or decrease a utility's line losses. It further appears that it is difficult if not impossible to accurately measure line losses in the context of a wheeling transaction.

LCRA has proposed that PUB compensate it for any line loss increases attributable to the wheeling of power from Oklaunion to PUB's service area. LCRA's proposed tariff fails to specify exactly how those losses would be measured. PUB opposes LCRA's proposed treatment of line losses for two reasons. First, PUB asserts that use of generation-to-load base and change simulations cause an overstatement of line losses because they assume Oklaunion power actually traverses the full distance between Oklaunion and Brownsville. Second, PUB asserts that if PUB is to bear a full prorata share of LCRA's embedded transmission facility costs, it is unfair for LCRA to charge for any increased losses while retaining the benefits of any decreased losses.

PUB witness Rhorer proposed that line losses be calculated on an ERCOT-wide average loss basis, paralleling the manner in which transmission costs are allocated under PUB's "postage stamp" facilities rate proposal. However, that methodology would appear to the examiner to be inappropriate absent Commission acceptance of the "postage stamp" methodology proposed by PUB. Mr. Rhorer proposed no alternative treatment of line losses in the event the "postage stamp" methodology was rejected.

After consideration of the scant evidence of record on this issue, the examiner finds that LCRA has failed to meet its burden of proof with respect to its proposed treatment of line losses. The rationale behind LCRA's proposal that LCRA customers retain the benefits of any reduced line losses attributable to the PUB/Oklaunion wheeling transaction is singularly lacking. The best argument that LCRA witness Reid could marshall was that, as long as the wheeling customer is not being charged, the customer should be indifferent to the fact that the benefits of reduced losses flow solely to native system customers.

The examiner is unable to respond to the assertion that base and change simulations will result in an inaccurate statement of line losses attributable to a wheeling transaction, other than to comment that there appear to be no methodologies by which line losses can be accurately measured. The problem of calculating line losses for the Oklaunion/PUB transaction is in the examiner's opinion similar to the problem of calculating losses attributable to wheeling by cogenerators. In that instance, the appropriate methodology is spelled out in a Commission substantive rule. Absent any better alternative, the examiner proposes that the methodology for calculation of line losses set forth in P.U.C. SUBST. R. 23.66 be applied to the instant transaction.

P.U.C. SUBST. R. 23.66(d)(5)(F) provides as follows:

> **(F) Provision for losses.** Increases or decreases in losses incurred by an impacted utility due to a transaction shall be determined from the scheduled transfer used in conjunction with loss matrices produced by the Electric Reliability Council of Texas Engineering Subcommittee or upon average system losses for increased losses at the option of the qualifying facility. Increases or decreases in losses shall be repaid in kind at the time of the transfer if practical or if such repayment is not practical, accumulated in peak and off-peak accounts for later payback. If both the impacted utility and the purchasing utility agree payments and credits for losses may be in cash.

Under the above methodology, PUB's concern about the inequitable treatment of reduced line losses is resolved, because both increases and decreases in losses are flowed through to the wheeling customer. Further, it permits losses to be calculated using either the loss matrices developed by ERCOT or average system losses, at the option of the wheeling customer.

The examiner recommends that the Commission find the line loss methodology set forth in P.U.C. SUBST. R. 23.66(d)(5)(F) to constitute the appropriate manner in which to calculate lines losses attributable to the Oklaunion/PUB transaction.

F. Summary of Recommendations

In summary, the examiner finds that the use of Oklaunion generation to meet PUB's load requirements produces a compensable impact upon the transmission systems of LCRA and MEC. Further, the examiner finds that a megawatt mile methodology constitutes the most reasonable way to measure that impact. Of the numerous ways in which megawatt mile totals can be calculated, the examiner finds that all uses of the LCRA and MEC transmission systems should most appropriately be measured by totals developed through use of vector absolute megawatt miles. The examiner finds PUB's usage of the LCRA system to total 2964 vector absolute megawatt miles. However, the examiner finds PUB's usage of MEC's facilities to be so slight that it must be considered de minimis in nature. Consequently, no compensation is owed to MEC by PUB for that usage.

For purposes of calculating a dollar per megawatt mile unit rate, the examiner finds LCRA to have a firm transmission revenue requirement of $15,116,581. Division of that figure by total system vector absolute megawatt mileage will produce an appropriate dollar per megawatt mile unit rate applicable to PUB.

The examiner finds that accurate calculation of that system total requires that LCRA run base and change simulations of the vector absolute megawatt-mile changes in flow attributable to serving each of LCRA's 90 delivery points from its collective generation sources, and that the resulting megawatt miles then be added to the megawatt miles attributable to the un-netted megawatt miles of inadvertent flows on the system, and the megawatt miles attributable to the San Miguel/BEPC transfer, the Texas Gulf Cogen/TUEC transfer, the Inter-North Cogen/TUEC transfer, the Oklaunion/CP&L transfer and the Oklaunion/PUB transfer. In the alternative, should the conduct of base and change simulations for each of LCRA's delivery points not be deemed reasonably feasible, the examiner finds that all long term firm use of the LCRA transmission system should be divided into two separate groups comprised of use by native system customers and use by non-native system customers, and that all uses within each group should be treated as one transaction for purposes of running base and change simulations. The transmission revenue requirement attributable to long term firm users should then be allocated between the two groups on the basis of the ratio of each group's usage to the sum of the group uses. A dollar per megawatt mile rate should be calculated for the non-native group by dividing the group revenue requirement by the sum of all of the non-netted group megawatt mile uses.

For purposes of calculating the dollar level of the facilities charges owed to LCRA by PUB, the dollar per megawatt mile unit rate should be multiplied by PUB's vector absolute megawatt mile usage of the LCRA system. The examiner finds that charges for line losses should be calculated in accordance with the methodology established in P.U.C. SUBST. R. 23.66(d)(5)(F).

The examiner finds that the data necessary to accurately calculate total system vector absolute megawatt mileage is not contained in the record evidence. Therefore, in order to calculate the specific dollar per megawatt mile unit rate which results from the above recommendations, it will be necessary for LCRA to perform additional base and change computer simulations. Consequently, the examiner recommends that this proceeding be remanded, after all methodological issues have been resolved by the Commission, for the limited purposes of admitting into the evidentiary record all data necessary to the calculation of the specific wheeling rate to be applied to PUB, calculation of that rate and incorporation of the resultant rate as well as the recommendations made herein into the text of the proposed LCRA tariff applicable to the PUB/Oklaunion transaction.

The examiner strongly recommends that the Commission initiate a rulemaking proceeding upon conclusion of this docket for the purpose of formulating a uniform statewide policy with respect to the wheeling of power from remotely sited generation facilities. At such time as the Commission implements a wheeling rule applicable to remote generation, the wheeling rates established in this docket should be superseded on a prospective basis by revised rates calculated in accordance with the wheeling methodology incorporated in that substantive rule.

Finally, due to the limited scope of this docket, the examiner recommends that no precedential value be assigned this docket in future proceedings.

IV. Findings of Fact and Conclusions of Law

The examiner further recommends adoption of the following findings of fact and conclusions of law:

A. Findings of Fact

1. This docket was initiated on August 19, 1986, by final Order of the Commission in Docket No. 6890, styled Application of Central Power and Light

<u>Company and the Public Utilities Board of the City of Brownsville for Approval of the Sale and Purchase of an Interest in Oklaunion Unit No. 1</u> (August 19, 1986).

2. Prehearing conferences were convened in this docket on September 9, 1986, and October 20, 1986. The hearing on the merits was convened on July 7, 1987 and adjourned on July 20, 1987, after five days of actual hearing. Numerous parties participated in all or part of the proceedings as reflected in the procedural history set out in Section I of this report.

3. The Public Utilities Board of the City of Brownsville (PUB) provided individual notice of this proceeding to all ERCOT utilities. Further, notice of the pendency of this proceeding was published in the October 3, 1986, issue of the <u>Texas Register</u>.

4. Oklaunion Unit No. 1 is located in Wilbarger County near the Texas/Oklahoma border. PUB's service territory is located more than 600 miles away in the southern-most tip of Texas.

5. PUB owns a 10.16 percent undivided interest in Oklaunion Unit No. 1 (Oklaunion) and utilizes its Oklaunion entitlements to meet its native system load requirements.

6. LCRA and MEC claim to be owed wheeling charges for the use made of their transmission facilities by PUB as a consequence of PUB's use of Oklaunion generation to meet its system load requirements.

7. To the extent that it can be shown that PUB's use of Oklaunion generation to meet Brownsville's load requirements involves the use of LCRA's and MEC's transmission facilities, an impact exists within the intended meaning of the final Order in Docket 6890.

8. PUB owns only 41.9 miles of transmission line out of a total of 30,600 miles of line comprising the integrated ERCOT transmission grid, and owns no transmission facilities connecting Oklaunion to the PUB load area.

9. PUB is wholly dependent upon the transmission facilities of other ERCOT utilities in order to enable it to meet its load requirements with power generated by Oklaunion.

10. PUB has secured wheeling contracts with each of the utility intervenors in Docket No. 6890 with the exception of LCRA, with whom PUB could not reach agreement.

11. Flow of power within an integrated transmission grid is a function of the existence and location of the loads and generation sources connected to the grid.

12. The existence and location of Oklaunion causes changes in transmission line loadings on the lines owned by LCRA and MEC as well as upon lines owned by other ERCOT utilities.

13. The transfer of an ownership interest in Oklaunion from CP&L to PUB causes no change in the power flows on any of the transmission lines within the ERCOT integrated transmission grid.

14. Use of Oklaunion generation to meet Brownsville load requirements necessarily involves the use of the individual transmission systems comprising the interconnected ERCOT grid, including the facilities owned by LCRA and MEC.

15. PUB's certificate of convenience and necessity was conditioned by the Commission in Docket No. 6890 upon payment by PUB of all wheeling charges associated with PUB's ownership interest in Oklaunion which the Commission may find to be appropriate.

16. The fact that inadvertent flows on transmission facilities necessarily occur as a consequence of interconnection with an integrated transmission grid should not absolve PUB from responsibility for wheeling charges.

17. PUB has voluntarily availed itself of one of the substantial benefits which flow from an integrated generation and transmission grid, to wit: the ability to engage in remote generation without the need to construct transmission

facilities connecting the generation to the load area, creating a reciprocal obligation to bear in part the costs of the substantial transmission facilities needed to support that integrated grid.

18. The different treatment afforded remote generation and non-remote generation by LCRA is reasonable since PUB must rely upon the transmission investment of other utilities in order to serve its load with Oklaunion generation, while the owners of non-remote generation are capable of independently serving native system load from their own transmission facilities.

19. Neither the operation of Oklaunion nor its use to meet PUB's load requirements will affect the reliability or interchange ability of the LCRA and MEC transmission systems.

20. Transmission facilities within ERCOT are planned and built with sufficient capacity and line redundancy to assure the ability of those facilities to handle the loads placed upon them under multiple adverse contingencies.

21. It is wholly unrealistic to premise the payment of compensation for the use of transmission facilities upon a demonstration of adverse effects upon system reliability or interchange ability.

22. The ERCOT Operating Guides support the right to compensation claimed by LCRA and MEC.

23. The acquisition of an ownership interest in Oklaunion enabled PUB to replace its power purchases from CP&L with power generated by Oklaunion.

24. PUB's decision to purchase an interest in Oklaunion was motivated in part by the favorable economics of that plant.

25. If PUB's power costs are to be determined by the capital costs and operating costs of Oklaunion, PUB's power costs must include responsibility for the transmission facilities which must be used to support PUB's load

requirements from that plant.

26. As LCRA, MEC and other ERCOT utilities have incurred substantial costs to construct transmission facilities necessary to support power flows throughout the ERCOT system and those facilities are necessarily used by PUB to serve its load from generation in North Texas, the payment of compensation to the owners of those facilities is necessary to avoid the subsidization by other utility ratepayers of the true costs of serving PUB's load.

27. Compensation for use of facilities should be paid to all of the utilities whose facilities are used rather than to only certain arbitrarily designated utilities.

28. LCRA and MEC are entitled to compensation from PUB for any significant use of their facilities as a consequence of PUB's use of Oklaunion generation to meet its load requirements.

29. The wheeling methodology upon which a transaction is to be premised determines the appropriate unit of measurement for quantifying usage.

30. The tie-line flow wheeling methodology advocated by MEC assesses transmission system use by measurement of changes in power flows on utility-to-utility tie lines.

31. The tie-line boundary flow method of quantifying transmission system usage is inappropriate because megawatts constitutes meaningless units of measurement within a wheeling context; the methodology incorrectly assumes that all utilities are the same size and that all lines are used equally to transmit power; the large number of interconnections within ERCOT can cause the same megawatts to computationally enter, exit and re-enter the same system several times; and the methodology suffers from "pancaking".

32. Megawatt mile methodologies utilize base and change computer simulations to contrast the flow of power on transmission lines given the alternate presence

and absence of a particular wheeling transaction.

33. Under the megawatt mile method, the change in megawatt flow on each individual transmission line is measured and then multiplied by the length of the line, producing a measurement of usage of the line expressed in megawatt miles. The megawatt mile impacts on each line are then summed to produce a measurement of total usage of the transmission system occasioned by a particular transaction.

34. The generation-to-load base and change computer simulations used by LCRA do not model the changes in flow which actually occur as a consequence of a given transaction, but rather, the hypothetical changes in flow which would occur were one to assume that power being wheeled in fact physically flows from the designated source of generation to the designated load area.

35. One cannot determine which load is being served from a particular generating unit connected to an integrated transmission system because power flows to the loads closest to it as defined by the location and size of the other generation sources and loads tied to the grid.

36. The "postage stamp" methodology advocated by PUB requires that the transmission investments of all ERCOT utilities be summed and divided by the sum of the summer peak demand of all ERCOT utilities, resulting in an ERCOT-wide transmission rate expressed in terms of dollars per kilowatt year, which rate would then be multiplied by the amount of power to be wheeled in a given transaction, producing a total annual charge for that transaction.

37. The "postage stamp" methodology is fatally flawed as a consequence of its lack of distance sensitivity.

38. The viability of PUB's "postage stamp" method is dependent upon universal application within ERCOT, a result which cannot be achieved in this docket.

39. The megawatt mile methodology is superior to the tie-line boundary flow and

"postage stamp" methods because of its use of a unit of measurement which is sensitive to both the level of usage on individual lines within a transmission system and the distance between generation source and load.

40. The major drawback to the megawatt mile methodology is its use of generation-to-load computer simulations which do not in fact simulate real world load flows attributable to a wheeling transaction.

41. The Commission has unequivocably accepted the validity of using base and change simulations to quantify the use of transmission facilities within the context of wheeling, as evidenced by the use of such simulations in the Commission's current wheeling rules.

42. Generation-to-load simulations constitute the best available load flow models for use in this proceeding and, while they do not reflect actual flows which would occur, they do represent objective simulations which appear to present as accurate a picture of load flows as can be obtained in the absence of the ability to use generation-to-generation modeling.

43. As long as LCRA is consistent in its use of generation-to-load simulations to model usage on its system, all loads on the system are forced to flow from generator to load, thereby presumably maintaining relative comparability with respect to those loads.

44. A megawatt mile method of modeling transmission system usage represents the most appropriate of the methodologies proposed by the parties for use in the limited context of this docket.

45. There are three discrete variables essential to the calculation of a wheeling rate in this docket: 1) the total number of megawatt miles attributable to PUB's use of the respective transmission systems of LCRA and MEC; 2) the total number of megawatt miles on each of those transmission systems; and the dollar amount of the transmission costs to be allocated.

46. There exist multiple ways in which to calculate megawatt mile totals.

47. The vector absolute method of measuring megawatt mile impacts counts the absolute value of the changes in magnitude and vector of flows.

48. The positive megawatt mile method of measuring megawatt mile impacts counts only those changes in flow which serve to increase the magnitude of flow on a line.

49. Unloading of a transmission line and changes in the direction of flow are just as much indications of transmission system usage as is the loading of a line.

50. Although the calculated number of megawatt miles of use for any individual transaction will be higher under the vector absolute method than under the positive megawatt mile method, the total number of system megawatt miles will be similarly higher, provided the system total is based upon the sum of the individual uses as opposed to system capacity.

51. The vector absolute method produces reliable and consistent results given a wide range of alternate generation and load patterns unrelated to the specific power shipment under study.

52. The unloading of lines is not of any substantial benefit in terms of extending the service life of transmission facilities.

53. There is no way in which any benefit of unloading a line can be quantified until the maximum capacity of the line is approached, necessitating the construction of additional facilities.

54. The unloading of any single line or set of lines in an integrated system may not necessarily equate to any improvement in the transmission system because the unloading of a line typically causes increased loading on other lines.

55. To the extent that transmission system costs should appropriately be apportioned among long term firm transmission users, unloading should not be of

particular relevance because any additional capacity created by the unloading does not eliminate the need to recover the embedded transmission costs.

56. The unloading attributable to a particular wheeling transaction does not necessarily provide any long term benefit because dynamic changes on the system can rapidly transform an unloading effect into a loading effect.

57. As facilities must be planned and constructed in recognition that a transaction which may in one circumstance cause a reduction in line loading may in another circumstance overload a line due to the dynamism of the transmission system, cost responsibility should be assigned to all usage regardless of whether line loadings are increased or decreased by the usage.

58. Vector absolute megawatt mile totals can add up to far more than the capacity of a line, but so long as all usage in the system is similarly measured, the ratio of individual usage to total system usage should provide an accurate depiction of relative usage and a reasonable basis for allocating transmission system costs among long term firm users of the system.

59. PUB's usage of the LCRA and MEC transmission systems should be calculated using vector absolute megawatt mile totals.

60. PUB's usage of the LCRA transmission system totals 2964 vector absolute megawatt miles.

61. PUB's usage of the MEC transmission system, based upon MEC's extrapolation methodology, totals 15.6 vector absolute megawatt miles.

62. MEC did not introduce into evidence an accurate quantification of usage specific to its facilities as opposed to aggregate STEC/MEC facilities.

63. The impact on MEC's transmission system attributable to the PUB/Oklaunion transaction is de minimis and MEC consequently is not entitled to compensation from PUB.

64. The issue of whether future expansion of the MEC transmission system may cause the Oklaunion/PUB transaction to have a greater impact on that system is beyond the appropriate scope of this docket.

65. P.U.C. SUBST. R. 23.67 provides for the calculation of total system megawatt mileage based upon the theoretical capacity of a transmission system.

66. The use of total system capacity in the calculation of the megawatt mile unit rate causes the occurrence of cost subsidies because usage is never equal to theoretical system capacity, due to the need to maintain circuit redundancy and unused capacity necessary for system reliability under adverse circumstances.

67. If the megawatt mile unit rate is calculated using system capacity as the divisor, the cost of unused capacity falls upon the native system customer as a consequence of the incomplete allocation of total transmission system costs.

68. An arithmetically meaningless result is achieved in calculating wheeling charges under a megawatt mile methodology unless total system megawatt mileage is computed in exactly the same manner as the megawatt mile usage of the wheeling customer.

69. The long term life-of-the-plant nature of wheeling transactions involving remote generation, and the lack of interruptibility of that power, together sufficiently distinguish remote generation wheeling transactions from those transactions covered by P.U.C. SUBST. R. 23.67 to warrant the conclusion that the Commission's policy decision to use a capacity based measurement of system megawatt mileage for purposes of that rule is not appropriately applicable by analogy to remote generation.

70. Public policy should not favor subsidization by LCRA's native system customers of the true costs of long term firm transmission service used to support another utility's remote generation.

71. Total system megawatt mileage should be based upon total system usage as opposed to total capacity.

72. There is no distinction in the quality of the usage imposed upon LCRA's system by PUB and CP&L with respect to the wheeling of power from Oklaunion.

73. The megawatt mile usage of LCRA's system attributable to CP&L's ownership interest in Oklaunion must be included within the system megawatt mile total for purposes of calculating a dollar per megawatt mile wheeling rate.

74. LCRA understated total system usage by omitting from total usage the relative usage of the LCRA system attributable to inadvertent flows from other ERCOT utilities.

75. Netting LCRA's inadvertent flows against those imposed by other ERCOT utilities is improper because LCRA's impacts upon those utilities are attributable entirely to LCRA's use of its generating units to meet its native system load. LCRA's inadvertent flows are not caused by off-system customers.

76. In calculating total system megawatt mileage, the inadvertent flows attributable to use of LCRA's transmission system should not be offset by the inadvertent flows on other utility systems attributable to LCRA.

77. The sum of each individual use of the transmission system will produce a larger number than if those individual uses are aggregated into groups and the group uses are then summed, because reciprocal impacts attributable to the component transactions will be cancelled out and will not be reflected in the statement of total megawatt mile usage.

78. Although LCRA performed base and change simulations for specific off-system users, LCRA did not perform base and change simulations for the purpose of measuring the megawatt mile usage attributable to each of LCRA's full requirements customers, or even to the group as a whole.

79. In calculating total system mileage, LCRA improperly permitted all reciprocal megawatt mile effects to be netted out in the calculation of the megawatt miles attributable to all long term firm usage on the LCRA system, with the exception of the usage attributable to four specific off-system transactions, thus shifting a disproportionate share of embedded transmission facility costs to those specific off-system transactions.

80. Equitable application of LCRA's vector absolute megawatt mile methodology requires rejection of LCRA's surrogate measure of native system usage in favor of measurements derived from base and change simulations.

81. LCRA should run base and change simultions reflecting the impact of serving each of LCRA's 90 delivery points from LCRA's collective generation, since LCRA's usage is comprised of multiple load areas and multiple sources of generation, and no convincing rationale has been advanced for netting the effects of all native system uses of LCRA's transmission facilities.

82. To derive total system usage, the sum of the megawatt mile impacts attributable to each of LCRA's delivery points should be added to the megawatt miles attributable to the non-netted effect of inadvertent flows on the system and the megawatt miles attributable to the San Miguel/BEPC transfer, the Texas Gulf Cogen/TUEC transfer, the Inter-North/TUEC transfer, the Oklaunion/CP&L transfer and the Oklaunion/PUB transfer.

83. Should it not prove feasible to run base and change simulations for each LCRA delivery point, all long term firm use of the LCRA system should be divided into two separate groups comprised of all native system uses, and all non-native system uses, and the uses within each group should be treated as one transaction for purposes of running base and change simulations. The transmission revenue requirement attributable to long term firm users should then be allocated between the two groups based on the ratio of each group's usage to the sum of the net usage attributable to the two groups. A dollar per megawatt mile rate

should then be calculated for the non-native group by dividing the group revenue requirement by the sum of the non-netted group megawatt mile uses.

84. The data necessary to calculate total system miles in the manner specified in either Finding of Fact No. 82 or Finding of Fact No. 83 is not contained in the evidentiary record and is unavailable until such time as the necessary base and change computer simulations are run.

85. The only contested aspect of the calculation of the firm transmission revenue requirement concerns the inclusion or exclusion of $124,062 in miscellaneous electric revenues from the calculation.

86. The staff's recommendation that $124,062 in miscellaneous electric revenues be included in the calculation of the firm transmission revenue requirement as a revenue requirement offset should be adopted.

87. The LCRA firm transmission revenue requirement to be utilized in this proceeding for purposes of calculating a unit rate for wheeling is $15,176,581.

88. The revenue requirement found in this docket should be utilized pending final action on LCRA's rate application currently pending in Docket No. 8032.

89. The staff's alternative proposals to calculate total allocable costs based upon long run incremental cost concepts should be rejected because that approach was not sufficiently developed during the hearing and no party advanced those proposals as its primary recommendation.

90. LCRA has failed to meet its burden of proof with respect to its proposed treatment of line losses.

91. Due to the absence of any better alternative, the methodology for calculation of line losses set forth in P.U.C. SUBST. R. 23.66(d)(5)(F) should be adopted for use in connection with the Oklaunion/PUB transaction.

92. This proceeding should be remanded to the examiner after all methodological issues have been resolved by the Commission, for the limited purposes of admission into the evidentiary record of all data necessary to the calculation of the specific wheeling rate to be applied to PUB, calculation of that rate, and incorporation of the resultant rate as well as the recommendations made herein into the text of the proposed LCRA tariff applicable to the Oklaunion/PUB transaction.

93. The Commission should initiate a rulemaking proceeding upon conclusion of this docket for the purpose of formulating a uniform statewide policy with respect to the wheeling of power from remotely sited generation facilities.

94. Should a remote generation wheeling rule be adopted, the wheeling rates established herein should at that time be superseded on a prospective basis by revised rates calculated in accordance wuth the wheeling methodology embodied in that substantive rule.

95. Due to the limited scope of this docket, no precedential value should be assigned this docket in future proceedings.

B. Conclusions of Law

1. LCRA and MEC are public utilities as defined in Section 3(c)(1) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988). PUB is a retail public utility as defined in PURA Section 49.

2. The Commission has jurisdiction over the matters raised in this proceeding pursuant to PURA Sections 16(a), 17(e) and 37.

3. Notice of the pendency of this proceeding was issued by PUB in full compliance with the notice requirements established by the examiner under authority of P.U.C. PROC. R. 21.25(a)(3).

4. P.U.C. SUBST. R. 23.66 and 23.67 are not applicable to remote generation wheeling transactions.

5. LCRA has the burden of proof in this proceeding and consequently, it is entitled to choose and advocate the theory under which it believes it is entitled to compensation from PUB, and such must control over the verbiage utilized in the label appended by the Commission to this docket.

6. The dividing line between permissible and impermissible discrimination by a public utility is generally that drawn by the "rule of reasonableness". Mere inequality is not in itself unlawful discrimination. Unequal treatment is permissible so long as there exists a substantial and reasonable ground of distinction between the favored and disfavored individuals or classes.

7. The unequal treatment which LCRA proposes to afford PUB's remote generation as opposed to the inadvertent flows of ERCOT utilities does not constitute unlawful discrimination because a substantial and reasonable ground of distinction exists to support that unequal treatment.

8. Utility practices embodied in the <u>ERCOT Opertaing Guides</u> are not legally binding upon this Commission.

9. The existence or non-existence of an obligation to compensate a utility for the use made of its transmission facilities as a consequence of a wheeling transaction is not governed by Texas range law, water law, lateral support law, law pertaining to improvements of easements or the "Texas party wall" doctrine.

10. LCRA is entitled to compensation from PUB for the use made of LCRA's transmission facilities by PUB in utilizing Oklaunion generation to serve PUB's load requirements. No compensation is owed to MEC by PUB.

11. To the extent recognized by the final Order herein, LCRA has met its burden of pursuasion.

12. The wheeling rates which result from application of the methodologies proposed herein are not unreasonably preferential, prejudicial or discriminatory, but are sufficient and equitable as required by PURA Section 38.

Respectfully submitted,

Mark W. Smith

MARK W. SMITH
ADMINISTRATIVE LAW JUDGE

APPROVED on this the 21st day of March 1988.

Phillip A. Holder

PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

nsh

DOCKET NO. 6995

PETITION OF LOWER COLORADO RIVER AUTHORITY ET AL. FOR DETERMINATION OF WHEELING IMPACT OF THE TRANSMISSION OF BULK POWER FROM OKLAUNION UNIT NO. 1 TO THE PUBLIC UTILITIES BOARD OF THE CITY OF BROWNSVILLE	§	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that, after notice was provided to the public and interested persons, the application in this case was processed by an administrative law judge in accordance with Commission rules and all applicable statutes. An Examiner's Report containing Findings of Fact and Conclusions of Law was submitted, which report, as subsequently amended by the administrative law judge, is hereby ADOPTED and made a part hereof. The Commission further issues the following Order:

1. The various requests for relief urged by the parties are GRANTED to the extent recommended in the Examiner's Report attached hereto.

2. This docket is REMANDED for the limited purposes of receiving into evidence all data necessary to the calculation of the specific wheeling rate which results from application of the methodology adopted by this Order, calculation of that rate, and incorporation of that rate into a tariff fully consistent with the terms of this Order.

3. All motions, applications and requests for specific findings of fact and conclusions of law, if not expressly granted herein, are denied for want of merit.

SIGNED AT AUSTIN, TEXAS on this the 20th day of May 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Dennis L. Thomas
DENNIS L. THOMAS

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: Marta Greytok
MARTA GREYTOK

ATTEST:

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

nsh

DOCKET NO. 6995

PETITION OF LOWER COLORADO RIVER AUTHORITY ET AL. FOR DETERMINATION OF WHEELING IMPACT OF THE TRANSMISSION OF BULK POWER FROM OKLAUNION UNIT NO. 1 TO THE PUBLIC UTILITY BOARD OF THE CITY OF BROWNSVILLE	§ § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER ON REHEARING

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas considered Medina Electric Cooperative, Inc.'s motion for rehearing in this docket. Based upon consideration of the arguments raised in that motion, the Commission issues the following Order:

1. Medina Electric Cooperative, Inc.'s motion for rehearing is GRANTED.

2. Finding of Fact Nos. 62 and 63 of the Examiner's Report are DELETED.

3. The scope of the remand proceeding in this docket is EXPANDED to include the development and receipt into evidence of all data necessary to the calculation of a specific Medina Electric Cooperative, Inc. wheeling rate which results from application of the methodology adopted by the Commission's May 20, 1988 order of remand, calculation of that rate, and incorporation of that rate into a Medina Electric Cooperative, Inc.'s tariff.

SIGNED AT AUSTIN, TEXAS on this the 5th day of July 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: Marta Greytak
MARTA GREYTOK

ATTEST:
Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

nsh

DOCKET NO. 6995

PETITION OF LOWER COLORADO RIVER AUTHORITY ET AL. FOR DETERMINATION OF WHEELING IMPACT OF THE TRANSMISSION OF BULK POWER FROM OKLAUNION UNIT NO. 1 TO THE PUBLIC UTILITIES BOARD OF THE CITY OF BROWNSVILLE	§ § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

SUPPLEMENTAL EXAMINER'S REPORT

I. Procedural History

An Examiner's Report was issued in the above captioned docket on March 21, 1988 by the undersigned examiner. That report was adopted by the Commission by written order dated May 20, 1988. Pursuant to the recommendations contained in that report, the Commission remanded the proceeding to the examiner for the limited purposes of obtaining the data necessary to calculate a wheeling rate using the methodology recommended in the Examiner's Report, calculation of that rate, and incorporation of that rate into a Lower Colorado River Authority (LCRA) tariff applicable to the Public Utilities Board of the City of Brownsville (PUB).

A post-hearing conference was convened on May 31, 1988. The parties agreed at the conference that they would work together to develop the software and perform the computerized load flow simulations necessary to calculate wheeling rates using the methodology adopted by the Commission.

On May 31, 1988, Medina Electric Cooperative, Inc. (MEC) filed a motion for rehearing, urging that the Commission's May 20, 1988 order be modified to permit MEC to charge PUB for wheeling impacts associated with PUB's transfer of bulk power from Oklaunion Unit No. 1 to Brownsville, despite the de minimis nature of those impacts on MEC's system. On July 5, 1988, the Commission granted MEC's motion and issued an order expanding the scope of the remand proceeding to include development of an MEC wheeling rate and tariff applicable to PUB.

A second post-hearing conference was convened on September 16, 1988 at which LCRA, PUB and the Commission staff announced that they had reached agreement on the LCRA wheeling rate and associated tariff. MEC did not make an appearance at the conference. A written stipulation was subsequently filed on November 14, 1988 by LCRA, PUB and the Commission's general counsel.

On October 21, 1988, counsel for MEC filed a letter with the Commission indicating that MEC had participated with LCRA and PUB in the wheeling calculations and that: 1) the calculations reflect no present impact on MEC's transmission system; 2) MEC agrees that wheeling payments by PUB are not warranted; and 3) MEC does not desire to participate further in the remand proceeding.

II. Discussion and Opinion

The intent of the Commission's remand order in this proceeding was to provide a vehicle by which the examiner's recommended vector-absolute megawatt-mile (VAMM) methodology for calculating wheeling rates applicable to the transfer of bulk power from Oklaunion Unit No. 1 to the City of Brownsville could be translated into specific wheeling tariffs for LCRA and MEC. Attachment No. 1 to this report is a written stipulation entered into by LCRA, PUB and the Commission's general counsel reflecting agreement that application of the VAMM methodology to the Oklaunion/Brownsville transaction results in an annual wheeling rate chargeable by LCRA to PUB of $48.45 per megawatt-mile. Attachment No. 2 to this report is a letter from counsel for MEC which reflects MEC's decision not to implement a wheeling tariff applicable to the Oklaunion/Brownsville transaction, based upon the lack of any significant impact by that transaction upon MEC's transmission system.

The proposed LCRA tariff is wholly consistent with the recommendations contained in the Examiner's Report. As recommended by the examiner, the tariff is applicable solely to the Oklaunion/Brownsville transaction and does not purport to establish rates for any other wheeling transaction. Additionally, the parties agree that the stipulated annual wheeling rate of $48.45 per megawatt-mile has been calculated in a manner consistent with the methodology recommended by the examiner and adopted by the Commission. Further, the megawatt-mile total specified in the proposed tariff equals the megawatt-mile total found by the examiner in Finding of Fact No. 60 of the original Examiner's Report. Finally, under the proposed tariff line losses are treated in the manner specified by Finding of Fact No. 91 of the original Examiner's Report.

The stipulation provides that the agreed wheeling rate be retroactively effective from and after the December 24, 1986 commercial operation date of Oklaunion Unit No. 1, and that the rate remain in effect until changed by subsequent order of the Commission. The examiner fully endorses the retroactive applicability of the proposed wheeling rate, due to the considerable length of time it has taken to bring this proceeding to conclusion.

The examiner recommends that the Commission accept the stipulation of the parties and approve the proposed LCRA wheeling tariff as filed on November 3, 1988. Further, the examiner renews the recommendation in the original Examiner's Report that, upon conclusion of this proceeding, the Commission initiate a rulemaking proceeding for the purpose of formulating a uniform statewide policy with respect to the wheeling of power from remotely sited generation facilities.

III. Findings of Fact and Conclusions of Law

The examiner further recommends adoption of the following findings of fact and conclusions of law:

A. Findings of Fact

1. This remand proceeding was initiated on May 20, 1988 by written order of the Commission.

2. The purpose of the remand proceeding is to develop specific wheeling tariffs for LCRA and MEC applicable to the transfer of bulk power from Oklaunion Unit No. 1 to PUB, using the VAMM methodology adopted by the Commission on May 20, 1988.

3. MEC has declined to propose or implement a tariff applicable to the Oklaunion/Brownsville transaction, based upon its determination that the transaction has no present impact on MEC's transmission system.

4. LCRA, PUB and the Commission's general counsel filed a written stipulation on November 14, 1988, reflecting agreement as to the rates, terms, and conditions to be included in an LCRA tariff applicable to the Oklaunion/Brownsville transaction.

5. The LCRA tariff proposed by the parties is wholly consistent with the recommendations contained in the Examiner's Report adopted by the Commission on May 20, 1988.

6. The proposed LCRA tariff is applicable solely to the Oklaunion/Brownsville transaction and does not purport to establish rates for any other wheeling transaction.

7. The stipulated annual wheeling rate of $48.45 per megawatt-mile is calculated in a manner consistent with the VAMM methodology adopted by the Commission on May 20, 1988.

8. The megawatt-mile total specified in the proposed tariff equals the megawatt-mile total specified in Finding of Fact No. 60 of the original Examiner's Report in this docket.

9. The proposed tariff treats line losses in the manner specified by Finding of Fact No. 91 of the original Examiner's Report.

10. The proposed wheeling rate should be retroactively effective from and after the December 24, 1986 commercial operation date of Oklaunion Unit No. 1, and should remain in effect until changed by subsequent order of the Commission, as stipulated by the parties.

11. The proposed LCRA tariff, which was filed on November 3, 1988 as an attachment to the parties' stipulation, should be approved without modification.

12. A rulemaking proceeding would be an appropriate mechanism for formulating a uniform statewide policy with respect to the wheeling of power from remotely sited generation facilities.

B. Conclusions of Law

1. LCRA and MEC are public utilities as defined in Section 3(c)(1) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1988). PUB is a retail public utility as defined in PURA Section 49.

2. The Commission has jurisdiction over the matters raised in this proceeding pursuant to PURA Sections 16(a), 17(e) and 37.

3. The wheeling rates and tariff terms and conditions embodied in the stipulated LCRA wheeling tariff applicable to the Oklaunion/Brownsville

transaction are just and reasonable and otherwise comply with the ratemaking mandates of Article VI of PURA and should be approved.

Respectfully submitted,

Mark W. Smith

MARK W. SMITH
ADMINISTRATIVE LAW JUDGE

APPROVED on this the 29th day of November 1988.

Phillip A. Holder

PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

nsh

BEFORE THE
PUBLIC UTILITY COMMISSION OF TEXAS

PETITION OF LOWER COLORADO RIVER AUTHORITY ET AL. FOR DETERMINATION OF WHEELING CHARGE FOR THE TRANSMISSION OF BULK POWER FROM OKLAUNION UNIT NO. 1 TO THE PUBLIC UTILITIES BOARD OF THE CITY OF BROWNSVILLE	§ § § § § § § §	DOCKET NO. 6995

STIPULATION

WHEREAS the Examiner's Report in this docket dated March 21, 1988 was presented to and approved by the Public Utility Commission; and

WHEREAS pursuant to the Examiner's recommendation, the Public Utility Commission remanded the matter to the Examiner for the calculation of a specific wheeling rate; and

WHEREAS the Public Utilities Board of the City of Brownsville and the Lower Colorado River Authority have conducted additional studies consistent with the methodology described in the Examiner's Report, and have participated in continuing discussions concerning the results of those studies; and

WHEREAS the General Counsel has continued to monitor the progress of discussions between the parties; and

WHEREAS the parties have reached agreement as to a specific wheeling rate to be adopted in this cause:

NOW THEREFORE the Public Utilities Board of the City of Brownsville, the Lower Colorado River Authority, and the General Counsel of the Public Utility Commission of Texas agree as follows.

1. The Public Utility Commission of Texas should approve an annual rate of $48.45 per megawatt-mile for the transmission of power over the Lower Colorado River Authority transmission system from Oklaunion Unit No. 1 to the City of Brownsville. The parties agree that the rate stipulated to is calculated in a manner consistent with the methodology approved by the Public Utility Commission in adopting the Examiner's Report referred to above.

2. The proposed tariff sheet, a copy of which is attached to the Stipulation as Appendix A, should be approved by the Commission.

3. The wheeling rate to be adopted in this proceeding should be retroactively effective from and after the date of commercial operation of Oklaunion Unit No. 1, on December 24, 1986 and should remain in effect until changed by subsequent order of the Public Utility Commission.

4. This Stipulation represents a compromise by the parties to this agreement and should be viewed strictly as the product of compromise and settlement for the purposes and under the conditions set forth herein.

WHEREFORE, PREMISES CONSIDERED, the parties whose authorized signatures appear below urge the Commission to adopt the rate set forth above and to approve the tariff sheet attached hereto.

Respectfully submitted,

PUBLIC UTILITIES BOARD OF
THE CITY OF BROWNSVILLE

By Bob Kahn
Bob Kahn - 11074230

LOWER COLORADO RIVER AUTHORITY

By Lawrence S. Smith
Lawrence S. Smith - 18639000

GENERAL COUNSEL, PUBLIC UTILITY
COMMISSION OF TEXAS

By Paula Mueller

LOWER COLORADO RIVER AUTHORITY
P. O. Box 220
Austin, TX 78767

ELECTRICAL TARIFF

Section No.__________ Revision No.__________ Sheet No. ______
Section Title Rate Schedule Replacing Revision No.__________ Sheet No.______
Effective______________________
Month Day Year

432 Rate Schedule WS
Form No. 344

WHEELING SERVICE
FOR
TRANSMISSION OF FIRM POWER
FROM OKLAUNION TO
PUBLIC UTILITIES BOARD OF THE CITY OF BROWNSVILLE

Applicable:

For wheeling service for Public Utilities Board of the City of Brownsville (PUB) transfer of 68 MW of capacity from Oklaunion Unit No. 1 to PUB's certified service area.

Available:

To PUB for wheeling services with LCRA with respect to Oklaunion Unit 1-68 MW of capacity.

Rate

Facilities Charge:

$ 4.0375 per MW mile per month.

The billing MW-miles shall be 2964 MW-miles.

Losses:

Increases or decreases in losses incurred by LCRA due to the PUB transfer shall be determined from the scheduled transfer used in conjunction with loss matrices produced by the Electric Reliability Council of Texas Engineering Subcommittee or upon average LCRA system losses for increased losses at the option of PUB.

Increases or decreases in losses shall be repaid in kind at the time of the PUB transfer if practical or if such repayment is not practical, accumulated in peak and off-peak accounts for later payback. If both LCRA and PUB agree payments and credits for losses may be in cash.

Special Conditions:

Billing.

(a) Due Date. The due date of the bill for utility service shall not be less than 16 days after issuance. A bill for utility service is delinquent if not received at the LCRA or at LCRA's authorized payment agency by the due date. The postmark, if any, on the envelope of the bill, or an issuance date on the bill, if there is no postmark on the envelope, shall constitute proof of the date of issuance. If the due date falls on a holiday or weekend, the due date for payment purposes shall be the next work day after the due date.

(b) Penalty on delinquent bills. A one-time penalty not to exceed 5.0% will be made on delinquent bills. The 5.0% penalty on delinquent bills will not be applied to any balance to which the penalty was applied in a previous billing.

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October 20, 1988

Mr. Mark Smith
Administrative Law Judge
Public Utility Commission of Texas
7800 Shoal Creek Blvd., Suite 400N
Austin, Texas 78757

Re: Docket 6995; Petition of Lower Colorado River Authority et al. for Determination of Wheeling Impact of the Transmission of Bulk Power from Oklaunion Unit #1

Dear Judge Smith:

Pursuant to contacts I have had with counsel for both Lower Colorado River Authority ("LCRA") and Public Utility Board of Brownsville ("PUB"), subsequent to the Post-Hearing Conference held on October 11, it is my understanding that you had expressed on interest in ascertaining Medina Electric Cooperative, Inc.'s ("Medina") position on further involvement in the above referenced docket. Medina has taken part in the development of the LCRA wheeling calculation and is satisfied that, at the present time, Medina is not impacted sufficiently to warrant a wheeling payment from PUB. In addition, PUB has graciously offered to run their program calculation for Medina at costs; however, given the basic similarities between the methods as they potentially impact Medina, Medina believes the result would be the same. Therefore, Medina has declined PUB's invitation.

Given that Medina is in basic accord with the LCRA calculation methodology, and that calculation indicates no present impact on Medina's transmission system, Medina does not expect to participate further in this docket. In the event the ALJ or Commission should decide to alter some part of the calculation, thereby giving rise to the possibility Medina might be then be impacted, Medina requests that it be allowed to remain as a party in the docket. However, as noted above, Medina does not presently expect compensation if the

LCRA calculation methodology, as developed to date by LCRA, is finally approved by the Commission.

I trust that this clarifies Medina's position on this matter. A copy of this letter has been sent to all parties of record on this docket. Thank you for your kind attention to this matter.

Very truly yours,

NAMAN, HOWELL, SMITH & LEE

BY: Allen H. King

Allen H. King

AHK/rh
8710206:13d1
cc: All parties of record

DOCKET NO. 6995

PETITION OF LOWER COLORADO RIVER AUTHORITY ET AL. FOR DETERMINATION OF WHEELING IMPACT OF THE TRANSMISSION OF BULK POWER FROM OKLAUNION UNIT NO. 1 TO THE PUBLIC UTILITIES BOARD OF THE CITY OF BROWNSVILLE	§ § § § § §	PUBLIC UTILITY COMMISSION OF TEXAS

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the above-styled matter was processed in accordance with applicable statutes by an administrative law judge who prepared and filed a report, containing findings of fact and conclusions of law, which was adopted by the Commission on May 20, 1988, as well as a supplemental report containing supplemental findings of fact and conclusions of law, which Supplemental Examiner's Report is ADOPTED and made a part hereof. The Commission further issues the following Order:

[3] 1. The LCRA tariff filed on November 3, 1988 and captioned "Wheeling Service for Transmission of Firm Power from Oklaunion to Public Utilities Board of the City of Brownsville" is APPROVED effective the date of this Order.

[4] 2. The Commission staff SHALL undertake a review of P.U.C. SUBST. R. 23.67 to consider inclusion of remote generation within the ambit of the rule, and such other related issues as may be appropriate, and shall thereafter propose such rule amendments as are appropriate.

3. This Order is deemed effective on the day of signing.

4. All motions, applications and requests for entry of specific findings of fact and conclusions of law, and any other requests

for relief, general or specific, if not expressly granted herein are DENIED for want of merit.

SIGNED AT AUSTIN, TEXAS on this the 13th day of December 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: Jo Campbell
JO CAMPBELL

SIGNED: William B. Cassin
WILLIAM B. CASSIN

ATTEST

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

nsh

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES § **DOCKET NO. 8032**

September 22, 1988

Examiner's Report adopted with the exception of Section VI and certain findings of fact and conclusions of law, all relating to cost allocation and rate design. The revenue requirement issues were resolved by stipulation of all parties. Motions for rehearing overruled by operation of law on November 4, 1988.

[1] RATEMAKING--COST ALLOCATION--ELECTRIC--COST ALLOCATION METHODOLOGIES

The complexity and volatility of the Probability of Dispatch (POD) methodology makes it inappropriate for adoption. (p. 1695)

[2] RATEMAKING--COST ALLOCATION--ELECTRIC--COST ALLOCATION METHODOLOGIES

Absent evidence of material change in condition or factual circumstances, there is no support for changing a utility's current cost allocation methodology. (p. 1696)

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DOCKET NO. 8032

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

EXAMINER'S REPORT

I. Procedural History

On March 14, 1988, the Lower Colorado River Authority (LCRA) filed with the Commission a statement of intent and an application to increase its retail and wholesale rates in the unincorporated areas which it serves. No appeals from city ratemaking ordinances have been taken. Based on a test year ending September 30, 1987, LCRA was seeking to increase its system-wide revenues by $37,499,136 annually, an increase of 16.06 percent over test year revenues. The proposed increase would affect all customer classes.

On March 17, 1988, pursuant to Section 43(d) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987), the implementation of the proposed rates was suspended for 150 days beyond their otherwise effective date of April 18, 1988, until September 15, 1988, or until superseding order of the Commission. On June 24, 1988, LCRA agreed to extend the effective date of its rates for every day that the hearing in this docket was not convened, beginning with June 23, 1988. The days of extension included June 24th through June 30th, resulting in a new effective date of April 25, 1988. The total number of days of hearing was 16; therefore, pursuant to Section 43(d) of PURA, the 150-day suspension period was extended two additional days, resulting in a suspension period that extends until September 24, 1988, or superseding order of the Commission.

Public notice of the application was published once a week for four consecutive weeks, in newspapers of general circulation in the counties affected by the proposed change, prior to the original effective date of April 18, 1988. Copies of the application, consisting of the statement of intent and rate filing package, were delivered to all of LCRA's wholesale customers, and individual notice of the application, as required by P.U.C. PROC. R. 21.22(b), was mailed to all of LCRA's customers and to the County Commissioner's Court of each county which will be affected by the proposed rate change, on April 21, 1988.

A prehearing conference was held on March 30, 1988, at which time motions to intervene by the following entities were granted: Guadalupe Valley Electric Cooperative (GVEC); City of San Marcos and Electric Utility Board; Association of Wholesale Customers (AWC); Bluebonnet Electric Cooperative, Inc., Central Texas Electric Cooperative, Inc., Bandera Electric Cooperative, Inc., and Kimble Electric Cooperative, Inc. (BEC et al.); and Structural Metals, Inc. (SMI). At the prehearing conference, the examiner established general guidelines and procedures leading up to the hearing on the merits, including deadlines for motions to intervene, discovery procedures and deadlines, and requirements for prefiling of evidence.

On April 8, 1988, the petition of Texas Industrial Energy Consumers (TIEC) for leave for intervene was granted. TIEC represents, in this docket, Mobil Oil Co., Phillips Petroleum Co., and Quanex Corp. On April 15, 1988, the petition of City of Kerrville and its agent, Kerrville Public Utility board, to intervene was granted. On April 20, 1988, the motion to intervene of Pedernales Electric Cooperative, Inc. (PEC) was granted. On April 25, 1988, the Office of Public Utility Counsel's (OPC) motion to intervene was granted.

The hearing on the merits was convened as originally scheduled on June 20, 1988. On the first day of the hearing the parties advised the examiner that they were interested in negotiating toward possible settlement and wished to recess for that purpose. A motion requesting the recess had been filed by LCRA and was granted by the examiner. During the first day of hearing, LCRA agreed that each day that the hearing was convened (in order to obtain a status report on the negotiations) would be considered a day of hearing. The hearing was convened each day from June 20-23, 1988, for purposes of obtaining a status report on the negotiations. The examiner was advised on June 23, 1988, that the parties had reached a stipulation, or agreement in principle, concerning the revenue requirement phase of the hearing, and were in the process of drafting a written stipulation to be submitted into evidence. The parties requested that the rate design phase of the hearing begin on July 5, 1988. In consideration of the delay attendant to beginning the hearing on rate design on July 5, 1988, LCRA agreed to extend its effective date day for day for each day the hearing was not convened. At the June 23, 1988 hearing, counsel for LCRA advised the examiner that a written stipulation signed by all parties would be ready for filing by June 28, 1988 and that LCRA was preparing evidence in support of the stipulation, which the examiner ordered to be filed on July 1, 1988. As part of the stipulation, all parties' prefiled testimony concerning revenue requirement was to be admitted on July 5, 1988 without objection from any other party, and with explicit waiver of rights to cross-examination of each witness. The examiner was advised by counsel for LCRA that at least one intervenor requested that certain of LCRA's revenue requirement witnesses be made available during the rate design phase of the hearing for cross-examination on revenue requirement issues affecting rate design, and LCRA had agreed to the request.

The hearing was reconvened on July 1, 1988, at which time several procedural matters were taken up, including rulings on motions to strike prefiled testimony, motions to align and motions to establish the order of cross-examination. Due to slight dissimilarities in the positions of the parties, the examiner declined to align or group parties, but did establish an order of cross-examination that required parties whose cases were in basic agreement to cross-examine witnesses prior to the cross-examination of adverse parties. Two sets of intervenors were grouped due to their representation by the same counsel. The first group was SMI and TIEC. The other group contained the Cities of Kerrville and San Marcos.

At the July 1, 1988 hearing, the examiner advised LCRA that, after reviewing the stipulation evidence which had been filed on June 29, 1988, she found that it appeared to be insufficient to support the stipulated revenue requirement. She explained that it was necessary to have evidence to show how the numbers had been determined and that the evidence filed consisted of conclusory statements unsupported by facts, or with references in most instances to numerous pages of testimony or other parties' witnesses which was often conflicting, inconsistent or unrelated and from which it was impossible to discern a path of reason to the stipulated facts. The examiner advised LCRA that it should redraft the stipulation testimony in order to satisfy these concerns. Revised stipulation testimony was filed on July 13, 1988, and admitted into evidence without objection. The hearing on the merits concerning cost allocation and rate design was held on eleven days between July 5 and July 19, 1988.

At the close of the hearing there remained one outstanding evidentiary dispute concerning the admissibility of portions of depositions of LCRA's witnesses. The examiner set up a schedule for the parties to urge the admission of certain previously determined excerpts through motions to be filed by noon on July 21, 1988 with objections thereto to be filed by noon on July 25, 1988 and responses to the objections by noon on July 27, 1988. A ruling on those offers was made in Examiner's Order No. 11, issued on August 17, 1988.

The parties were ordered to file closing briefs by 4:00 p.m. on August 1, 1988, and all parties except OPC did so. Reply briefs were due by 4:00 p.m. August 8, 1988 and were received from all parties except the General Counsel.

LCRA was represented at the hearing by Martha Terry, attorney-at-law, and presented evidence through the following witnesses:

William Freeman	Walter Reid
Milton Lee	Stephen Bartley
Dale Tucker	James Hamann
Robert Lee Hutchins	Vickie Corinne Langston
Angela Taylor	

PEC was represented by Casey Wren, attorney-at-law, and presented the testimony of William Avera and Gary Goble.

BEC et al. was represented by Earnest Casstevens, attorney-at-law, and presented the testimony of Ellen Blumenthal and Thomas Foreman.

AWC was represented by Sandra Neisser Boone and Howard Fisher, attorneys-at-law, and presented the testimony of Neil Eisner, Carl Stover and George Rogers.

GVEC was represented by Richard Balough, attorney-at-law, and presented the testimony of Scott Norwood, Bertram Solomon, Marcus Pridgeon, and James Daniel.

SMI and TIEC were represented by Rex VanMiddlesworth, attorney-at-law, and presented the testimony of Raymond Stanley and Keith Hatfield.

The City of Kerrville did not present any testimony and was represented by Bob Kahn, attorney-at-law. Mr. Kahn also represented the City of San Marcos, and presented the testimony of William Belmont, Sheree Brown and Charles Ravell in the revenue requirements phase. The City of San Marcos did not submit any evidence in the cost allocation and rate design phase of the hearing.

OPC was represented by Presley R. Reed, Jr., Assistant Public Counsel, and presented the testimony of Carol Szerszen and Randy Allen in the first phase of the hearing but did not present any evidence in the cost allocation and rate design phase of the hearing.

The general counsel of the Commission was represented by Jess Totten and Paula Mueller, assistants general counsel. In the revenue requirement phase of the hearing the general counsel presented the evidence of Ruth Runyon, Keith Allen Rogas, Evan C. Rowe, Nat Treadway, Parviz Adib, Kentton Grant and Waldon Boecker. The general counsel did not present any evidence in the cost allocation and rate design phase of the hearing. AWC had filed a motion requesting the examiner to order the Commission staff to clarify whether the staff supported the position taken by the general counsel in its Statement of Position on Cost Allocation and Rate Design. The general counsel responded to the motion on July 8, 1988, claiming AWC had no business inquiring into the formulation of another party's case and asserting that its statement of position, in which it supported LCRA's methodology and resulting rates, protected the public interest. The examiner denied AWC's motion, finding it would be an unwarranted intrusion into the attorney-client relationship and that the general counsel's assertion regarding the public interest satisfied its statutory obligation.

Public comments were received from Tim Kelley on behalf of Mobile Exploration and Producing U. S., Inc.; Steven Palmitier on behalf of Quanex

Corporation-Bellville Tube Division; Sherry Gillen on behalf of the Lampasas Chamber of Commerce; and Clyde Sealy, on behalf of SMI.

II. Jurisdiction

LCRA is a public utility as defined in Section 3(c) of PURA. The Commission has jurisdiction over the application pursuant to Section 16(a), 17(e), 37 and 43(a) of PURA.

III. Description of LCRA

LCRA was created by the Texas legislature in 1934 as a conservation and reclamation district, including Blanco, Burnet, Llano, Travis, Bastrop, Fayette, Colorado, Wharton, San Saba and Matagorda counties. Tex. Rev. Civ. Stat. Ann. art. 8280-107, as amended by Senate Bill 115, Acts of the 64th Legislature, Regular Session, 1975, Chapter 74, Volume 1, of the General and Special Laws of Texas, 1975, and further amended by Senate Bill 194, Acts of the 68th Legislature, Regular Session, 1983, Chapter 484, Volume 2, Article IV, Section 1 and 2. This agency of the State of Texas was created to control, store, preserve and distribute the waters of the Colorado River and its tributaries within the boundaries of the district for irrigation, generation of electric energy and power and other useful purposes. LCRA provides electric power and energy under a wholesale rate tariff to thirty-one municipally owned systems and eleven rural electric cooperatives, primarily from its own facilities. LCRA also serves 75 retail customers. In 1986 and 1987, LCRA divested itself of three retail systems by transfers and sales to the Cities of San Marcos, San Saba and Kerrville. <u>See</u>, Docket No. 6929, <u>Application of LCRA for Transfer of Certificate Rights and Sale of Facilities to the City of San Marcos</u>, 12 P.U.C. 96 (1986); Docket No. 7025, <u>Application of LCRA for Authority to Transfer a Portion of its Facilities and Service Area to the City of San Saba,Texas</u>, (June 26, 1987); and Docket No. 7535, <u>Application of the LCRA for Transfer of Certificate Rights and Sale of Facilities to the City of Kerrville</u> (October 22, 1987). The LCRA owns or leases and operates electric generating, transmission and distribution facilities in all or portions of 28 counties.

The net dependable generating capacity of LCRA's plants in service at the end of the test year (September 30, 1987) totalled 1,836 megawatts (MW), which included 241,000 kW at six hydro-electric plants; 600,000 kW at the three Sam Gideon steam plants; 425,000 kW at the one Ferguson plant; and 570,000 kW representing LCRA's 50 percent interest in two of the Fayette Power Project units (FPP 1 and 2). The test year system fuel mix consisted of 56 percent natural gas, 31 percent coal, and 13 percent hydrogeneration.

LCRA's last rate increase was approved based upon a stipulation of all the parties on December 3, 1987. Docket No. 7512, Application of Lower Colorado River Authority for Authority to Change Rates. The rates approved in that docket were implemented after the end of the test year utilized in this docket, but the overall 12.5 percent increase in revenues is recognized in this docket by an adjustment to test year base rate revenues.

LCRA is proposing to increase its rates at this time due to the completion of Unit 3 at FPP. FPP 3 is the only one of the three Fayette units that is not jointly owned with the City of Austin. LCRA intends to file a third rate change application in March 1989 in order to phase in the remainder of the debt service cost attributable to FPP 3. LCRA received a certificate of convenience and necessity for FPP 3 in Docket Nos. 3838 and 3896, Application of LCRA and Application of Texland Electric Cooperative, Inc., (September 23, 1982). FPP 3 achieved commercial operation on April 29, 1988. It was constructed for use as a baseload unit and, although built as a lignite unit, is currently burning western coal. With the introduction of FPP 3 into the system, LCRA's fuel mix will be 35 percent natural gas, 60 percent coal, four percent hydroenergy and less than one percent lignite.

There are references throughout the rate filing package to LCRA's water and environmental operations. All accounting records of LCRA are maintained according to charts of accounts which are appropriate to the functions of the divisions, but which cannot be related directly to the FERC accounting system for electric utilities. Complete separation is maintained of revenues and expenses directly attributable to those operations.

LCRA has several objectives that it hopes to achieve through its proposed rate increase, including payment of its operation and maintenance (O&M)

expenses; payment of its principle and interest on debts; and the fulfillment of its debt resolutions to bond-holders.

IV. Revenue Requirement

A. Introduction

After several days of negotiation, all parties in this docket were able to reach a stipulation concerning the revenue requirement phase of the hearing. Their agreement is memorialized in a stipulation included herein as Attachment I. The evidence submitted in the revenue requirement phase of the hearing included all parties' prefiled testimony as well as the stipulation evidence prepared by LCRA witness Bartley. In reviewing the record, the examiner had some questions concerning the fuel expense, and additional evidence on this issue was submitted by Mr. Bartley and was admitted into evidence without objection. This section of the report will discuss those previously disputed issues upon which the parties were able to reach an agreement and which are reflected in the stipulation. It will also discuss issues that were raised in the prefiled testimony of the parties, which are not specifically addressed in the stipulation, but which are implicitly resolved in it.

As is reflected in Attachment I, the stipulation also covers one issue not directly related to revenue requirement. The parties agreed to the delivery point kilowatts (kW) and the delivery point kilowatt hours (kWh) that would be used as billing determinants under the final rate design methodology.

The parties agreed that a revenue increase of $21,494,302 was necessary and reasonable to permit LCRA to provide adequate and reliable electric service to its wholesale and retail customers, and would permit LCRA a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public. The following table sets out the unadjusted test-year revenue requirement and shows the revenue requirement as originally filed and as stipulated:

	LCRA UNADJUSTED TEST YEAR	LCRA ORIGINAL REQUEST	STIPULATION
Fuel	$105,140,733	$109,010,994	$108,506,160
Operations & Maintenance	60,382,921	63,508,630	58,808,630
Depreciation	18,157,395	17,068,426	17,068,426
Return	71,875,202	104,348,330	100,248,330
Revenue Requirement	$255,556,251	$293,936,380	$284,631,546
Other revenues	$ 58,980,766	$ 22,944,649	$ 29,644,649
Fuel revenues	99,209,006	109,010,994	108,506,160
Base Rate Revenues	$ 97,366,479	$161,980,737	$146,480,737
Overall Percent Increase		16.06%	9.21%

B. Fuel

1. Fuel Reconciliation

The parties stipulated to the final reconciliation of LCRA's over/underrecovery of fuel costs as presented by staff witnesses Boecker and Rowe. In Docket 7512, LCRA's over/underrecovery was reconciled for the period October 1983 through June 1987. In this case, the staff calculated LCRA's monthly over/underrecovery for the period covering July 1987 through March 1988. Mr. Rowe analyzed LCRA's management and procurement of fuel, and based upon the criteria enunciated in P.U.C. SUBST. R. 23.23(b)(2)(H) and the concept of reasonable and necessary operating expenses embodied in PURA Section 39(a), concluded that LCRA had prudently managed its procurement of fuel and had procured fuel at the lowest reasonable cost.

LCRA has been able to procure almost all of its natural gas supplies in the inexpensive spot market while maintaining full requirements contracts. During 1987, LCRA's cost of gas was the second-lowest of the state's major utilities. West Texas Utilities was lower due only to its long-term contract with Phillips for $0.22 per mmBtu gas. Mr. Rowe concluded that LCRA has been very successful in procuring low-cost gas.

During 1987, LCRA's average cost of coal was also the second-lowest of the state's major utilities, with only El Paso Electric having a lower coal cost. El Paso's lower cost is attributable to its mine-mouth plant and therefore the absence of coal transportation costs. LCRA was able to exploit the low-cost spot market and secure inexpensive coal fuel.

The cumulative underrecovery as of March 31, 1988, is $1,000,418, with a combined interest through March 31, 1988, of $21,616, yielding a total underrecovery of $1,022,034. Although the underrecovery was reconciled, it was not considered for recoupment from LCRA's customers because the amount was not material. This amount will be carried forward to be summed with future over- or underrecoveries. For the reasons set out above, the examiner finds this reconciliation to be reasonable and recommends its adoption.

2. Fuel expense during rate year

The parties have stipulated that LCRA's known and reasonably predictable fuel expense and fixed fuel factor revenues for the rate year will be $108,506,160. This is consistent with LCRA's original adjusted test-year kWh sales of 6,963,136,850, and the system fixed fuel factor, as recommended by the staff, of 1.584 cents per kWh.

LCRA utilizes a PROMOD computer model, a production costing program which simulates an economic dispatch of LCRA's generating unit to meet forecast load requirements, to project generation and fuel consumption for each of its fossil units. The PROMOD model projects four factors utilized by LCRA including: gigawatt hours (gWh) produced per plant per month; mmBtu of fuel consumed per plant per month; emergency power purchased per month in gWh; and the average heat rate per plant per month. LCRA projects that its rate-year purchased power expense will be $0 because its test-year purchased power expense, $2,932,890, is not recurring or predictable. LCRA did not predict any off-system sales or purchases during the rate year, but under the stipulation agreed to offset base rate revenues by $2 million attributable to off-system sales.

LCRA utilizes four types of fossil fuels, including natural gas, western coal, lignite from its Powell Bend Mine and #2 fuel oil. Based upon various contracts and current experience with short-term prices, LCRA projected rate-year fuel prices which staff witness Rowe found to be reasonable. Those prices are reflected on Attachment II.

Test-year sales are normalized so that any distortions in billing units that are the result of atypical conditions in the test-year will not distort the recovery of revenues in the rate-year. In this case, adjustments attributable to year-end customers and weather were made. LCRA proposed originally to adjust only three of its nine classes, including the small and large commercial, and seasonal residential classes. Staff witness Adib found LCRA's failure to adjust the remaining six classes unsupportable. He recommended an adjustment of 1.55 percent over test-year sales, as opposed to LCRA's proposal of 1.2 percent. Dr. Adib also found that there was a typographical error in Dr. Langston's weather adjustment calculation. Based upon econometric techniques, he recommended a 0.38 percent increase over year end customer adjusted kWh sales due to abnormal weather. LCRA had supplied to Dr. Adib a revision to test-year kWh sales, with which he agreed. That revision is shown in Exhibit C of the stipulation (Attachment I), and results in a total of 6,934,125,097 kWh.

As reflected above, the stipulated kWh sales were not utilized to determine the fuel and base rate revenues. According to Mr. Bartley's clarifying evidence, the revision was not made because the reduction in test-year adjusted kWh sales was less than one-half of one percent and the fixed fuel factor had already been calculated using projections of rate-year fuel costs and kWh sales as originally calculated. Utilizing the revised number would have had an insignificant effect on the overall percent increase. The movement of some of LCRA's customers up to the 138kv service, resulting in lower rates to those customers, and the fact that LCRA has not adjusted its loss multipliers to account for that customer shift, may result in a slight underrecovery of fuel costs. Although the fuel expense was not calculated using the stipulated revised kWh sales, the examiner finds the end result to be reasonable based upon the factors outlined above and the fact that the fuel expense is subject to review in the next reconciliation case and therefore recommends its acceptance.

C. <u>Operation and Maintenance (O&M) Expenses</u>

For purposes of settlement, LCRA agreed to reduce its requested level of O&M expense by $4.7 million. The adjustments to test-year O&M expenses are as

Test Year O&M		$60,382,921
Increases:		
Coal Handling	$6,915,711	
FPP 3 Railcar Lease	890,000*	
Lake Make Up	15,718*	
CP&L Power Bill	237,776	
Incentive Retirement Program	922,072*	
FPP 3 Payroll	7,495,300*	
TOTAL INCREASES		$16,476,577
Decreases:		
Water & Environmental	$8,061,293	
Allocated Water & Environmental	1,988,591	
Cooling Efficiency	1,583,638	
Franchise Requirements	258,839	
Retail O&M	3,225,617	
Purchased Power	2,932,890	
TOTAL DECREASES		($18,050,868)
PRO FORMA O&M		$58,808,630

* Reduced pursuant to stipulation.

This report will first address the four changes agreed to in the stipulation and then will address several other issues raised by the prefiled testimony, not specifically addressed in the stipulation but which formed the basis for the resulting total O&M expense.

1. FPP 3 Railcar lease expense

LCRA proposed in its original filing to increase its test-year O&M expense by $1,440,000 to reflect additional cost related to delivery of western coal to FPP 3. This included the cost of two trains, or 240 railcars. LCRA subsequently negotiated a contract with terms of $1 per day per car for the first four months of the rate-year. Based upon this updated lease cost LCRA projected that its railcar lease expense would total approximately $890,000, or $550,000 less than originally proposed. This is the sum agreed to by the parties. The examiner finds this expense reasonable.

2. Hydroenergy charge

LCRA originally proposed an expense of $3,215,718, for a hydroenergy charge which included $3,021,602 for a hydroelectric charge attributable to the benefit electric customers received from the stored water operations of LCRA, and $194,116 in lake make up charges, attributable to water used in steam power generation and/or lost to evaporation at LCRA's cooling ponds. The stipulation provides that LCRA would ". . . eliminate the hydroelectric charge from the settlement revenue requirements". The stipulation indicates that the reduction in revenue requirement attributable to hydroelectric is $3,200,000. The stipulation says nothing about the lake make up charge but the examiner will assume the parties intended to reduce the lake make up charge to $15,718, since that is the sum remaining after reducing the original expense by the amount indicated in the stipulation.

LCRA computed its proposed hydroelectric charge by multiplying the ten-year (1978-1987) average hydroenergy kWh by the value of the lowest replacement cost fuel, in this instance, western coal. LCRA argued that the ten-year average of 231.2 gWh at an assessed "value" of 1.307 cents/kWh yielded a proper hydroenergy charge. Several parties, including SMI/TIEC, PEC, and the staff argued that the proposed charge was not cost-based since it was based on the value rather than cost of service and that the entire sum should be disallowed. San Marcos witness Revell argued that it was improper to use a replacement cost fuel to assess a value, because the coal which was being used has no value after being consumed to produce the energy, whereas stored water retains its full value after being used to produce energy. He reasoned that therefore an assessment of costs is contrary to cost of service principles and that the replacement cost proposed negates the cost advantage of hydroelectric generation. AWC witness Stover disagreed with the use of 231.2 gWh, finding that it differed from the amount of generation used in computing the fixed fuel factor and that it included an abnormal year, 1987, when there was excess water run-off in the LCRA system. He argued that if a charge were to be adopted, the median rather than the average should be utilized.

Further elaboration on this issue is difficult because portions of LCRA's prefiled testimony on this issue were deleted pursuant to the stipulation. The examiner finds that the stipulation concerning the hydroelectric charge should be adopted based upon the discussion above.

3. Incentive Retirement Program

LCRA instituted an early retirement program in the summer of 1987. The total cost of the program is $5,640,000, which LCRA proposed to amortize over five years. The program involved the reduction of 27 positions and the replacement of other positions at lower annual salaries. As a result of the reduction in work force, increases in salaries were offset and a test-year end payroll adjustment was not proposed. LCRA originally proposed to increase its O&M expense by $1,372,072, to recognize the annual cost of this incentive retirement program. As pointed out by several intervenors, LCRA had already included $471,440 in test-year expenses attributable to this retirement plan. LCRA and the intervenors agreed in the stipulation that its revenue requirement should be reduced by $450,000, in order to prevent a double recovery. The examiner agrees that this is a reasonable reduction and recommends that it be adopted.

4. FPP 3 payroll

LCRA had proposed to increase its O&M expenses by $7,995,300, to reflect payroll and additive costs of 194 FPP 3 personnel currently on the payroll and 32 budgeted but unfilled positions for FPP 3 which were expected to be filled by the beginning of the rate year. LCRA's total FPP 3 payroll with additives for the 194 persons totalled $6,722,299. It computed the payroll and additives for the additional 32 personnel by taking the average salary of the 194 current employees, or $34,751, to arrive at an additional $1,108,832, to be added to the current salaries to reach a total of $7,831,131. LCRA's prefiled evidence also showed however, that the total budgeted salaries for those additional 32 employees was $727,000. With a 23 percent additive, that would total only $894,210. Adding that sum to the current salaries results in a total of $7,616,509. Due to the stipulation, the discrepancies regarding this expense were not cleared up.

An additional problem pointed out by several intervenors was that LCRA had multiplied hourly rates for employees working 12-hour shifts by 2,288 hours when the correct number should have been 2,184 hours, since the employees alternated three- and four-day workweeks. Computing the wages for 12-hour employees using the correct number of annual hours would reduce the expense by $89,092. Other intervenors argued that the staffing level was too high based upon averages in the southwestern region and in comparison with the staffing for FPP 1 and FPP 2. LCRA's proposed 226 employees for FPP 3 represents 0.57 employees per megawatt (assuming FPP 3 is 400mW). In comparison, FPP 1 and FPP 2 operate with 0.28 employees per mW and the average staffing in the southern United States is approximately 0.25 employees per mW. The average staffing in the south, of plants of 400 to 2,000 mW, that were constructed after 1970 equals approximately 0.23 employees per mW.

As part of the stipulation all parties agreed to reduce LCRA's FPP 3 payroll by $500,000, for a total of $7,495,300. As pointed out in the stipulation evidence, several intervenors had argued that the unfilled positions did not meet the known and measurable standard. Based upon the discrepancies noted above related to the computation of salaries for those unfilled positions, the examiner finds this argument persuasive and recommends acceptance of this portion of the stipulation.

5. Miscellaneous

As indicated above, there were several issues raised by the prefiled testimony which were not specifically addressed in the stipulation of the parties. These issues are briefly discussed in this section of the report because the expenses associated with the various items are implicit in the stipulation.

a. <u>Coal handling</u>

LCRA proposed to increase the coal-handling O&M expense by $6,915,711. Included in that sum is $3,989,744, associated with Decker litigation, a lawsuit between the Decker Coal Company and LCRA and the City of Austin concerning a coal contract. That litigation ended in an agreement whereby LCRA and the City of Austin each agreed to pay one-half of a $55,000,000 settlement to Decker and were released from any further requirement to accept coal under the contract. LCRA argued that the Decker Settlement represented a potential savings to ratepayers of more than $600,000,000 during the term of the contract.

Four of the intervenors argued that the litigation expense should be amortized over the same period as the settlement payments, 14 to 15 years. Intervenors advocating that position included GVEC, SMI, San Marcos and AWC. Other intervenors argued that the entire expense should be disallowed because it was non-recurring and a material expense. PEC witness Avera argued that this expense had already been paid by LCRA, which, unlike an investor-owned utility, should not be allowed to treat these expenses as investments by shareholders to be repaid by ratepayers. He argued that since LCRA's rates are set on a cash basis, there was no need to capitalize the expense and amortize it and that, instead, it should be removed. OPC witness Allen concurred in this position and BEC et al. also felt that the entire expense should be disallowed. The Commission staff supported the inclusion of this expense in LCRA's O&M expense. LCRA presented the rebuttal testimony of Mr. Bartley, in which he testified that LCRA expected continuing fuel-related litigation expenses, specifically with respect to transportation agreements, of approximately $500,000 per month and therefore argued that the litigation expense included in the proposed increase for coal-handling O&M should be continued as a recurring expense.

The examiner is not wholly persuaded by LCRA's position and without the stipulation would probably be persuaded by Dr. Avera's argument. The examiner believes it is important that the record clearly reflect that this expense is included so that when LCRA files its next rate case, this O&M item is not overlooked. However, in light of the stipulation of the parties and finding the end result to be reasonable, the examiner recommends that the Decker litigation expense not be disallowed.

b. CP&L power bill

LCRA proposed an increase related to its cost of electric power used in its Lakeside and Gulfcoast water divisions but noted that it represented a total company adjustment which was then allocated entirely to water and eliminated from the electric cost of service on the line titled "Allocated Water and Environmental". See page 12 above. The examiner finds this adjustment reasonable.

c. Decreases proposed to test-year O&M

LCRA proposed to decrease O&M by $8,061,293 directly attributable to expenses associated with LCRA's activities in water and environmental activities. It also proposed a decrease of $1,988,591, to reflect the elimination of water and environmental expenses allocated to those functions through its cost of service study. The third decrease proposed by LCRA to its O&M expense relates to the cooling efficiency program. The $1,583,638 was deducted because LCRA's current practice is to capitalize the expenses associated with that program. As part of their stipulation, the parties agreed that this capitalization would continue.

A fourth decrease proposed by LCRA was for franchise requirements totalling $258,839, related to gross receipts assessments in the retail district. Since LCRA has sold the San Marcos, Kerrville and San Saba districts to those respective cities, the expenses associated with those operations are being eliminated. LCRA further proposed a deduction of $3,225,617, related to retail O&M associated with the retail operations of San Marcos, Kerrville and San Marcos and charged to the cities under LCRA's operating agreements with the cities. Finally, as previously indicated, LCRA proposes to eliminate all purchased power expense since LCRA assumes it will generate sufficient energy to meet the requirements of its customers.

d. Miscellaneous

There were several other minor adjustments proposed by various parties which are briefly listed here for the information of the Commissioners and on which no action is proposed by the examiner. BEC et al. proposed to decrease maintenance expenses for the Ferguson Power Plant, based upon the understanding that the Ferguson plant had been taken out of service for scheduled maintenance twice during the test year, rather than only once, as the normal maintenance schedule calls for. BEC Exhibit 1, page 9. OPC witness Allen recommended the decrease of various expenses to reflect the benefit of increased staffing, e.g., legal and operational review. OPC Exhibit 1A. The staff and OPC recommended decreases attributable to lobbying activities, pursuant to P.U.C. SUBST. R. 23.21(b)(2)(A). The staff also recommended minor reductions attributable to dues and membership fees disallowed under P.U.C. SUBST. R. 23.21(b)(2)(E). Staff also recommended minor adjustments for travel and entertainment expenses. See, General Counsel Exhibit 6.

D. Depreciation

LCRA's original proposal to reduce its depreciation expense by $1,088,969, resulting in a total depreciation expense of $17,068,426, was accepted as part of the stipulation. The decrease is related to the elimination of depreciation expenses attributable to water operations ($353,708) and to the retail district operations ($735,261).

Staff witness Keith Rogas provided testimony and several recommendations concerning LCRA's proposed depreciation rates and practices, and depreciation and amortization expenses. First, Mr. Rogas noted that LCRA uses a 35-year service life for each of its fossil fuel generating units, which is based upon a depreciation study performed in 1984. Mr. Rogas testified that LCRA itself recognized that its fossil fuel generation plants would "more than likely have service lives longer than 35 years". Mr. Rogas determined that a more appropriate service life would be 40 years. He based this determination upon an historical analysis which showed that in past decades units were retired earlier in order to replace them with more efficient larger units. He states that in the 1970s, due to lower, erratic load growth, construction cost escalation, rising interest rates and difficulties in locating new power plant sites, the replacement of operating units became much less attractive. Now utilities are refurbishing units ("life-extension") in order to extend their lives beyond 40 years. He testified that use of a 40-year service life would recognize the option to extend the operations to 50 or 60 years.

Mr. Rogas also testified that while a generating unit may operate for 40 years, components such as pumps may wear out before 40 years and have to be replaced. The replaced components are called "interim retirements," while the replacement components are called "interim additions." Estimates of future interim retirements are speculative and unnecessary in his opinion, and even if they could be accurately estimated, interim additions would still not be accounted for. Mr. Rogas therefore concluded that depreciation rates should be frequently updated using the forecast method to account for <u>actual</u> interim retirements and additions. He cites two dockets (Docket No. 7195, GSU and Docket No. 7510, West Texas Utilities) as two recent rate cases in which the Commission adopted his recommendation that <u>estimated</u> future interim retirements not be included. Based upon a 40-year life he recommended that LCRA's annual depreciation expense be reduced by $710,663 to $16,357,763. That reduction includes an acquisition adjustment totalling $50,392, attributable to LCRA's purchase of a transmission line from the City of San Antonio in fiscal year 1985, which purchase and resulting acquisition adjustment were approved in Docket No. 5850.

Mr. Rogas made several recommendations concerning future LCRA cases, including a requirement that LCRA update the production plant depreciation rates and expense by using test-year-end account balances to account for actual interim retirements and additions, and utilizing the methodology set out in his testimony. He also recommended that LCRA have a depreciation study performed for its transmission, distribution and general plant approximately every five years, unless substantial changes in the plant necessitate a shorter interval between studies. These studies are needed because LCRA sold its retail operations after the 1984 depreciation study, and those sales may have significantly changed the composition of LCRA's plant.

The examiner recommends that the stipulated depreciation expense be adopted, and that the recommendations of Mr. Rogas concerning future depreciation studies be accepted and LCRA be ordered to conduct the studies as indicated.

E. <u>Return and Debt Service</u>

The non-investor-owned characteristics of LCRA's service to the public necessitates an analysis of its cost of service on a cash flow basis. The components of that analysis include O&M expenses, debt service requirements and a reasonable debt service coverage component. The sum which LCRA characterizes as "available for debt service" is the same as the sum of depreciation and return for investor-owned utilities (IOUs). A rate of return and return dollars can be calculated, but it should be emphasized that it is a fall-out number resulting from the debt service and debt service coverage requirements of the utility, not an independently calculated rate of return like that calculated for IOUs.

LCRA had originally proposed a test-year-end adjustment to decrease its "return" by $5 million and a pro forma adjustment of $37.7 million resulting in a total return of $104,348,330. See page 9 above. Pursuant to the stipulation of the parties, LCRA's total funds available for debt serivce has been decreased from $121,416,756 to $117,316,756. Breaking this down into the components normally utilized by the Commission for IOUs, it includes depreciation of $17,068,426, and return dollars of $100,248,330. This reflects a rate of return of 10.07 percent based upon an invested capital of $995,313,512, which includes construction work in progress (CWIP) of $468,129,695. With CWIP deleted, the fall-out rate of return would be 19.01 percent. According to LCRA's calculations this will result in debt service coverage of 1.27x. If the proceeds from the sale of the retail cities is included, the coverage increases to 1.35x. LCRA's invested capital is as follows:

Plant in Service	$641,374,643
Accumulated Depreciation	(178,789,659)
Net Plant in Service	462,584,984
CWIP	0
Working Capital	48,039,787
Capitalized Conservation Programs	534,955
Contributed Capital	(2,564,323)
Deferred Charges	18,588,054
TOTAL INVESTED CAPITAL	$527,183,457

LCRA's Board of Directors set a goal of 20 percent equity for internally generated funds. It was the single most important factor in determining the 35 percent coverage level designed into its proposed rate. The proceeds from the sales of the Kerrville and San Saba systems were used to reduce the revenue requirement in the application by $6.7 million. Those proceeds were placed into the general improvement fund, which, under LCRA's bond resolutions, may be used for debt service only if other funds are not available. Those proceeds are not considered "revenues" in LCRA's resolutions and are therefore not included in the debt service coverage ratio.

LCRA's financial model assumes demand and energy forecasts, construction cost and schedule to support the demand forecast, fuel cost, O&M cost, interest rates and escalation rates. The model balances construction funding between debt financing and revenues produced by rates. The model assumes that the revenues must produce equity for construction and be sufficient to achieve the target of 20 percent equity. LCRA presented evidence that if the equity target were to be dropped, its debt rating would be lowered and its debt would cost more in the future. It argued that a debt coverage of 1.35x would prevent its equity from falling below its 20 percent goal. The rate case was filed, in large part, because of increased debt service and coverage requirements associated with the second step of a three-step phase-in of the debt associated with FPP 3. Those requirements totalled $121,000,000 for the rate year.

BEC et al. witness Blumenthal pointed out in her prefiled testimony that LCRA's debt service for the rate year assumed $100,000,000 of outstanding tax-exempt commercial paper (TECP) based upon a projected issuance of $50,000,000 in December 1987 and $50,000,000 in June 1988. In fact, LCRA issued only $23,625,000 of TECP in December 1987. Assuming all $50,000,000 was issued in June 1988, the total outstanding TECP would equal only $73,625,000, which at five and one-half percent interest would result in a downward adjustment of debt service of $1.4 million. Ms. Blumenthal also urged that the debt service coverage should be similarly reduced, assuming a 1.35x adjustment resulting in a downward adjustment of $507,719.

The City of San Marcos criticized LCRA's proposed debt service coverage ratio and its allocation of debt and debt service coverage. Dr. Belmont argued that LCRA's prior debt service coverage ratios were higher than the indenture or bond resolution requirements in response to LCRA's substantial construction program and resulting increased dependence on external financing. He argued that now that LCRA's construction program is winding down, the need for external financing has decreased. He recommended a range of reasonableness for debt service coverage from 1.2x to 1.25x. Ms. Brown argued on behalf of San Marcos that the allocator should be based on the assets financed by the debt rather than the percentage of total system rate base assigned to the electric or water operations. She reasoned that LCRA's rate base, upon which it allocated its debt and debt service coverage, includes many items which are not associated with debt or debt service coverage, e.g., deferred items such as interest on CWIP, the Texland settlement, Powell Bend Mine costs, and expenses associated with the cooling efficiency program. Her allocator would reduce the revenue requirement by $305,000, assuming acceptance of LCRA's coverage rate of 35 percent. She also argued that portions of rate base are funded by contributed capital, and that the net plant of Buchanan and Mansfield is less than the contribution and therefore results in a reduction of debt and debt service coverage for electrical operations. She also testified that electrical operations subsidize water and environmental operations in instances in which those operating expenses exceed the revenues from those sources. She finds that this subsidization means that a debt service coverage of 1.35x for electric operations provides coverage for the entire LCRA system of 1.3355x.

OPC argues that two adjustments should be made to LCRA's requested level of funds available for debt service. Dr. Szerszen testified that a September 30, 1987, financial report showed a 1.5x debt service coverage ratio in accordance with the bond indenture resolution, as opposed to the 1.15x coverage shown on LCRA's Schedule A of the rate filing package, which calculation utilized the Commission's method for calculating coverage. Dr. Szerzen argues that LCRA has access to the tax exempt bond market and therefore can borrow money at relatively low rates, and that LCRA's customers' opportunity costs of money are likely to be far above LCRA's cost of borrowing. She recommends a 1.3x coverage ratio, which she testified would allow a 1.35x coverage ratio on senior debt, 1.25x on junior debt, and 1.0x on tax exempt commercial paper. Her recommendation would result in a $4.357 million reduction in revenue. OPC recommended a second adjustment attributable to a disallowance that it argues is necessary to prevent LCRA from recovering disallowed expenses from ratepayers through excess debt service coverage. In particular, Mr. Allen for OPC argued that disallowed expenses such as lobbying expenses are paid out of money awarded as debt service coverage. In order to create an incentive for LCRA not to expend these disapproved funds in the future, Mr. Allen argues that the debt service coverage allowance should be reduced by the sum of the disallowed expenses.

AWC, through the testimony of Neil Eisner and Carl Stover Jr., recommended a debt service coverage ratio of 1.2x, excluding revenue from the sales of retail systems and construction fund interest income. If those two sources of funds were included, debt service coverage would be equivalent to 1.32x. Based upon Mr. Stover's synchronization factor, AWC recommended a total coverage equalling approximately $103 million.

Staff witness Kentton Grant presented evidence concerning a recommended fair return on LCRA's invested capital and the need for inclusion of CWIP in rate base. LCRA's test-year debts totalled $1.34 billion which included $1.13 billion in junior and senior lien revenue bonds, $167 million in adjustable rate revenue bonds and $42.6 million in commercial paper. Its retained earnings (equity) grew steadily between 1982 and 1987, and its equity capitalization ratio was 20.3 percent at the end of the test-year. LCRA's debt service does not include capitalized interest on FPP 3 and the Cummins Creek Mine. However, as the capitalized interest on those projects is phased out, its debt service payable from revenue will increase substantially (to approximately $120 million total debt service by 1991). In order to reduce the rate impact of that phase-out of capitalized interest, LCRA is proposing to reduce the amount of interest capitalized on its priority revenue bonds from $64.3 million during the test year to $42.2 million in 1988, $28.9 million in 1989, $14.8 million in 1990 and $4.9 million in 1991. The increase in debt service from $55.1 million in the test year to an estimated $91.2 million in the rate year is due in large part to the reduction in capitalized interest.

The Commission staff interprets the LCRA Board statement of financial policy as requiring a 20 percent equity to capitalization ratio over the long run. Mr. Grant points out that the target equity ratio utilized by LCRA in its rate filing package is actually a "net equity assets" ratio utilized by Standard and Poors, where the equity ratio is equal to the net equity assets divided by the total equity asset. Mr. Grant testified that this identifies the unleveraged portion of the assets included in the calculation.

Since LCRA has no equity investors, it does not need to earn a profit, but it does need a return, or margin, over and above its cash operating expenses in order to meet the requirements of its debt obligations, to provide debt service coverage sufficient to allow access to the capital market, and to provide an internal source of construction funds. The use of internally generated funds is an alternative to debt financing which has a concommitant interest cost which raises the total construction costs. There is a need to balance current and future revenue requirements, based on fairness to current and future ratepayers and LCRA's financial viability. LCRA's debt covenants specify a minimum coverage level to which a margin of safety must be added in order to insure confidence by lenders. LCRA's debt covenants define debt service coverage as the net revenue available divided by the debt service, exclusive of capitalized interest. Net revenue is defined as operating revenue plus interest income (excluding interest in construction fund) less the operating expenses (excluding depreciation). In order to determine LCRA's debt service coverage the return and depreciation are divided by the debt service.

CWIP should be allowed a return under PURA only if necessary to the financial integrity of the utility. The key to the return issue here is LCRA's need for continued access to debt capital at reasonable rates and terms. Since the return is based on financial integrity requirements and provides for debt plus a margin, LCRA's financial situation does not represent an exceptional circumstance (See PURA §41(a); SUBST. R. 23.21(c)(2)(D)) warranting inclusion of CWIP, in Mr. Grant's opinion.

LCRA's test-year debt service coverage (1.14x) and its target debt service coverage (1.35x) are below the average (1.47x) and median (1.44x) levels for comparable "A"-rated municipal utilities. LCRA's test-year equity level of 20.32 percent is slightly lower than the average (21.78 percent) and higher than the median (15.73 percent) values. Its current and quick ratios, which measure liquidity, are in line with comparison groups. Mr. Grant testified that three factors have served to reduce LCRA's risk profile recently, including the completion and successful operation of FPP 3; the extension of wholesale power contracts with its two largest customers; and settlement with the Decker Coal Company. He concluded that a 20 percent equity to capitalization ratio is reasonable for LCRA but that debt service coverage should be in the range of 1.30x to 1.35x.

Based upon the foregoing discussion, the examiner finds that the settlement reached by the parties, which will result in $117.3 million available for debt service and a 1.35x debt service coverage (with retail sales proceeds), is reasonable. The examiner further concludes that the fall-out rate of return, without CWIP, of 19.01 percent is a reasonable return on invested capital used and useful in rendering service in light of LCRA's characteristics, cash flow analysis, DSC, and equity/capital ratio. The return is a fallout and does not have the same importance for LCRA as for an IOU. The examiner finds that the utility has failed to prove the need for the inclusion of CWIP as an exceptional form of rate relief since its inclusion is not necessary to the financial integrity of the utility.

F. Other Revenues

LCRA's rate filing package reflected test-year other revenues totalling 58.9 million; adjustments totalling 36 million; and an adjusted test-year and <u>pro forma</u> rate-year other revenues of $22,944,649. As part of the stipulation, LCRA agreed to increase its other revenues to $29,644,649, attributable to increases in interest income, wheeling revenues and off-system sales revenues. Each of those modifications will be discussed in turn, followed by a brief discussion of other issues related to other revenues which are not specifically addressed in the stipulation. The changes to test-year other revenues as reflected in LCRA's prefiled testimony and in the stipulation, are as follows:

Test Year Other Revenues			$58,980,766
Decreases:			
Water & Irrigation		$ 4,877,521	
Water Quality Program		129,623	
Allocated Water & Retail		267,869	
Marina License Fees		128,069	
Parks & Lands		366,426	
Interest Income Revenue Fund		7,202,489	
Interest Income Const. Fund		22,385,994	
Gain on Disp. of Property		2,450,790	
Gains on Refunding	1594	2,401,989	
TOTAL DECREASES			($40,210,770)

Increases:		
Retail Sale Proceeds	6,874,653	
Wheeling Revenues	2,000,000	
Off-System Sales Revenues	2,000,000	
TOTAL INCREASES		10,874,653
Pro Forma Other Revenues		$29,644,649

1. Interest Income Revenue Fund

LCRA originally proposed to reduce (for ratemaking calculations) its booked interest income by $9,902,489, attributable to lower balances in its revenue and general improvements fund attributable to lower coverage levels; less money in its priority bond fund; lower interest rates; and changes in tax laws.

Dr. Avera for PEC testified that LCRA proposed the decrease based upon an interpolation of data to estimate income for the rate-year. Based upon his analysis of the actual interest income for the period October 1, 1987 through March 31, 1988, which he analyzed and allocated to the electric department, he found that the proper known and measurable change should result in a reduction to test-year revenues totalling $7,190,068. Dr. Belmont, for City of San Marcos, proposed to increase LCRA's projected interest rates by 100 basis points resulting in total interest income $3.2 million greater than LCRA had projected. OPC witness Allen took the position that the proposed reduction was not a known and measurable change and should be disallowed in its entirety. AWC witness Eisner testified that LCRA's downward adjustments were too large and projected that LCRA would earn more on its fund balances. Mr. Stover, also testifying for AWC, recommended a total increase of $7.9 million over LCRA's request.

As part of the stipulation, LCRA and the parties agreed to increase LCRA's interest income by $2.7 million, thereby lowering the adjustment to $7,202,489. The examiner finds, after reviewing the evidence of the parties, that this adjustment is reasonable and recommends its adoption.

2. Wheeling Revenues

LCRA's rate filing package did not propose any adjustments to the test-year wheeling revenues. Two intervenors objected to this position, including BEC et al. and AWC. They based their objections on currently pending Docket No. 6995, Petition of LCRA et al. for Determination of Wheeling Impact of the Transmission of Bulk Power from Oklaunion Unit No. 1 to the Public Utilities Board of the City of Brownsville. AWC witness Stover testified that LCRA had also proposed to wheel 20 mW for Texas-New Mexico Power Company beginning in June 1988 but that no revenue impact estimate was available at the time his testimony was filed.

The parties stipulated that the base-rate revenue requirement would be offset by additional wheeling revenues of $2,000,000. The only evidence concerning an exact dollar sum comes from BEC et al. witness Blumenthal's estimate that Docket No. 6995 will yield $368,000, and AWC Stover's testimony concerning Brownsville, in which he assumes it will yield $100,000 of additional revenue. The examiner is concerned about the lack of evidence to support this portion of the stipulation, but since it represents the agreement of the parties, and since the end result is reasonable, recommends that the stipulation not be rejected on this basis.

3. Off-System Sales

Mr. Bartley's revised stipulation testimony states, "LCRA also determined that its test year off-system sales (except for broker, split-savings) should be reduced due to anticipated over-capacity in ERCOT in the rate year." LCRA Exhibit 8 at 7. For purposes of stipulation, LCRA agreed that base-rate revenue requirements should be offset by $2,000,000, attributable to off-system sales.

GVEC witness Norwood pointed out that LCRA's test-year revenues attributable to off-system sales totalled $300,300, and that LCRA proposed to delete those revenues entirely, claiming they were not known and predictable. Mr. Norwood pointed out that off-system sales have occurred each month since January 1986 and increased in the months following the test-year end. He predicted that with LCRA's low fuel costs those sales would probably continue, especially with the increased capacity attributable to FPP 3. He recommended that O&M expenses be offset by $177,271, representing the test-year revenue for contract capacity sales. SMI/TIEC witness Stanley testified that LCRA should adjust its revenues by its actual test-year off-system sales, which he testified totalled

$1,541,131. Finally, San Marcos witness Revell, analyzing the most recent six-month period (October 1987 through March 1988) stated that off-system sales had averaged $85,000 per month. He recommended using a more conservative estimate of $60,000 per month for the rate-year, thereby increasing revenues attributable to off-system sales by $720,000.

Once again the examiner is concerned that the proposed $2 million increase in other revenues is not directly supported by any calculation in the record. Nevertheless, based upon a conclusion that the ultimate other revenues and total revenue requirement is reasonable, the examiner recommends acceptance of this portion of the stipulation.

4. Miscellaneous

The first five items listed under the heading "decreases" in the table on page 25 are changes attributable to LCRA's water and environmental activities. The $22.3 million decrease to interest income construction fund is based upon LCRA's debt resolutions, which require those funds to be maintained for construction expenditures only and therefore require removal of those funds from availability to offset base rates. The gain on the disposition of property of $2.4 million is attributable to the sale of the San Marcos system at above book value. The $2.4 million decrease attributable to gains on refunding is necessary because it is a non-cash accounting classification in which actual dollars are not provided to offset base rate revenue requirements.

The increase attributable to retail sale proceeds of $6.8 million results from the sale of retail city distribution systems. The San Marcos system was sold for a lump sum and the second installment from the cities of Kerrville and San Saba are being deducted from this year's base-rate revenue requirement. In conclusion, LCRA proposes to decrease its other revenues by approximately $10,000,000, resulting in a $29,644,649 offset to base rate revenues. Based upon the foregoing discussion, the examiner concludes that this result is reasonable and recommends that the stipulation be accepted in this regard.

G. Summary and Recommendation

The stipulation of the parties specifically states that it "is not to be regarded as the determination of the appropriateness or correctness of any assumption or legal principles that may be employed in calculating the revenue requirements agreed to". The examiner finds the resolution of the issues as set out in the parties' stipulation to be reasonable as a whole and believes that acceptance of the stipulation with the understanding that it provides a just and reasonable revenue for LCRA and avoids the substantial time, effort and expense to litigate these matters, would be in the public interest. The findings of fact set out below address only the final numbers arrived at in the stipulation and the order proposed by the examiner contains the standard language concerning the non-precedential value of settled cases. The examiner would note that although there were two municipalities that participated in this rate proceeding, neither has requested recovery of its rate case expenses nor is there any evidence concerning their rate case expenses.

V. Conservation and Load Management
(CLM) and Quality of Service

As part of the stipulation, the parties agreed that LCRA should continue to capitalize the cost of its CLM program. Mr. Bartley's revised stipulation testimony addresses CLM only to this extent: "Other factors considered were LCRA's compliance with the statewide energy plan, its quality of service, its efforts in the conservation of resources, efficiency of operations and quality of management." LCRA Exhibit 8, p. 10.

Utilities with more than 20,000 customers must satisfy all the requirements of P.U.C. SUBST. R. 23.22. Generating utilities providing wholesale service must satisfy the "utility-controlled" portion of the energy efficiency plan. In the opinion of LCRA and the staff, the end-user requirements of P.U.C. SUBST. R. 23.22 do not apply to LCRA which serves 75 retail customers and 44 wholesale customers. Staff witness Treadway testified that "LCRA <u>must</u> continue to supply only the utility-controlled portion of its energy efficiency plan". But at the same time he also testified that LCRA "<u>should</u> continue to file the end-user portion of its energy efficiency plan" because those programs are significant in terms of their cost and importance in LCRA's resource plan and their impact on the statewide energy plan.

LCRA offers its CLM programs through its wholesale customers. According to Mr. Treadway, most parties in the case are generally pleased with LCRA's current CLM activities. He pointed out that LCRA agreed to the recommendations he made in Docket No. 7512, and therefore Mr. Treadway felt that there would be "no benefit in conducting a detailed review of LCRA's progress at this time" as long as LCRA was continuing to address his past recommendations.

LCRA's energy efficiency goal is to eliminate the need for combustion turbine peaking units in the early to mid-1990s, at a cost below that of the peaking unit. Originally, LCRA hoped to be able to eliminate the need for 200 mW peaking capacity by 1991. However, lower growth projections and refinements in LCRA's data have reduced that to 230 mW by 1998. The lower estimates do not indicate a decreased commitment to the conservation of resources on LCRA's part.

LCRA reports five programs with measurable savings. The Air Conditioner Cycling Program limits the simultaneous operation of residential air conditioners through direct utility control of air conditioner compressors. Similarly, the Water Heating Cycling Program limits the simultaneous operation of electric hot water heaters through control of the heating elements. Wholesale customers may control their monthly peaks in addition to allowing control at the time of LCRA's peak. These two programs are budgeted together and will provide a cumulative peak clipping capability of 127 mW by 1997.

The Cooling Efficiency Program (CEP) is designed to reduce peak demand and energy use by encouraging the installation of high efficiency air conditioners and heat pumps. This program is projected to reduce peak demand an additional 63 mW between 1988 and 1997. The Good Cents Home Program is a performance-based standard for new home construction including multi-fuel and all electric homes with either single or multi-family dwelling units. The program focuses on the down-sizing of air conditioners which results from the increased structural efficiency. The program does not allow electric resistance furnaces but qualifies only high-efficiency natural gas furnaces and high efficiency heat pumps. The peak demand savings is projected to be 15 mW by 1997.

LCRA's Commercial Lighting Rebate Program pays a rebate to retail commercial customers who replace existing fluorescent and incandescent lighting with high-efficiency fluorescent lighting. The peak demand reduction is expected to reach 4.4 mW by 1997. LCRA's Regional Field Representative Program is a set of educational activities which provide technical and administrative support to the other programs.

Mr. Treadway performed an economic analysis of LCRA's CLM programs. The cost benefit analysis was based upon the December 1987 Standard Practice Manual: Economic Analysis of Demand-Side Management Program, which sets out the standards for evaluation of such programs. The model performs 25-year net present value analyses and results in net present values from four perspectives. In Mr. Treadway's opinion, the most appropriate perspective for analyzing LCRA's programs is the Utility Cost Test, which measures the change in the revenue requirements between implementing and not implementing the program. Each of LCRA's CLM programs passed the Utility Cost Test, i.e., the net present values from that perspective are greater than zero. The net present value of all programs is $74,183,680.

LCRA has integrated its conservation savings into its load forecast by preparing monthly conservation and load management impacts which are used in its energy and peak demand forecasts and financial models. LCRA has estimated future CLM program impacts of 17.606 gWh in the rate year, which Mr. Treadway recommends that the Commission adopt as energy adjustments to the rate year. The total CLM cost incurred by LCRA equals $1,313,801, which the staff recommends be accepted.

In summary, the staff found that LCRA had avoided nearly 40 mW as a result of its CEP operation between 1983 and 1987. As a percentage of peak, LCRA's historic achievements were found to be among the largest in Texas. Mr. Treadway found that LCRA would achieve 250 mW reduction of peak demand over a fifteen year period ending in 1998 and in his opinion was in compliance with the statewide energy plan. He recommended that no adjustment pursuant to Section 39(c) of PURA be made to LCRA's rate of return in this proceeding.

Staff witness Boecker testified concerning LCRA's power plant efficiency. He found that LCRA's generating system was operated in a reasonably efficient manner and that existing programs are continuing and new programs are being developed to enhance the efficiency of LCRA's system operations. Mr. Boecker testified that FPP 3 began commercial operation below budget as predicted in 1981 with a capacity between April 28 and May 24, 1988 of 62 percent and an efficiency of 10.24 million Btu/mWh. He found that its net capability was greater than expected at approximately 405 mW and that its performance should improve in the future. He recommended that the Commission order LCRA to provide a detailed evaluation of the cost for delivery of enough lignite to conduct performance tests on FPP 3, prior to its next rate application. LCRA witness Reed testified that the short-term fuel supply for FPP 3 would be western coal, due to its availability. Long-term fuel options for that unit include local lignite, eastern coal and the continued use of western coal. The decision as to the type of fuel will turn on perceptions of relative risk of future price escalation, supply disruptions and local sources of supply.

No party contested the efficiency of LCRA's operation and the examiner finds that LCRA's performance in CLM programs and in the operations of its units reflect sound management. For these reasons and those stated above, the examiner recommends that no adjustment based upon these considerations be made to LCRA's rate of return in this proceeding.

VI. Probability of Dispatch

A. Introduction

1. General Overview

After the parties had reached a stipulation concerning the cost of service or revenue requirement, the remaining area of controversy centered on cost allocation and rate design. LCRA has proposed a methodology known as the probability of dispatch (POD), which is supported by BEC, PEC, OPC and the general counsel. The POD methodology is opposed, or its implementation is opposed, by GVEC, AWC, and SMI/TIEC. For the reasons indicated below, the examiner recommends approval of the POD methodology. The discussion that follows begins with a general explanation of allocation of costs, then describes the POD method, followed by criticisms of the method. The report then addresses other dockets which discuss cost allocation and concludes with a summary of recommendations.

An allocation methodology should accurately reflect the relationship between the services provided and the cost of providing those services; result in fair and equitable distribution of costs among its customers; provide a stable allocation of costs from year to year; and be sufficiently sophisticated to address the major elements of the costs to be allocated. In this case, LCRA, PEC and BEC are proposing that an additional important function of cost allocation should be to recognize the relationship that exists between production capacity and energy costs, i.e. that the cost of plants such as coal units, which are much more expensive to build than gas-fired units, achieve a fuel expense savings, provide fuel diversity, contribute to system reliability and provide a more competitive fuel market. This consideration is referred to as the investment/fuel trade-off.

The process of assigning the costs of retail and wholesale electric service normally involves functionalization, classification and allocation. For LCRA the first step, functionalization of rate base and expenses, involves tracking plant and expenses by major functions including production, transmission, wholesale distribution (transformation) and retail distribution. The transmission function is further broken down, first by voltage level (345 kv, 138 kv and 69 kv), and with further breakdowns for transmission line investment and transformation facility investment. Production plant is functionalized by production capacity and production of fuel. The latter includes those assets whose costs were directly incurred in the delivery of fuel or to minimize fuel expense. Plant investment dedicated to serving retail customers is separately functionalized and directly assigned to the retail cost of service.

The results of LCRA's functionalization study, based upon the stipulated revenue requirement, are as follows:

Production	$121,224,753
Transmission	
345kv	4,804,538
138kv	13,925,405
69kv	3,883,765
Distribution	2,218,887
Retail	422,958

The next step in the process is to classify the functionalized costs. This involves the matching of costs to measurable customer characteristics such as CP (coincident peak) and NCP (noncoincident peak) demands, energy and number of customers. LCRA classifies transmission costs as demand-related, since transmission facilities are sized to meet system and local demands. The distribution costs, excluding those which are specifically customer-related, are also classified as demand-related. The classification of production plant is the issue that is the subject of major controversy in this case.

The production cost of service breakdown under the stipulated revenue requirement is as follows:

Fuel Expense	$108,506,160
Fuel Handling Cost	7,805,711
Debt Service & Coverage on Fuel Assets	7,726,715
Operation & Maintenance Expenses	39,681,174
Debt Service and Coverage on Production Plant	86,044,095
Other Income	(20,032,942)
TOTAL	$239,730,913

LCRA classified as energy the first three items, fuel expense, fuel handling costs and debt service and coverage on fuel assets. Other parties' positions on these issues will be discussed below in Section VIII. LCRA classified the labor portion of O&M to demand and the material portion of O&M to energy. The major controversial issue is the classification of production plant debt service and coverage which, under the POD methodology, would be split between the demand and energy charges. LCRA's current classification methodology puts all of production plant debt service and coverage into the demand portion. The current methodology is known as a "peak responsibility" methodology.

The final step in most cost of service studies is the allocation of classified costs to customer classes. Since LCRA has primarily one customer class, its wholesale class, its cost of service study does not directly include this step. The wholesale rate is developed from the classified net revenue requirement for production, transmission and distribution. The retail customer classes are then billed at the wholesale rate with the addition of directly assigned retail costs.

2. Current Rate Structure

LCRA's current rates are the result of a stipulation reached in its last rate case, Docket No. 7512. Its current cost allocation and rate design are based upon methodologies ordered in its last contested rate case, Docket No. 6027. LCRA's rates include: (1) demand charges, broken down into (a) capacity or coincident peak (CP) charges, and (b) demand, or non-coincident peak (NCP) charges; (2) energy charges, including (a) the base charge and (b) the fuel charge (fixed fuel factor, discussed above); and (3) the customer (or point of delivery) charge. The existing capacity charge contains a ratchet and voltage differential. The demand charge is based on a single demand charge at each voltage level, applied to billing demands determined on the basis of the customer's actual CP demand in the months of July through September and December through February, and the greater of the actual CP demand or 75% of the average of the previously named summer and winter peak months immediately preceding the billing months for the other six months of the year.

3. Rationale for Change

As indicated previously, LCRA's bringing a rate case at this time is attributable in part to the debt service and coverage on FPP 3, which has been brought into operation. LCRA received a certificate of convenience and necessity (CCN) for FPP 3 in Docket No. 3838, Application of Lower Colorado River Authority for Certificate Amendment to Include Generating Unit No. 3 of the Fayette Power Project (September 23, 1982). The examiner's discussion in that case states, in pertinent part, that, "the evidence shows that because of the rising cost of gas, lignite-fired generation is justified on a strictly economic basis . . .(The) gas displacement rationale for construction of new plants is not disputed by any party." Examiner's Report at page 7. The Findings of Fact adopted by the Commission in that case state that FPP 3 is justified "both on the basis of the need for increased capacity and on the basis for gas displacement." Finding of Fact 14.

As part of a settlement with PEC and BEC reached in the summer of 1986, referred to throughout these proceedings as the "Texland Settlement", LCRA agreed to "promptly address the issue of wholesale rate design and revenue allocation on a cost of service basis." TIEC Exhibit 2. In the fall of 1986, LCRA began discussions with its wholesale customers concerning rate design problems perceived by the customers. Those problems included questions concerning voltage differentials and the use of a ratchet.

During the summer of 1987, LCRA obtained amendments to its wholesale power agreements with all but four of its wholesale customers, extending the contracts through the year 2016. The amendments to the wholesale power agreements cover 92% of LCRA's wholesale load, representing 86.2% of the entire LCRA load. BEC Exhibit 6. Provisions in at least some of the extension contracts include a requirement that LCRA establish a Rate Design Task Force (RDTF) in order to maximize customer involvement in LCRA's activities concerning cost of service, cost allocation, functionalization and rate design. Only four customers, including GVEC, the Cities of Bastrop and San Marcos, and Dewitt Electric Cooperative, have not signed the purchased power contract extensions. With respect to GVEC, LCRA has offered it a contract which has been declined. The settlement that was achieved in Docket No. 7512 was similarly conditioned on creation of a RDTF in order to address the problems that the customers had raised concerning LCRA's cost allocation and rate design in that case.

As a precursor to the meetings of the RDTF, LCRA employed Coopers and Lybrand to present to interested customers a rate design course in order to bring the customers "up to speed" on pertinent issues. The RDTF met several times with its customers and the LCRA staff worked with individual customers to "run the numbers" on different allocation methodologies proposed by the customers. At the last meeting of the RDTF, the members were presented with the results of LCRA's proposed POD methodology, which had been previously discussed with them but which contained a new capital substitution provision which had been added to ameliorate the amount of production plant classified as energy related. The LCRA staff, at the conclusion of this final RDTF meeting, was under the impression that the members of the task force were in agreement with their proposed rate design, or could accept the result in this case even if they disagreed with the methodology. The proposal, as originally filed in this case, was therefore presented to the LCRA Board, which approved its filing.

As should be evident from the length of the hearing on this issue, LCRA's customers were not in agreement concerning its proposed cost allocation and rate design. LCRA was in the unfortunate position in this docket of attempting to justify a proposal based upon an agreement that had "gone bust" but which still had the support of some of its customers. Some of the rationales to be discussed below are based upon LCRA's belief at the time of the filing that its customers had agreed to the proposals contained in the original filing. An inordinately large amount of time was spent during this hearing discussing the various meetings of the RDTF, including recounting who said what and what the LCRA staff understood each intervenor's position to be. For the most part, this evidence is unremarkable except as an illustration that two people observing the same event will often report it differently.

LCRA had three reasons to revisit the issue of cost allocation and rate design after Docket No. 6027, including: concerns raised by customers; the provision in its wholesale power contract extensions; and the settlement in the Texland case. It is LCRA's position that its current cost allocation and rate design methodology is in need of change for three reasons. First, LCRA finds that the existing CP method fails to recognize that production investments result in part from the price, availability and diversity of fuels on the system. The CP method assumes that production plant costs were incurred as a result of the need for capacity without considering the role of fuel in the planning and day-to-day operations of the system. LCRA admits that it builds additional capacity to meet its total capacity requirement, but also asserts that it considers fuel and running costs in deciding what type of capacity to add.

The second difficulty with the existing methodology relates to customers who have the technical capability of avoiding the system peak and thereby avoiding LCRA's CP charges. These customers are thereby able to avoid contributing to the capital costs of generating units, which means that other customers must pay those costs.

LCRA's third rationale for change is based on its position that the existing demand ratchet, which allows customers to consume during the system peaks and pay for the consumption during its off peak, sends an incorrect price signal.

PEC, who is in support of LCRA's proposed change in methodology, also argues that it is unreasonable to continue allocating production costs entirely to capacity when LCRA's capacity charge since Docket No. 366 has increased 227%, while its base energy charge has decreased 12%; there are excess reserves in the ERCOT system; LCRA's avoided capacity cost is $0; LCRA will not need additional generation capacity for 8 to 12 years; and LCRA has recently added FPP 3, a large base load unit.

4. Load Characteristics and Capacity Costs and Plans

The appropriateness of an allocation methodology is determined, in part, on the basis of the system load and generation characteristics. A summary of those components of LCRA's system is therefore presented here. LCRA's winter peak load has grown to equal its summer peak load in years of cold weather. That phenomenon is attributable to a large percentage of end-use customers who are residential and small commercial, and the relative unavailability of natural gas for space and water heating in LCRA's service area, as compared to municipalities. Most other utilities, particularly those serving predominantly municipalities, do not have significant winter peaks, due to the availability of natural gas for space and water heating. LCRA's facilities must have the capacity to handle the peak loads and the facilities are therefore related to peak demand.

The cost of building capacity, however, differs among generators and generally capital spent by LCRA on new units has resulted in lower fuel costs, as shown in the following chart:

Unit Name	Fuel Type	Average Heatrate	Fuel Cost $/MMBTU	Fuel Cost Cents/KWH	Booked Cost per KW of Capacity	Total KW Capacity
HYDRO	WATER	N/A	N/A	N/A	$153	241,000
FPP-1	COAL	10,000	1.57	1.57	$436	285,000
FPP-2	COAL	10,000	1.57	1.57	$360	285,000
FPP-3	COAL	10,250	1.31	1.34	$1023	416,000
FERGUSON	GAS	10,500	2.10	2.21	$137	425,000
GIDEON-1	GAS	10,500	2.10	2.21	$92	135,000
GIDEON-2	GAS	10,500	2.10	2.21	$94	135,000
GIDEON-3	GAS	10,500	2.10	2.21	$86	330,000

LCRA's system includes four basic types of customer load shapes. There are two types of high load factor customers, those who have equal summer and winter peaking systems (SWHL - summer/winter high load factor) and those with only summer peaking systems (SHLF - summer high load factor). Similarly, there are two types of low load factor customers, those with equal summer and winter peaking systems (SWLL - summer/winter low load factor) and those with only winter peaking systems (SLLF - summer low load factor). High load factor systems tend to be those that have industrial loads as a large percentage of their total load. Summer peaking systems tend to be those whose residential customers use an energy source other than electricity for heating purposes, which, as explained above, generally occurs in municipal areas having access to natural gas. Finally, summer and winter peaking systems tend to be those in which residential customers predominantly use electricity for heating purposes. The following table depicts the annual NCP and CP load factor for the test year:

	Non-Coincident Peak	Coincident Peak
SWHL	52.43%	78.08%
SWLL	44.91%	49.20%
SHLF	58.66	61.88%
SLLF	45.46%	46.54%

One unique aspect of LCRA's capacity is its use of hydroelectric generation. Its hydro generation units are run to prevent flooding, to meet downstream water irrigation needs and for the purposes of emergency electric generation. While there is some flexibility with respect to the time of day that water is released in order to generate electricity, its availability depends upon weather and the downstream demand. If there is an option during the day of when to release the water, it is most likely to be released during peak rather than non-peak hours.

LCRA plans to expand generation based upon its summer peakloads. It does not plan its generation based upon its winter peak because of the availability of excess capacity in the ERCOT system at a price substantially below LCRA's cost of adding capacity. It is anticipated that the additional capacity available on ERCOT will be available over the next ten years. LCRA has not decided at this time what type of unit it will be adding in the future, with the need forecasted for the late 1990s.

B. POD Description and Interpretations

The POD method of allocating capacity costs is based on the concept of assigning generating capacity cost responsibility to the hours in which individual units are expected to be dispatched. Central to the concept of the POD allocation approach is the economic assumption that production costs are incurred in a manner which minimizes the combined total capacity (capital) and energy (running) cost to serve a load curve. The methodology is flexible enough to recognize operational characteristics which require deviation from a strict economical dispatch approach. In LCRA's case, the results of this methodology have been interpreted to classify production capital costs between demand and energy and to allocate production capital and fuel costs to seasons of the year. See generally LCRA Exhibit 1-F, Schedule P-12, Section I. After ten full days of hearing discussing this methodology it is undisputed that it is a very complex, some say overly so, and sophisticated methodology. The discussion that follows will delve into the intricacies of the methodology's workings. This is a methodology that is not appropriate for all utilities, but is appropriate for a utility which has varying load characteristics and a diversity in its generating units.

The simplest interpretation of the POD results is that it classifies as energy all costs of generating units that are virtually equally allocated to all typical hours analyzed in the methodology (576). This interpretation, however, fails to recognize the dual role of baseload units, or the investment/fuel trade-off. LCRA has, for this reason, proposed a modification to the simple interpretation of the POD to include a capital substitution (CAPSUB) step. This modification, which will be described in detail below, results in a smaller percentage of baseload units being allocated to energy than would otherwise be the case.

1. Determination of Baseload

The first major step in the methodology is to determine the percentage of each of LCRA's generating units which is "baseloaded". Different definitions for commonly used terms can cause great confusion, and that is particularly the case with respect to this methodology. The examiner found the easiest working definition of baseload as utilized in the POD methodology to be those units or portions of units with the continuous likelihood of being dispatched throughout the year, and whose costs are spread equally to all months of the year.

In order to determine the percentage of each unit that would be baseloaded, it was first necessary to determine each unit's threshold dispatch level by month. In order to explain this process, a copy of the calculation for January and February is included as Attachment III. The column headed "Capability" represents the net dependable capacity of each unit, or the capacity which a unit can be depended upon to run, net of the station usage. The capability on the hydro unit is variable because it is based on the average megawatts generated by month over the five years between 1982 and 1986. LCRA deleted data for 1987 because it was an abnormally high year for hydro generation.

The next column entitled "Effective Continuous Rating" is calculated by taking the capacity of each unit, less the forced outage and the scheduled outage rates. The exception is once again the hydro unit, which is effectively derated in the capability column by utilization of the actual average MW generated rather than use of the maximum capability. With respect to FPP 3, which began operation in April of this year, the outage rates were projected by LCRA's production performance department, assuming that the unit was a mature one so as to not incorporate the anomolies of the first year of operation. By multiplying the capabilities' values by the effective continuous rating percentages, the effective continuous rating in MW results, as shown in the fourth column on Attachment III. The dispatch level results from adding the MW capability of the units dispatched previously, e.g. a threshold dispatch level of 256.1 for FPP 2 in January is the sum of the MW for hydro (8.1) and FPP 1 (247.9).

The threshold dispatch levels for each month are then utilized in the probability of dispatch analysis to determine for each hour of an average weekday and weekend in each month the probability of the generating unit being dispatched. An example of this computer run, for FPP 1, is included as Attachment IV. LCRA made this computation based upon load data for 1984 through 1987. BEC witness Foreman utilized the same data. PEC witness Goble constructed hourly load probabilities for the years 1985 through 1987 and studied each year individually rather than all years simultaneously as proposed by LCRA. He testified however that the difference resulting from his interpretation is insignificant. By dividing the probabilities for each hour by 576 hours, the unitized probability is obtained. <u>See</u> Attachment V. A unitized probability of .00174 meant that a unit was "on line" 100 percent of the time during that particular hour of the study.

The POD experts then looked at the resulting unitized probabilities, shown on Attachment V, and determined the lowest probability of dispatch for each unit in any of the 576 typical hours utilized in the methodology. Here again, the experts differed in picking their minimum unitized probability, with Ms. Taylor's approach being the more conservative. She utilized the annual minimum load by picking the single hour's lowest demand over the study period. Mr. Goble utilized monthly minimum loads, finding that the annual minimum load advocated by Ms. Taylor significantly understated the actual baseload level at which the unit ran. BEC witness Foreman agreed with Ms. Taylor's use of the annual minimum unitized probability. This single difference in interpretation results in a significant difference in the results achieved, specifically resulting in Mr. Goble's classifying 75 percent of FPP 3 as energy versus Ms. Taylor's classification of 26.5 percent. The examiner has concluded that adoption of Ms. Taylor's annual minimum unitized probability is appropriate because it is the more conservative approach and furthers the goal of gradualism.

Once the minimum unitized probability is calculated for each generating unit, it is applied to the current cost of each unit to determine the percentage of each unit's current cost which is energy-related. The three experts each performed basically the same calculations and their particular interpretations are included as Attachments VI A, B and C.

The determination of the percentage of each unit which is baseloaded and therefore determined to be energy-related under this methodology requires a calculation of the current cost of each unit. See column 1 in Attachments VI A, B and C. The current costs of all units, except the hydro and FPP 3 units, were determined by trending the booked costs using the Handy-Whitman indices. There was no need to trend the FPP 3 costs since that unit was just completed.

With respect to the hydro units, Ms. Taylor found that use of the Handy-Whitman indices resulted in a trended cost for hydro of approximately $250 million. She found this sum overstated the replacement cost of that amount of capacity and therefore was beyond the realm of reasonableness. She arrived at a current cost of $36,210,132 for the hydro units by utilizing FPP 3 kW costs to reflect LCRA's replacement costs of capacity. She determined that the derated cost was $1,272 per kW assuming FPP 3's capability was 416 MW, and -- by applying that to the monthly derated capacity of the hydro facilities -- determined the current cost shown on Attachment VI-A.

Mr. Goble also utilized this same proxy but included in the total hydro current cost an additional $35 million, representing the capitalized energy savings of the hydro power. This resulted in his original calculation of total hydro cost of $70,634,405, as shown on Attachment VI-B. The settlement in the revenue requirement phase resulted in a change to the carrying charge from 11.81 percent to 11.41 percent, and therefore increased his calculation to $71,841,219. Ms. Taylor conceded during cross-examination that there was merit to his capital cost equivalent calculation.

Mr. Foreman on behalf of BEC utilized an entirely different methodology for calculating the current cost of the hydro facilities, in order to arrive at his projected current cost of $8,351,797 shown on Attachment VI-C. He utilized the effective capacity for each month, based upon the 1982 through 1986 monthly averages, and multiplied that by the <u>future</u> coal plant capital costs, $921/kW, reflected in LCRA's 1987 Resource Planning Options Workpaper. Mr. Goble testified that it would be erroneous to accept the $921/kW figure because it does not include off-site fuel handling costs or site development and therefore understates the alternative replacement cost of the capacity. Additionally, he pointed out that the $921/kW is not derated and if it were, he calculated it would be $1,385, which is roughly the value used by Ms. Taylor and himself. The examiner found Mr. Goble's critique of Mr. Foreman's analysis persuasive and recommends acceptance of the FPP 3 proxy used by Mr. Goble and Ms. Taylor.

On the remaining units, excluding the hydro and FPP 3, Mr. Goble on behalf of PEC calculated the current cost of those units by trending the costs to the end of the fourth quarter of 1987. He found that Ms. Taylor had used 1987 dollars for FPP 3 but had used 1985 dollars for the other units. Compare column 1 in Attachments VI-A and VI-B. The examiner finds it most reasonable to be consistent in the years to which dollars are trended and therefore recommends adoption of Mr. Goble's numbers.

The current costs are then each multiplied by the minimum unitized probabilities times 576 hours to determine the total baseload value. See Attachment VI-A, Column 5; Attachment VI-B, Column 2, and Attachment VI-C, Column 5. This amount is classified as energy-related.

2. Peaker Proxy/CAPSUB

The portion classified as baseload is reduced by a sum equal to LCRA's cost per kW of a peaking type unit. This step of reclassifying a portion of the baseloaded/energy-related cost to demand is also referred to as the capital substitution modification to the POD methodology. Ms. Taylor and Mr. Goble utilized the cost of a single cycle gas turbine reflected in LCRA's 1987 Resource Planning Options Workpaper. That sum is $292 per kW in July 1986 dollars. Ms. Taylor indicated she simply rounded that amount to $300, whereas Mr. Goble testified that trending to 1987 dollars results in a value of $300. The $300 is then multiplied by the derated capacity of each of the units and the percentage of each unit classified as energy to determine the portion of the baseload that will be reclassified to demand. See Attachment VI-A, Column 8.

Mr. Foreman's analysis, while conceptually similar to LCRA's and PEC's, is calculated differently. He used a capacity factor methodology to calculate the baseload contribution to demand and to reclassify a portion of the unit classified as energy to demand in order to recognize its contribution to peak. He found that if a new generating unit is anticipated to operate at less than 19 percent annual capacity factor, then a gas turbine or a combined cycle unit is the lowest cost alternative. A baseload coal unit is capable of a 74.44 percent maximum annual capacity factor and the ratio of 19 percent to 74.44 percent yields 25.52 percent of the current cost of a baseload unit which should be classified to demand. See Attachment VI-C, column 7. Mr. Foreman conceded on cross-examination that a 40 percent capacity factor could also be a reasonable "cross-over" point.

Mr. Foreman argued that looking at future resource plans was more appropriate than utilization of a CAPSUB methodology. Ms. Taylor testified that her CAPSUB methodology was more appropriate than Mr. Foreman's. In LCRA's reply brief, however, counsel for LCRA argues that the CAPSUB methodology is not an integral part of the POD methodology in this case and could be eliminated even though it was originally proposed as a moderating force in LCRA's recommendation. The citation in that brief to Mr. Foreman's testimony seems to imply that LCRA believes his method is not a CAPSUB approach. The examiner disagrees. The difference in the methodologies is as reflected in column 8 of Attachments VI-A and VI-C. Mr. Foreman's calculation results in $116,033,533 of baseload units contributed to demand whereas Ms. Taylor's calculation results in $180,007,099 of baseload contribution to demand. The examiner finds use of the cost of the single cycle gas unit more reasonable due to Mr. Foreman's concession of the variability of his analysis.

3. The Demand/Energy Split

The next step in this analysis is to determine the percentage of the production costs classified to demand and energy. Each unit's cost not classified to energy is classified to demand. Ms. Taylor applies the percentage to each unit's booked cost whereas Mr. Foreman and Mr. Goble apply it to each unit's current cost. Mr. Goble testified that he believed that it was improper to restate the cost in historical terms by using the booked cost because that would ignore the system planners' concerns when determining which plants to build. Ms. Taylor's use of the booked costs results in 27 percent of baseload being classified to energy. Ms. Taylor's prefiled testimony indicated this percentage was 25 percent and she explained that she had simply rounded to the nearest five. However, applying the percentage of baseload contribution to energy to the current cost utilized in her calculations also results in a 25 percent allocation. LCRA originally proposed to moderate this classification by limiting it to 16.2 percent based upon its perceived understanding of an agreement with its wholesale customers who participated in the RDTF. As a result of the revenue stipulation in this docket, LCRA's final proposal is that 18.5 percent of the production plant costs be classified as energy-related. BEC's proposal would result in 33 percent of production plant costs classified as energy-related and PEC's proposal would result in 43 percent classified as energy-related. The debt service and coverage associated with the production plant is allocated on the same basis to arrive at the percentage of production revenue requirement in the energy charge. The resulting production revenue requirement split is as follows:

Party	Demand	Energy
LCRA - Taylor	68%	32%
BEC - Foreman	59%	41%
PEC - Goble	53%	47%

The examiner finds Ms. Taylor's results the most persuasive because it will moderate the shift in costs to the energy charge.

4. Seasonal Allocations

The demand costs are allocated to seasons on the basis of monthly probabilities of dispatch. The resulting percentages for the three parties that advanced the POD methodology are shown on Attachment VII on the line labeled "Seasonality." Note that LCRA, BEC and PEC advocate a change to a four month summer peak instead of the three-month period in LCRA's existing rates. A seasonal capacity charge would also replace LCRA's current CP ratchet. LCRA's present capacity charge is based on the demand ratchet of three summer and three winter months. This distorts cost responsbility because it assigns equal cost to the demands which occur during either period. LCRA's capacity requirements are the result of summer peak demands. Although it experiences high winter peaks, it has greater access to off-system capacity during non-summer months. Its generation planning is based on summer capacity requirements and the POD analysis shows that production costs are substantially higher during the summer. LCRA's current rates contain a voltage differential which all parties except BEC recommends be retained. BEC's position and the discussion of voltage differentials and loss factors will be discussed below in Section X.

The POD methodology also allows fuel cost of each generating unit to be allocated and seasonal average fuel costs to be developed. Ms. Taylor's POD methodology showed that the average fuel costs by season were as follows: summer-\$.01604/kWh; winter-\$.01648/kWh; and off-peak-\$.01559/kWh. Since LCRA was not including all of the production costs that were indicated by the POD methodology should be in the energy charge, it did not propose to differentiate the base energy charge between peak and off-peak seasons. At the time of the original filing, when LCRA was proposing to classify 16.2 percent of the production plant cost as energy-related, Ms. Taylor analyzed the effect of the seasonal fuel differential. She found that the total annual cost difference was minimal, e.g. for New Braunfels, one of LCRA's highest load factor customers, the seasonal differential made a difference of roughly \$10,000 out of an annual total charge of \$20 million.

Mr. Goble's POD methodology provided a fuel cost allocation which he testified he employed as a kWh weighting in the cost allocation study. The average fuel cost by season which he calculated did not flow through to his proposed rates because he did not recommend a fuel factor but only base rates. The appropriateness of the fuel differential will be discussed in more detail below in Section C. 15.

5. Proof of Reasonableness of Rates

Ms. Taylor's prefiled testimony includes a future incremental cost analysis of the cost of providing additional peak demand and energy. She made this comparison based upon her belief that the capacity charge must reflect the future incremental capacity costs in order to allow customers to compare the costs of peak shaving investments against the capacity charge of LCRA. Ms. Taylor testified that a wholesale customer makes investment decisions in energy conservation measures by comparing the cost of conservation against the forecast of savings on the energy portion of its bill and therefore it is necessary to look to LCRA's future incremental energy costs. She concluded that the total energy charge resulting from the POD method was comparable to the short run future incremental cost of producing energy on the LCRA system. The total annual capacity charge, however, is well above the current estimate of future incremental capacity cost, \$40/kW-year. She believes this provides an inaccurate price signal to customers to invest in measures to reduce their monthly contribution to the LCRA system peak to a much greater degree than is warranted based on the current estimate of future incremental capacity cost. However, it supports the POD method which reduces the capacity charge from $72/kW-year to an average of $69/kW-year.

Ms. Taylor calculated the percentage increase for each of its customers relative to the system average. <u>See</u> Attachment VII. She found that it ranged from a high of 1.23x for the Cities of Weimer and Halletsville, to a low of 0.87x for PEC. This represented increases of eight to 11 1/2 percent. Based upon the rule of thumb that the customers' relative rate of return should be no more than 1.5x the system average, she believed that LCRA's proposal to limit the percentage of production revenue requirement placed in the energy charge to 32 percent was supported by this principle of gradualism.

Under LCRA's existing allocation methodology, the percent of production revenue requirement in energy is 20 percent. Although LCRA's POD methodology would result in 38 percent of production revenue requirement being recovered in the energy charge, based upon its understanding of its agreement with its customers at the conclusion of the meetings with the RDTF, it proposed only a 32 percent recovery of revenues in the energy charge. As a result of the presumed settlement with the RDTF and based on the principles of gradualism, the 32 percent recovery of revenue in the energy charge was held constant after the stipulated revenue requirement resulted in a change to the production plant booked investment classified to energy from 16.2% to 18.5%. Therefore, the 32 percent now proposed is the driving factor in 18.5 percent of the booked investment being classified as energy-related and not the other way around.

Under Mr. Goble's recommendation, LCRA's customers would not receive more than 1.3x the system average increase, or 1.4x the average excluding fuel. Mr. Foreman testified that his recommendation would not result in any customers receiving more than 1.5x the system average increase.

C. <u>Criticisms of POD</u>

1. No Justification for Change

Several intervenors opposed to the POD method argued that LCRA has failed to justify a change in its cost allocation methodology and therefore the proposed method should be rejected. Several of them rely upon Texas Alarm and Signal Association vs. Public Utility Commission, 603 S.W.2d 766 (Tex. 1980) in which the Supreme Court found that while "the Commission has discretion to determine the factors relevant to rate design, . . . there are two overriding considerations. The first consideration is consistency. . . the Commission should take caution not to allow a utility to arbitrarily alter factors considered relevant. Utilities are to be consistent in their applications and may not, without supporting evidence, vary their mathematical formulas or relevant factors so as to fit their alleged needs. The second overriding consideration is the burden of proof which is placed on the utility by Section 40(b)." Id. at 773.

The examiner finds that the POD methodology recognizes that some portion of plant investment is made for reasons other than meeting peak demand. In other words, that there is a trade-off for the higher capital cost of the baseload unit with the lower fuel cost attendant to such units. The methodology will result in a price signal that will not overstate the cost to LCRA of its peaking units and therefore be more accurate in allowing customers to make informed decisions based upon the true cost of service. The examiner finds that the POD methodology does more accurately reflect the cost of service and therefore believes that LCRA has met the standard imposed by the Supreme Court in Texas Alarm and Signal Association and that the proposed change is not an arbitrary alteration to their formula for calculating rate design.

2. Avoidance of Peak

Another rationale for the change in methodology advanced by the proponents of POD is that the current methodology allows customers with certain technical capabilities to avoid the system peak, thereby avoiding CP charges and contributions to the capital cost of generating units. The evidence does not indicate that any customer other than SMI, who is a party to this case and a customer of GVEC, has this capability. The evidence is undisputed that during the test year, in eleven out of the 12 months, SMI was able to avoid LCRA's system peak. SMI argues in its reply brief that this avoidance does not increase LCRA's revenue instability since LCRA designed its rates on historical billing determinents and thus takes into account load management efforts. This argument is short-sighted, however, because it fails to anticipate avoidance by additional customers in the future, which LCRA argues will occur if its capacity charge continues to rise disproportionate to its actual cost of building additional peaking units. Intervenors also point out that this rationale for change is inconsistent with LCRA's now offering an interruptible tariff, which will be discussed in detail below. The key distinction is that with the interruptible tariff, LCRA is the one that determines the amount of capacity avoided and the revenue impact, whereas the customers' ability to avoid CP charges based on the current methodology is beyond LCRA's control. The examiner concludes that the criticisms of this rationale for a change to the POD methodology are not well founded.

3. Responsiveness to Customers

AWC elicited evidence throughout the hearing concerning the need for LCRA to be responsive to the wishes of its customers. AWC's focus seemed to be that LCRA needs to give the impression of having achieved a consensus among its customers to ensure favorable bond ratings. AWC makes the rather interesting argument in its brief that since it "represents a broad spectrum of customers, . . . its views should be given great weight." AWC Brief and Closing Arguments at p. 3. AWC presented one witness during the second phase of the hearing, Mr. George Rogers, the utility mananger for the City of Llano. This policy witness testified that while the AWC membership was divided, its concern was not so much with the outcome in this case as with the use of POD in future rate cases. Specifically, his concern was that more production plant would be classified as energy-related in the future.

The voluminous evidence concerning LCRA's involvement with its customers through the rate design task force and other endeavors, including discussions concerning voltage differentials which will be discussed below, convinced the examiner the in fact LCRA is responsive to its customers. It is clear that with a customer group as diverse as LCRA's, a consensus is difficult to obtain. The examiner is convinced that LCRA believed at the time that it filed the instant case it had the approval of those customers who were interested enough in these issues to participate in the RDTF. That LCRA misread its customers, or that the customers subsequently changed their mind concerning this filing, is also abundantly clear. The examiner cannot accept AWC's argument, for to do so would be to abdicate the decision-making process to an association whose members are not fully in agreement themselves. As AWC's reply brief concedes: "The position of the AWC is not one of criticism [of POD], because, as Mr. Rogers testified, the AWC has not reached any consensus on the merits of the POD-based method proposed by the LCRA." Reply Brief at 2.

4. Revenue Stability

TIEC witness Keith Hatfield studied kWh and CP kW between October 1985 and September 1987 in order to determine whether the variance of kWh was greater than the variance of CP kW on LCRA's system. He determined the variance of kWh was almost twice that of the CP kW. Based upon this finding, TIEC witness Stanley argued that placing fixed costs in the energy charge results in revenue instability. LCRA witness Walter Reid, however, testified that energy is considerably more reliable in terms of annual forecasts since it is dependent on 8,760 hours in the year as opposed to the peak demands, which occur in only 12 hours a year. Conceding that energy usage may change more month to month than demand, he testified that on the LCRA system it changes in a more predictable way compared to demand. LCRA's chief financial officer, William Freeman, also testified that as long as 50 percent or more of the production revenue requirement was classified as demand he did not believe there was any financial risk in the allocation of portions of production plant to energy. He testified that he was more concerned with the continued use of the CP allocation which allowed some customers such as SMI to avoid LCRA's coincident peak. LCRA's position is that if the capacity charge continues to increase, additional customers will be encouraged to acquire peaking facilities or avoid system peak. The examiner is persuaded by Mr. Reid's testimony concerning the predictability of LCRA's energy components, and therefore rejects TIEC's argument concerning the variability of the energy charge and instability of revenue.

5. Complexity of POD

It is undisputed and a slight understatement to concede that this methodology is complex. Ms. Taylor testified that it would stretch the limits of LCRA's customers' understanding, but she felt that it should be accepted because it was more important that the customer be able to understand the computation of his final bill than to understand the details of the cost allocation methodology. In that regard, LCRA's proposed rates have the same structure as its current rates, except that the capacity charge has a seasonal cost variation rather than a ratchet of peak season demand. The change should not be any more difficult for customers to understand than the existing rate structure. LCRA has shown its willingness to assist its customers through the creation of the RDTF and through the rate design course which it sponsored for its customers. The examiner finds that the POD is a complex cost-based methodology which should not be rejected on the basis of its complexity. It is important to remember that LCRA's customers are not generating utilities and therefore do not, on a day-to-day basis, deal with the complexity of production costs and revenue requirements. The examiner concludes that the argument concerning understandability of the rates rests on the erroneous assumption that the customer needs to understand computations leading to the rate in order to understand its impact and to plan accordingly. As PEC argues in its brief, there is a conflict between cost-based rates and simplicity of rate structures because the economics and engineering of electrical systems is very complex. The POD methodology allows load management efforts to be guided by accurately reflected system costs.

6. Load Stability

Another criticism leveled against the POD methodology is that it might affect LCRA's projected load. There was conflicting testimony whether or not this would occur but no analysis was done. Intervenors criticized LCRA for failing to analyze the effect of the proposed rates on its future load. At the same time, the same intervenors who were leveling the criticism did not present any analysis to support their criticism that the changes would affect LCRA's load. BEC witness Foreman testified that there was no need to study the potential impact of new cost allocation methodologies as long as they resulted in cost-based rates. GVEC witness Bertram Solomon testified that a change in cost allocation methodology would impact customers' energy and demand usage which could possibly lead to a change in system load characteristics. Mr. Solomon, however, has no experience, in prior dockets or through review of examiner's reports or testimony, with the POD methodology.

Mr. Solomon also argued that LCRA's proposed summer demand charge, which is 47 percent higher than its winter charge, distorts reality because LCRA experiences summer and winter peaks that are equal in years of cold winter weather. The examiner finds that this is not a distortion; the undisputed evidence is that LCRA plans only for summer peaks, because it is able to purchase excess capacity on the ERCOT system during the winter, and anticipates being able to continue doing so for at least the next ten years. GVEC witness Scott Norwood argues that increasing the energy charge sends a signal that the cost of capacity is decreasing and the cost of energy is increasing. He argues that this will result in a decrease in energy consumption and the incentive to conserve or control peak demand. This argument ignores the reality that LCRA's proposed summer capacity charge will be increasing. For example, for 138 kV customers the present capacity charge is $5.933 and the proposed summer charge will be $7.59. Again, since it is the summer period for which LCRA plans additional generating capacity this is the appropriate comparison to make rather than a comparison of the capacity charge per kW-year, which as shown on Attachment VII will decrease from $72 to $69.

For the reasons stated above, the examiner is not persuaded by these criticisms of the POD methodology and therefore finds that they should not form the basis for rejecting LCRA's proposal.

7. High Versus Low Load Factor Customers

Some intervenors criticized the POD methodology claiming that it will result in a subsidization of low load factor customers by high load factor customers. Not suprisingly, this argument is advanced by customers with high load factors. GVEC witness Norwood testified that a high load factor system will, over time, require fewer plant additions, have higher plant operating efficiencies, and produce a lower overall cost of service in comparison to a lower load factor system. He argues that the POD methodology will encourage lower loads and, by reducing the demand charge for most months and on an annual average, will provide less incentive for customers to control peak demand. Mr. Norwood was also of the opinion that the POD is inequitable because the "tilt" of production capacity costs into energy charges results in high load factor customers subsidizing lower load factor customers. TIEC witness Stanley agreed with Mr. Norwood in this regard, and testified that customers with higher than average load factors will overpay LCRA's fixed costs and customers with lower than average load factors will underpay for the use of facilities.

Advocates of the POD methodology argue the converse. Allocating 100 percent of production plant to demand forces the low load factor customers to subsidize the high load factor customers. BEC witness Foreman testified that POD classification of some production plant into energy with a seasonally varying capacity charge will enhance load management. LCRA witness Freeman testified that if the opponents are correct and LCRA loses industrial customers, the impact of such a loss would depend on who the customer was, the total number of customers so lost and the timing of the loss. He was of the opinion that there is no intrinsic value between high or low load factor customers. He testified that lower load factor customers on the LCRA system are valuable at times such as now, when there is excess capacity. From a planning perspective, LCRA witness Lee testified that a combination of high and low load factor customers is the most desirable. The examiner has concluded that the POD methodology assigns the cost of baseload units more equitably on an annual basis, will enhance load management and does not result in a subsidization of low load factor customers by high load factor customers. The examiner is not persuaded that the proposed methodology will result in LCRA's losing its industrial customers.

8. Future Volatility

Several customers criticized LCRA for failing to conduct various studies to show possible impacts of changes on the POD results. For instance, there were numerous hypotheticals proposed concerning changes in the dispatch order of the generating units. LCRA has projected, however, that its gas prices will remain above its cost of coal, and that the order of dispatch vis a vis coal and gas will not change. If FPP 3 is dispatched before the other two Fayette units, Ms. Taylor could not calculate the impact on the percentage of production plant classified as energy-related because the change in unitized probability for FPP 3 would impact the other variables in the POD interpretation.

LCRA's planning options workpaper does discuss the increasing environmental concerns surrounding conventional coal technologies and the possibility that solid fuel generation facilities could be legislated out of existence. These are uncertainties that the future holds, and the examiner believes that it would be unreasonable to expect LCRA to project the impact of these future eventualities under the POD methodology. If such drastic changes do occur, one would expect there would be comparable changes in the cost of service that should be reflected in rates. To suggest that this makes the POD methodology inherently too volatile to be accepted is absurd.

We do know that generally, except for the hydro units, the POD will assign higher probabilities of dispatch in all hours of the year to units that tend to have higher capacity factors and lower probabilities of dispatch to off-peak hours for those units that have lower capacity factors. The probability of dispatch of any unit is a function of load, order of commitment and dispatch, current capability ratings, the units on the system, the forced outage and planned maintenance schedules, and is calculated on an hourly basis so that there is no <u>single</u> probability of dispatch. In this way, the POD, unlike any other methodology, does consider the realities of operation in allocating costs throughout the year. Ms. Taylor was able to testify that if FPP 3's capacity was anywhere within the range of 397 MW to 416 MW, the end results of the methodology, whereby 25 percent of production plant costs are classified to energy, would not change.

If the cost of a peaking unit were to increase, and assuming <u>arguendo</u> that that cost is independent of the other POD variables and would not affect them, the change would be that the classification of production plant to energy would be <u>reduced</u>. If LCRA's load increased and no other variables changed, more baseload units would be classified to energy in order to reflect the fuel savings attributable to the new units going into baseload.

GVEC witness Norwood's testimony to the effect that if gas prices were to drop below coal prices, then a consistent application of POD would require that a portion of the capital cost of the gas-fired units be allocated to energy and all of the cost of the coal-fired units be allocated to demand, is a purely speculative hypothetical which is inconsistent with the reasonable forecasts contained in this record.

9. Cost Allocation vs. Classification

Several opponents of the POD methodology argued that it is a cost allocation methodology being improperly utilized in this case as a cost classification methodology. Ms. Taylor testified that the POD methodology is utilized in this case to classify and allocate costs. Since LCRA has basically one class, the wholesale class, its allocation methodology is a combination of the POD method and billing retail customers at wholesale rates. PEC witness Goble testified that since LCRA has only one customer class, its cost of service study does not directly allocate cost to customer classes; rather, the unbundled demand charges and the rate structure provide the allocation of costs to customers. Using this approach, he testified that wholesale customer systems may be viewed as customer classes and the billing units of the rate as the allocation factors. In this way, the cost of service study and the proposed rate design are linked together.

GVEC witness Solomon also argues that the POD methodology is being incorrectly used as a rate design tool rather than a cost allocation tool. Throughout the hearing, the examiner found all parties, and their attorneys, used the terms "classify" and "allocate", loosely and inconsistently. The examiner finds that the POD methodology is being used in this case both to classify and allocate by seasons and time, but does not find that this utilization of the methodology has been shown to be inappropriate.

10. Generation Planning Assumptions

Several intervenors argue that LCRA failed to show that its generating units were built for any purpose other than capacity and therefore the POD methodology should be rejected. PEC witness Goble testified that the POD methodology presumes that plants are operated as they are planned. The methodology ties the planning and operations together if the operations occur as planned. In other words, baseload units, in a natural cycle, will change their dispatch order and their capacity factor will drop. This comports with LCRA's testimony that most of its gas units were built as baseload units. The fact that LCRA incurred greater costs to build FPP 3 is true whether it was due to the Fuel Use Act, which restricted the construction and use of gas-fired units, or was as a result of a desire to incur lower fuel costs. The final order approving the CCN for FPP 3 adopted the Examiner's Report, which clearly stated that it was justified from an economic viewpoint alone. The final order in that case also reflects that FPP 3 was constructed to meet projected capacity needs. This evidence is at least consistent with utilization of the POD methodology.

The examiner does not find it a necessary prerequisite to use of the POD methodology to analyze the rationale for construction of generating units that are deemed baseloaded under the methodology. It is sufficient to find that the higher capital cost units with their attendant lower fuel costs influence the order of dispatch and therefore support utilization of the POD methodology. It is also important to remember that the POD interpretations utilized by LCRA and PEC do not classify all of the capital costs of their baseload facilities to energy, but split the cost between demand and energy on the basis of a peaker proxy or CAPSUB methodology. Ms. Taylor testified that the planning options available at the time the various generating units were built do not affect the allocation of probability of dispatch in this case but that the current options are what is relevant. The examiner concludes that the criticism concerning LCRA's capacity resource options in the past are not relevant to utilization of the POD methodology at this time.

11. Conservation and Load Management

Critics of the POD methodology argue that by lowering the demand charge the proposed methodology will discourage load management and conservation programs and penalize customers who have moved a portion of their energy requirements to off-peak periods. However, the proposal is to raise the cost of capacity for all levels during the summer peak, as shown on Attachment VII. This increase should continue to encourage conservation. Since LCRA builds generation to meet summer rather than winter peak, it is the summer demand charge that should be analyzed to determine the effectiveness of LCRA's rates in encouraging load management programs. Interestingly, GVEC, who advocates that the percentage of revenue recovered in the energy charge be reduced to 9.5 percent from its current 20 percent, proposes a capacity charge that is only two cents more than LCRA's proposed summer capacity charge for 138 kV service.

LCRA's avoided capacity costs are zero, and it does not anticipate needing new generating facilities for eight to 12 years. For this reason, as PEC argues in its initial brief, there is no need for LCRA to subsidize conservation and load management programs, and if the rates are in fact cost-based, customers will be able to make informed decisions about how much and when to conserve.

Most of LCRA's customers are allowed to construct or purchase peaking units, with some fairly stringent conditions under the amendment to the wholesale contracts. See AWC Exhibit 4, paragraph 4, and GVEC Exhibit 22, paragraph 3.2. Compare GVEC Exhibit 14 (GVEC's contract). Mr. Freeman conceded that the recovery of more costs in the energy charge increases the incentive to high load customers to look at cogeneration, but he argues that this is true with any increase in costs. At this time, LCRA is seeking peak load customers and there is no benefit to LCRA to shifting load off-peak. Interestingly, LCRA is also proposing an interruptible rate, which it seems apparent will act as an economic incentive to high load factor customers to remain on LCRA's system and not seek peaking capacity elsewhere. See Section IX below. To the extent that LCRA is successful in marketing its excess capacity both for peaking and baseload, it will benefit its ratepayers by gaining revenues from outside its service area.

GVEC has historically excelled with respect to conservation and load management programs and its current shedded load capability is approximately 13,000 kW. GVEC also provides load control services and associated advertising and art work to other utilities. It has at least one contract whereby its cost of providing these services is covered with an additional ten percent fee paid to GVEC. GVEC itself is also trying to increase its sales of electricity through programs such as an all electric home program and a security lighting program.

Based upon LCRA's summer peaking generation planning and finding that the POD methodology results in cost-based rates, the examiner concludes that the criticism that the proposed rates will discourage conservation and load management is not well-founded.

12. Errors and Inconsistencies Regarding the Current Costs of Generating Units.

As was indicated in Section VI-B.1 above, the current cost for the hydro units was calculated using the derated cost per kW of FPP 3 assuming a capability of 416 kW. In accordance with testimony at the hearing, it appears that FPP's capability is 405 kW. If the effective continuous rating of 80.42 percent utilized in Ms. Taylor's POD methodology were utilized, the effective continuous rating of FPP 3 would be 325.7 MW rather than 334.5 MW. The resulting cost per kW would be $1,306 per kW rather than $1,272 per kW. This would change the hydro current costs to $37,229,000. The examiner believes that this correction should be made to the methodology, as well as adding the fuel cost savings as calculated by Mr. Goble, which equals $34,631,087, for a total hydro current cost of $72,860,087.

As indicated above, Ms. Taylor applies her percentage of baseload contribution to demand to her booked costs. The booked cost for hydro utilized in her POD methodology of approximately $36.9 million differs from that found in her cost of service study ($31,215,880) because the latter is the booked cost of the hydro facilities less accounts functionalized to stored water. The total hydro cost for the LCRA system is $66.5 million. Ms. Taylor's suggestion on cross-examination that the total cost of these hydro facilities should be functionalized to electric operations due to the revenue requirement stipulation was not clearly explained. Ms. Taylor's testimony on this subject was also rather tentative. The examiner is therefore unpersuaded that this change should be made and finds that it is appropriate to utilize the booked cost as shown on Attachment VI-A.

Another criticism of the cost utilized in the POD application was that the current costs were calculated for different years. In particular, the FPP 3 and hydro costs were stated in 1987 dollars whereas the remainder of the units were trended to 1985 by Ms. Taylor. Mr. Goble caught this inconsistency and corrected it in his POD methodology and the examiner concludes that his resulting total costs figure, stated in the same year, is more reasonable and should be adopted.

13. Other Apparent Inconsistencies.

Several parties implied that the POD methodology assumed the availability of coal-fired units 99% of the time and 100% availability of the hydro units. This evidences a lack of understanding of the calculations in the POD methodology. The 100% and 99% figures represent effective continuous ratings, which can also be called derated capability, which is net of forced and scheduled outages. See Attachment III. With respect to the hydro units the 100% availability means that those units are used when water is available, to the extent it has historically been available. The POD methodology derates these hydro units with respect to their capabilities, as explained above.

Parties have also pointed to the scheduled outages projected by LCRA and claim that these are inconsistent with the assumptions of the POD methodology. See PEC Exhibit 3. However, the scheduled and forced outages assumed by the POD methodology do not attribute outages to the actual periods in which maintenance occurs, because to do so would overstate the value of the capital costs during off-peak periods. In other words, although the Fayette units are maintained during off-peak periods, the need for maintenance is created by energy usage throughout the year and therefore by derating the facilities, the POD methodology assigns the effects of outages to all periods of the year.

Another criticism was that POD makes assumptions that differ from those contained in the PROMOD model. PROMOD is a production costing model used to project the economic dispatch of generating units and is used primarily to forecast the fixed fuel factor. It is not a cost allocation tool. Even with the differences, GVEC witness Norwood conceded on cross-examination that Mr. Goble's POD methodology predicts a fuel cost within 3-4 percent of that projected by the PROMOD model, which is within a reasonable range of error on an annual basis.

It was also apparent that much confusion was attributable to the different terminologies and different usages of the data used in different models. For instance, there was extensive discussion concerning the difference between commitment orders and orders of dispatch. There was testimony making it clear that high capacity factors are not the only consideration in commitment orders and that parties attempting to draw such a conclusion were taking too simplistic an approach. For example, it was shown that the availability of units, unit efficiencies at various load levels, heat rates, incremental fuel costs, and generating agreements with the City of Austin with respect to Fayette Power Units 1 and 2, all affected the commitment orders. There is a danger in using terms without defining exactly what each party means by them. With respect to the term baseload, some parties criticized the POD methodology for characterizing the hydro units as "baseload units", when they are actually used as peaking units most of the time. In fact, the POD methodology assumes that those are used whenever water is available. That means that 100% of the time that they have historically been available on average they will be utilized.

Finally there was an attempt to show that the EEI load data utilized in POD was not net system generation or native load as the experts claimed. The examiner found the testimony was inconclusive on this point. It was shown that LCRA witness Langston's testimony contained load data which, compared to EEI data, indicated the EEI data were not native load, but there was no linkage between the data she had in her testimony and those which the experts utilized in the POD calculations. Ms. Taylor and Messrs. Foreman and Goble all testified that the load data utilized in the POD methodology were for net system generation. Ms. Taylor testified that if the EEI load data she used did include off-system sales, it would not make a significant enough difference to require rerunning the POD.

14. Peaker Proxy/CAPSUB.

Several parties criticized the Peaker Proxy or CAPSUB modification to the POD method proposed by LCRA and BEC. They claim that this deviation has never before been used and should not be accepted. Ms. Taylor testified that she altered the POD methodology to address the criticisms of the method that she considered to be well-founded. In particular, industrial, high load factor customers have criticized the POD methodology which classifies entire units as either baseload or peaking units, for assigning too much of the cost of baseload units to high load factor customers. That criticism is that these units contribute to reliability and energy concerns and therefore a portion of the units should be classified as demand related. By assigning a portion of the units classified as demand related the least cost option of meeting peak demand (the gas turbine) the modification to the POD methodology in this case attempts to address that criticism. It is important to point out that if this refinement is rejected, the effect would be to classify a greater amount of production plant as energy related. Much of the criticism regarding this step in the POD methodology proposed by BEC and LCRA was raised in the briefs of the parties and will be discussed further in the next section dealing with prior Commission actions concerning POD and CAPSUB. The examiner finds the modification reasonable, and consistent with the underlying rationale for the method.

15. Energy Differentials.

Even though the POD methodology will differentiate the base energy charge between peak and off-peak seasons, LCRA did not initially recommend that that differentiation be carried through to the rates. Ms. Taylor testified that she did not recommend a seasonal fuel factor differential because fuel reconciliation is a complex enough process without requiring monthly reconciliations. Ms. Taylor also testified that since LCRA was not proposing to allocate to energy all the production revenue requirement that the POD methodology indicates should be recovered in the energy charge, it did not feel it was necessary to propose a differentiated energy charge. However, upon changing the production plant costs classified to energy to 18.5 percent, Ms. Taylor testified that it would be reasonable to implement a seasonally differentiated fuel charge. She testified that if LCRA is to institute a time differentiated energy charge, she would have to rethink, for consistency purposes, the capacity charge as being the coincident use of a single hour peak. Currently the only peak period defined in the rates is LCRA's monthly peak. She has not yet determined what hours would be included if LCRA were to have a time differentiated energy charge.

Ms. Taylor testified that LCRA has the metering capability to institute a time differentiated energy charge but it currently does not have the billing capability to utilize such a differential. She testified that LCRA would need to develop a computer software program for such a differential and that that would take two to six months.

Mr. Goble, on behalf of PEC, did not propose any energy differentials because he did not recommend a fuel factor. He testified that in a CP&L case involving POD, the fuel costs were allocated similarly to baseload capacity. He testified that the difference between that case and this one is that CP&L has customer classes and had hourly load data available. Mr. Goble further testified that it is difficult to allocate fuel and a differential between the average fuel costs and the allocated fuel costs is embedded in the base rates of the individual customer classes. He conceded that with respect to CP&L, the differential was not merely seasonal but included a differential between high and low load factor customers. He was of the opinion that this could not be done for LCRA because it did not have customer classes.

It appears to the examiner that a basic premise of the POD methodology is that the investment in the high capital cost baseload units is balanced with the lower fuel costs needed to operate those baseload units. Consistency requires that the full allocation of the higher capital costs be balanced with an allocation of the lower fuel costs. As the examiner understands this problem, it is in two parts. First is the issue of a seasonal energy charge, which has been calculated by LCRA and is reflected under the column "LCRA Alternative" in Attachment VII. The examiner believes that a second issue regarding a time differential deals with on-peak and off-peak fuel costs. Based upon Ms. Taylor's testimony, the examiner finds that there is insufficient evidence in this record to determine what, if any, hourly fuel differential should be created. This is an issue that warrants further exploration, and in light of

LCRA's plan to file another rate case in March 1989, the examiner is recommending that the final order in this case require LCRA to explore this possibility and to include such a proposal in its next case, or to include evidence explaining why an hourly fuel differential is inappropriate and its impact upon the investment/fuel trade-off premise of the POD methodology. Since the POD results are not being fully implemented in this case, and the energy charge is not as high as it would otherwise be, the failure to fully implement the lower fuel cost trade-off via a time differentiated fuel charge is not unreasonable.

D. POD and CAPSUB in Prior Dockets

The parties have briefed several prior Commission cases involving probability of dispatch methodologies. After reviewing the dockets which specifically deal with POD methods, the examiner finds that these cases contain sometimes vague descriptions of the methodolgy at issue, or are grounded in the particular factual situations presented in those dockets, and should be given little, if any, precedential value. See Docket No. 2840, Application of Central Power and Light Company for a Rate Increase (January 23, 1980); Docket No. 3716, Application of Southwestern Electric Power Company for a Rate Increase (June 18, 1981); and Docket No. 4400, Application of Central Power and Light Company for a Systemwide Rate Increase (July 29, 1982). In reviewing these cases, as occurred in reviewing the record in this docket, the examiner found that lack of definition of terms and loose use of labels can cause great confusion and obfuscate the issues. Opponents of the POD methodology cited cases dealing with "energy-based allocation methodologies" rejected by the Commission. See Docket No. 7510, Application of West Texas Utilities Company (November 30, 1987); Docket No. 5560, Gulf States utilities Company (October 16, 1984); Docket No. 5640, Application of Texas Utilities Electric Company for a Rate Increase (November 12, 1984); and Docket No. 5700, Application of El Paso Electric Company (October 23, 1984). The examiner concludes from those cases that some parties in other cases have been unable to persuade the Commission of a theory with some similarities to the POD method proposed herein. It would be extreme to suggest that Findings of Fact detailing rate design methodologies in a particular docket take on the import of a rule, which would be the effect if every pronouncement of general principle concerning rate design were given precedential value.

The POD methodology utilized in this case assigns costs, associated with the minimum time the unit is likely to be dispatched throughout the year, to energy. The Peaker Proxy/CAPSUB modification to the methodology is then utilized to reclassify a portion of those energy costs back to demand. In the other cases reviewed by the examiner involving CAPSUB, the costs above the least-cost generating unit were assigned to energy. Once again, labeling something as CAPSUB and attempting to apply findings from other dockets wherein the same terminology was used does not further the analysis of evidence in this case.

Finally, the examiner was surprised to see in the briefs of TIEC and GVEC an argument that LCRA's proposal in this case is a marginal cost approach. It is true that Ms. Taylor's testimony includes a comparison based on the NERA peaker methodology which is a marginal cost methodology. However, as is clearly stated in her testimony, that is provided for comparison purposes only. The examiner was surprised to find the argument advanced that the POD methodology is a marginal cost approach since there is absolutely no expert evidence of record to support this claim. The examiner is certain that if she were to attempt to reach such a conclusion absent evidence of record to support it, most parties would vehemently protest that she was imposing her own expertise that was outside the record, in violation of APTRA. The final briefing after the close of the record is hardly the occasion to advance a new theory of the case. The examiner therefore concludes that there is no basis in this record to support a conclusion that the cost allocation and rate design methodology proposed is a marginal cost pricing mechanism.

E. Discussion and Summary of Recommendations

GVEC's main position was that LCRA's rates should contain "no tilt", i.e. that the energy charge should only recover variable costs. As indicated on Attachment VII, this would move the percent of revenue requirement recovered in the energy charge from its current 20 percent to 9.5 percent. GVEC recommended retention of the 75 percent ratchet as well as a three-month summer peak period.

GVEC was particularly critical of the proposed methodology claiming it would undermine conservation and load management programs, an area in which GVEC has excelled. GVEC argued that the proposed methodology will penalize high load factor users causing industry to relocate or self-generate. Not suprisingly, under GVEC witness Daniel's proposed methodology, the lowest percentage increase would go to GVEC. As shown on GVEC Exhibit 23-E, Exhibit JWD-7, GVEC's proposal would result in its receiving the lowest relative return to the system average, 0.69 percent, representing a 6.43 percent increase. The next closest customer would receive a 7.28 percent increase, representing 0.79 percent of the system average. GVEC currently receives the lowest cost per kWh on the LCRA system at 29.12 mills per kWh, compared to the system average of 33.38. Its proposal would result in other customers of LCRA, whose revenues are currently above the system average, experiencing increases greater than the system average. For instance, the City of Georgetown currently pays 36.42 mils per kWh and would receive a 1.17 times system average increase. GVEC's proposal would exaggerate these inequities by increasing the rates more for customers who are currently paying more. It is important to remember in thinking about GVEC's position that its largest customer, SMI, aligned in these proceedings with TIEC, is able to avoid capacity charges by avoiding LCRA's system peak. This no doubt contributes to GVEC's lower than average rate for electricity. GVEC's increase under LCRA's proposal, 9.0 percent, would still be below the system average of 9.3 percent.

TIEC's position at the hearing was basically one of opposition to LCRA and the others advocating the probability of dispatch. Their witness, Mr. Stanley, advocated a movement towards no-tilt rates on a gradual basis; from the current 20 percent to 15 percent. In their closing brief however, they indicated that they would not oppose GVEC's proposal of "zero-tilt rates". TIEC was also concerned with the retail rates and their relative rates of return, which will be discussed below in Section VIII.

As previously indicated, AWC's position was that the current rate design should not be changed in any regard. In its reply brief, AWC indicates that it is not in opposition to the probability of dispatch methodology because its members had not been able to reach any concensus concerning that methodology. It notes that it is similarly opposed to the proposals advanced by GVEC and SMI/TIEC because it opposes all changes.

Three parties did not present any evidence on cost allocation or rate design. The general counsel filed a statement of position in favor of LCRA's method and urging some changes to the interruptible rate. The OPC's statement of position generally supported the reasonableness of LCRA's approach. The Cities' statement of position was noncommital, but their briefs address the proposed change in the voltage differentials, which the Cities oppose.

The examiner believes this record will overwhelmingly support a conclusion that the probability of dispatch methodology is a complex means of addressing the elements of the allocation of costs. This was an extremely difficult methodology to grapple with, and the examiner deliberated at great length, often finding opposite views prevailing from one day to the next. The recommendation contained herein to accept this methodology is based upon an understanding that the rates that result will not be extreme, that they can be tempered by accepted notions of gradualism, and that they reflect the important energy considerations that are part of the generation planning process. The examiner was convinced that continuing to increase LCRA's capacity charge with the attendant decrease in the energy charge will send the wrong price signal to the consumers because it will overstate the cost of capacity. It is unreasonable for LCRA to continue allocating production costs entirely to capacity when its capacity charge has increased by 227% and its energy charge has decreased by 12% during the same time frame; there are excess reserves on the ERCOT system available to LCRA; its avoided capacity cost is projected to be $0; it will not need additional generation capacity for 8 to 12 years; and it has recently added a large base load unit. The examiner also finds that the proposed seasonal differential in the capacity charge, with the higher summer charge, appropriately reflects LCRA's process of planning replacement capacity for its summer peak alone and its ability to purchase capacity during the winter.

The examiner had requested that the parties address in their briefs prior Commission actions dealing with the probability of dispatch methodology, and read with interest the cases cited that dealt directly with that methodology and all the other final orders and examiners' reports cited by the opponents in support of their various positions. As indicated above, those cases ultimately offered little true guidance for resolution of the facts of this case. While the POD methodology is not without its flaws, LCRA, BEC and PEC have persuasively shown by record evidence that it will result in just and reasonable rates, considering the fuel and running costs of the system, that it will eliminate the possibility of avoiding capacity charges by avoiding system peak, and that it will send an appropriate price signal in light of LCRA's existing and projected generating needs.

This proposal for decision recommends that the determination of current costs be based upon Mr. Goble's computations, including a fuel cost savings for the hydro units and the trending of other costs to 1987 dollars; that the more conservative annual minimum unitized probability recommended by Ms. Taylor be utilized instead of Mr. Goble's; and that the determination of the current costs per kW of the coal plant utilize the derated FPP 3 costs rather than the sum forecasted in LCRA's research planning option paper. In accordance with gradualism principles, the results of the method should be moderated so that no more than 32% of production revenue requirement is allocated to the energy charge.

With respect to fuel synchronization, the examiner agrees with TIEC that the time of day differential should be further examined. The proposed order in this case therefore includes a requirement that LCRA address that issue in its next rate case. In the meantime, this record will support the institution of a seasonal differential in the base energy charge and the examiner recommends that it be adopted. Because the proposal does not incorporate the entire allocation of costs to energy resulting from the POD method (38%), the failure to incorporate the entire fuel trade off with a time differentiated fuel charge should not be prejudicial in this case.

VII. Other Revenue Requirement Allocation Issues

A. Debt Service Coverage for Fuel Assets

Fuel assets includes the Powell Bend Mine, coal cars and related facilities, energy management system and a natural gas pipeline. Under LCRA's current methodology, the debt service coverage on these assets is assigned entirely to energy. GVEC recommended that these costs be treated consistently with other investments made to obtain fuel savings under their methodology and be classified as demand related. The examiner finds that the underlying costs relate either directly to the production of fuel, e.g., the Powell Bend Mine, or are designed to reduce fuel costs. They are not related to peak capacity requirements but to kWh requirements, and therefore should be classified as energy related.

B. Fuel Handling

Fuel handling costs include the cost of the Decker litigation, labor, and railcar lease expenses. LCRA's current rates are based on a methodology that assigns these costs entirely to energy. GVEC argues that this expense should be split 80 percent energy and 20 percent demand, allowing only material and other expenses in the energy-related amount. See GVEC Exhibit 23-D, Exhibit JWD-1. TIEC witness Stanley concurs in Mr. Daniel's recommendation.

The examiner finds that Mr. Daniel is under the mistaken notion that these expenses follow the peak demands rather than kWh sales. For instance, with respect to the Decker litigation costs, he is of the view that it should be classified as demand related because it is fixed. This fails to account for the fuel savings which resulted from the litigation, discussed above in Section IV.C.5.a. The examiner therefore recommends that the fuel handling expense remain in energy.

C. Fuel Inventory

Currently, working capital for fuel inventory is classified as energy. TIEC witness Stanley recommends allocating 80 percent of fuel inventory to demand and

20 percent to energy. In accordance with the testimony of Mr. Lee on behalf of LCRA, it is clear that neither the fuel nor the coal inventory is constant, and that the amounts may vary based on, for instance, an opportunity to achieve savings in the cost of fuel. The examiner therefore recommends that they continue to be classified as energy.

D. Debt Service Coverage

In Docket No. 6027 LCRA was ordered to functionalize debt service requirements associated with all outstanding long-term debt on a five-year construction budget average and SMI/TIEC urges that that decision remain in force. See TIEC Exhibit 15, p. 11 and 13. It is unclear from this record exactly how this item was functionalized in Docket No. 7512. Ms. Taylor testified that the debt service coverage represents dollars that may be used for things other than what appears in the construction budget, e.g. to make up for a shortfall in consumption, O&M expenses and offsetting borrowed funds used to purchase assets. The coverage is driven by the amount of outstanding debt, which was used to purchase the assets which constitute the rate base, and therefore rate base is the proper allocator. The examiner is persuaded by Ms. Taylor's testimony that debt service coverage should be functionalized on the basis of rate base.

E. Off System Sales

As part of the revenue stipulation the parties agreed that $2 million should be attributable to off-system sales. GVEC witness Daniel recommends these revenues be classified almost entirely to demand ($1,850,000) based upon the terms and prices LCRA recently proposed in attempts to make off-system sales. Ms. Taylor allocated these revenues the same as production plant, finding that production plant is necessary to production of off-system sales. She recommended rejection of Mr. Daniel's analysis, because his marketing proposal was an inappropriate allocator, not based on cost of service principles. The examiner finds Ms. Taylor's analysis persuasive and therefore recommends it be accepted.

VIII. Retail Rates

On a test-year, system-wide basis LCRA's classes and numbers of retail customers are as follows: Residential, 22; Small General Service, 31; Medium General Service (MGS), 4; Large General Service (LGS), 16; and Area Lighting, 2. TIEC/SMI raised several issues concerning the LGS rates.

First, TIEC witness Stanley testified that there was an inconsistency in the way LCRA treated the customer costs in determining class revenue requirements. In the design of the Residential, Small General Service, and Lighting rates, LCRA considered each class as a single customer and multiplied the monthly customer cost of $398 by twelve months times one customer to derive the annual customer cost for each class. In the case of MGS and LGS classes, the year-end number of customers was multiplied by twelve and then by the monthly customer charge. In this way, Mr. Stanley testified that LCRA derived a customer cost of $76,416 for the LGS class by multiplying 16 customers times twelve months times $398. Although his testimony does not reflect the specifics of the calculation on the MGS customers, he generally states that the calculation was made the same way. The examiner will assume that the number of customers in the MGS class (four) was multiplied by twelve and by $398 to arrive at a retail class customer cost of $19,104. Mr. Stanley testified that if the LGS class was treated as one wholesale customer, LCRA should have multiplied <u>one</u> customer times twelve months times $398 to derive an annual customer cost of $4,776. This testimony was unchallenged; the examiner finds it persuasive, and recommends the correction be made to the MGS and LGS customer costs.

In addition, Mr. Stanley testified that a significant portion of the customer component of the wholesale rate is associated with common meters. LCRA witness Taylor agreed with Mr. Stanley that the metering costs contained in the $398 charge were not incurred to provide service to the current retail customers and therefore those costs should be removed from the customer charges. The examiner agrees that this change should be made.

TIEC also offered evidence that LCRA developed its proposed tariff by multiplying the existing components of the LGS base rate by a constant factor of 1.3075. It alleges that this fails to correct inequities that exist in the existing rate structure and that the cost components of the rate (demand, energy and customer) should be guided by the pure unit costs of service. Based upon LCRA's cost of service study, Mr. Stanley testified that unit costs indicated a demand charge at $6.92 per kW and a base energy charge of $0.006245/kWh. The proposed demand charge of $6.92 is, in Mr. Stanley's opinion, equal to the unit cost but the proposed energy charge of $0.00754/kWh is 20 percent higher than the cost of serivce. The energy charge for the LGS class was $0.00299 per kWh during the test-year. The rates approved in Docket No. 7512 which became effective October 22, 1987, increased that to $0.00583/kWh. Mr. Stanley argues that the LGS rate should be designed to track costs more reasonably and that multiplying by a fixed factor across the charges in the tariff has the effect of exacerbating existing problems. He suggests that unit costs for providing service should be determined utilizing a "proper" cost classification in a cost of service study and that the LGS base rates should be "designed to follow, as nearly as practicable, those unit costs."

Although this testimony was unrefuted and there was no cross-examination concerning it, the examiner finds that there is insufficient evidence concerning the effect of the proposed changes on other retail rate classes to recommend acceptance of this proposal at this time. Mr. Stanley's testimony is also too general to yield a specific proposal concerning a rate design for the LGS class. The examiner recommends that the final order in this case require LCRA to present evidence concerning the costs associated with retail class rates in its next rate filing.

Finally, TIEC/SMI requests that the LGS rate contain voltage differentials in a manner consistent with the wholesale rate. Mr. Stanley's rationale is that there is no reason for a customer in the LGS class, who can take power at a transmission voltage, not to benefit from the cost savings that are provided for in the wholesale rate. He believes that it would be a simple procedure for the cost of providing service by voltage category to be translated into the retail tariffs and asks that LCRA be instructed to make that translation in this case. This recommendation was not disputed by any party. The examiner does not believe that this proposal would affect any of the other retail classes, and therefore recommends its approval.

IX. Experimental Rider for Interruptible Service

LCRA is proposing an experimental rider to its wholesale customers for resale to the wholesale customer's end-use customers for interruptible service. The experimental rider provides that each end-use interruptible customer's interruptible amount must have a minimum load of 5 MW and limits the availability of the service to 5 percent of the projected net system peak of LCRA, or 100 MW, whichever is less. The rate for interruptible service is the same as for wholesale, except the capacity charge contained in the rate is waived. The term of the contract required under the rider is ten years. The proposed tariff provision contains specific restrictions on when LCRA would be allowed to interrupt a customer, e.g. it would not be allowed to interrupt for reasons of fuel economics, and it would normally be required to give 120 minutes oral notice. There are various other restrictions contained in the proposed rider included in LCRA Exhibit 1-A at Tab 2. The rate also contains a penalty clause that would allow LCRA to charge an interruptible customer two times the capacity charge in the wholesale rate for twelve months if the end-use interruptible customer refuses to interrupt upon request.

The parties were in general agreement in support of the proposed interruptible rider, but there were several criticisms of its terms. TIEC/SMI argued that the ten-year term was too long, and since it was a new provision, the term should be reduced to no longer than three years for the initial contract, with a renewal term of five years. LCRA responds that the term is tied to LCRA's generation planning and that it must be of a sufficient length to allow it to avoid planning generation, or the purpose of the provision is defeated. LCRA will not need to interrupt any customers for several years. The examiner concludes that the customers will receive the economic benefit of the tariff for several years without the attendant burden of interruption. It also seems reasonable to tie the term of an interruptible tariff into the planning process. The examiner therefore recommends that the ten-year term be accepted.

TIEC/SMI also testified that the threshold of 5 MW is too limiting, and would disqualify many industrial customers on the LCRA system. Mr. Stanley recommends lowering it to 2 MW. LCRA's response is that the limit is necessary to minimize the impact on revenues. However, as indicated by TIEC/SMI, the availability of the experimental interruptible service is limited to an amount equal to 5 percent of the projected net system peak. Ms. Taylor testified that the minimum is also tied to the practicalities of administration, including how many phone calls it would be necessary to make in order to get a block of interruption. Without specific data on how many customers would be precluded from utilizing the tariff with the threshold set at 5 MW, it is difficult to arrive at a threshold level that will make the proposed rider attractive to end-use customers. Since SMI is known to be interested in this rider the examiner is inclined to give somewhat greater weight to their recommendation, and therefore recommends that the threshold be lowered to 2 MW.

PEC witness Goble testified that the appropriate discounts for this service should be LCRA's avoided capacity costs. LCRA does not project the need for additional capacity until 1993. The cost of that capacity, reduced to present value, would result in a capacity charge of $1.81 per kW less than the firm rate. The general counsel agreed with PEC's recommendation. There was no rebuttal testimony presented to PEC's proposal. The examiner finds PEC's position persuasive and recommends that the tariff be modified accordingly.

TIEC/SMI witness Stanley also argues that the penalty clause is too severe. Mr. Stanley argues that since the rate is experimental and it will require time to work out the procedures that govern communications, record-keeping and other logistics, the penalty is inappropriate. He recommends that a two-tiered penalty clause be instituted, whereby the first time a customer refuses to interrupt he is assessed a lesser penalty (such as two times the firm rate for one month) and that the second time the penalty should be raised. Ms. Taylor testified that the penalty clause was determined by a survey of several such rates in Texas, and an intention that it act as a deterrent to non-compliance. The examiner finds that the penalty must be severe enough to act as a deterrent and that Mr. Stanley's recommendation would not be sufficient to retard non-compliance. The examiner, therefore, recommends acceptance of the penalty clause as originally suggested by LCRA.

TIEC/SMI further argues that since LCRA will have the option to change the rate or seek to have it deleted altogether, customers signing up should be allowed some flexibility with respect to discontinuing or seeking to change it if it does not work. TIEC/SMI suggests that the rates should provide an option for customers to discontinue it if LCRA changes the rate. The examiner finds this to be a reasonable provision, if the change that triggers the customer's right to discontinue is limited to an increase in the rate.

With the modifications indicated above, the examiner recommends acceptance of the proposed experimental interruptible rider to the wholesale tariff.

X. Transmission Voltage Levels

BEC has proposed that the transmission (138kv) and subtransmission (69kv) voltage levels be collapsed into a single transmission level for purposes of rate design. The result of this change would be to increase the 138kv delivery system charge and loss factors and to decrease the 69kv delivery system charge and loss factors. BEC witness Foreman performed a megawatt mile computation in order to analyze the use of LCRA's transmission system. He found that internal and external changes to LCRA's system impacted the entire system regardless of voltage level. He concluded from this that the 138kv and 69kv systems are functionally the same, inasmuch as both provide system bulk power capabilities and wholesale power to the load attached to each system. He further found that the 69kv system provides an emergency backup to portions of the 138kv system. He concluded that there was no reason to separate the systems with a rate differential.

Mr. Foreman also testified that some customers desire to have a 138kv delivery point due to their internal system requirements, but cannot obtain a 138kv delivery point due to the geography. In other words, LCRA's 69kv line may be closer to the proposed delivery point. He believes that this results in discrimination against customers by denying them the opportunity of obtaining the lower 138kv rates. That problem would be eliminated if his recommendation of combining the 69kv and 138kv rates into a single transmission delivery system charge were adopted. His proposed charges are reflected in Attachment VII.

If his recommendation of consolidation of the two voltage levels into a single transmission voltage level is accepted, it would require a recalculation of the loss factors. By way of explanation of losses, he testified that wires carrying electrical current consume current by converting some of it into heat. A fifteen percent loss can also be expressed as a loss factor (1 -losses) of .85. The electric utility must generate sufficient power to supply its customers, including the losses. The utility can only charge the customer for the power consumed however, and therefore rates are usually set which allow the electric utility to allocate the costs of the losses to the consumer based upon loss factors. Different voltage level rate classes do have different loss factors, a fact which is also recognized in the rates. The losses for each voltage level is determined by the class's proximity to the source of power. Mr. Foreman testified that transmission customers (138 and 69 kv) are metered on the high voltage side of the power transformer whereas the distribution class is metered on the low voltage side of the transformer. Thus the difference in generation requirements to serve the transmission and distribution classes is attributable in part to the losses which occur in the transformer. From the distribution metering point, electric current flows through the wires of the distribution system across another transformer and down a service wire before reaching the customer's meter. That customer's metering point may be physically distant from the source of power as well as electrically distant from the source of power. The end-use consumer is served at .6kv which is 115 times lower than 69kv. Mr. Foreman testified that power consumption at lower voltage levels causes much higher losses than transmission at higher voltages.

Mr. Foreman calculated the loss factors for each LCRA voltage level rate class based upon the power requirements, sales at meters and the difference in losses between voltage level rate classes. Mr. Foreman believes that LCRA's proposed loss factors inaccurately assume that the power received by the primary rate class must flow sequentially through the entire 345kv, 138kv, and 69kv transmission grid. Based upon his megawatt mile analysis he believes that the power in fact is comingled and does not flow sequentially from high voltage to low voltage. His calculation of actual losses between his collapsed transmission class and the primary class is only 0.61 percent, whereas LCRA has a loss differential of 3.08 percent for energy and 3.4 percent for demand.

Mr. Foreman undertook an analysis to show that LCRA's loss differentials result in inaccurate price signals. He compared a wholesale customer constructing a substation and taking delivery at 69kv or 138kv, versus letting

LCRA build the substation and taking delivery at 12.5kv. The results show that a complete substation could be paid for in 4.5 years at 138kv but would require 17.9 years at 69kv due to the rate savings caused by the inaccurate loss differentials. He further found that the increased costs of building a 138kv substation versus a 69kv substation can be recovered in only 1.3 years. He concluded that a 4.5 year payback on equipment with a 30 to 35-year life is indicative of non-cost based rates.

Two different rate impacts are associated with a customer's voltage level, including the delivery system charge and the voltage level loss factors used to adjust all other charges (capacity, fuel and energy). The delivery system charge is designed to recognize the difference in capital requirements for LCRA to build a transmission delivery point, with the customer owning the substation, versus a primary delivery point, where LCRA owns the substation. This charge is lower for transmission level customers than for primary customers, in order to reflect the cost savings to LCRA and the cost of ownership incurred by the consumer. Mr. Foreman was not proposing a change to the structure of that component for voltage level rates other than to combine the 138kv and 69kv charges. With respect to the capacity, base energy, and fuel charges, which are designed to recognize the difference in losses required to serve each voltage level rate class he concluded that the primary class should be charged an amount equal to 0.61 percent more than the transmission rate. Mr. Foreman's recommendation is that the delivery system charges for LCRA should be $0.872/kw for the consolidated transmission class and $1.189/kw for the primary class. He also proposes that loss factors applicable to the other charges should be instituted as follows:

Rate Class	Demand	Energy
Transmission	0.95397	0.95944
Primary	0.94787	0.95334
Secondary	0.87367	0.87734
Average	0.94982	0.95580

Most of the intervenors oppose BEC's proposal to collapse the transmission classes into a single transmission group. LCRA did not present any rebuttal on this issue and does not address it in its briefs. LCRA has created a

Transmission Task Force (TTF) which is looking into several issues relating to the voltage differential. One of the subcommittees of that task force, the losses transmission subcommittee, is chaired by David Peterson, who is BEC's engineer. That subcommittee submitted a position statement to the TTF in May 1988, which Mr. Foreman relied on. The recommendation of the losses subcommittee of the transmission task force is that losses should be categorized in two voltage levels, including distribution of 60kv and below, and transmission of above 60 kv. LCRA witness Lee, who is LCRA's representative on the subcommittee, testified that the purpose of the subcommittee was to study the engineering aspects of losses and not the issues relating to the collapse of the voltage differentials.

LCRA witness Taylor presented prefiled testimony in which she indicated that the RDTF determined that the current voltage differentials would be maintained pending a recommendation from the entire TTF. Ms. Taylor identified the issues to be addressed in this area as the inaccessibility of some customers to 138kv service and the savings to be derived by customers who are able to purchase 138kv transformation facilities. Her testimony reflects that the 138kv delivery system charge does not include any of the costs of the 69kv system under the existing differential system. She concedes that the 69kv transmission system is believed to benefit all LCRA customers because the 69kv system connects the hydro facilities to the transmission network and the 69kv system provides backup reliability to the 138kv system. She further concedes that the current loss percentages between the 138kv and distribution rates are approximately 3.25 percent, whereas current estimates of losses over the transformation facilities show them to be only 0.5 - 1 percent. On the other hand, Ms. Taylor points out that customers who own transmission lines contend that the benefit which they provide to the system has not been recognized and in fact the 138kv and 12.5kv differential should be larger to recognize the benefits these customers claim their transmission systems provide. She notes that LCRA and its customers are also considering the possibility of purchasing wholesale customer transmission facilities integral to the LCRA system if the purchase is determined to be in the best long-term interest of the ultimate consumers. The customers estimated the value of their own systems as $43.5 million. BEC Exhibit 5. The largest system is PEC's, valued at $18 million, followed by GVEC and PEC with systems valued at $6.6 million each. Included in the estimate are systems owned by New

Braunfels, San Bernard Electric Coop, Bandera Electric Cooperative, McCullough County Electric Cooperative, Central Texas Electric Cooperative, Dewitt County Electric Cooperative and the City of Seguin.

Originally, all of LCRA's customers had radial transmission systems, but as their loads grew their systems began to connect with LCRA at more than one location. The customers therefore received the benefit of looped service and LCRA does not charge them for multiple points of delivery. In exchange, LCRA does not pay wheeling charges to their customers for use of their transmission systems. Mr. Foreman agreed that if his proposal is accepted, another means of compensating customers whose transmission facilities are used by LCRA must be found. He contends that compensation should not be related to the voltage collapse issue. It is obvious however that the two issues are tied together at this time and the examiner finds that he has failed to explain persuasively how they can be separated and only one of them dealt with at this time, as he suggests.

Mr. Stanley, who is an engineer, worked on a consulting basis with LCRA beginning in 1976 and participated in several rate cases. He testified that LCRA's system is designed to flow power from higher to lower voltage, although it can flow the other way. He does not believe the voltage systems should be collapsed, because the existing differential compensates those customers who have invested in 138kv transmission systems for LCRA's occasional use of the systems for transfer.

Based upon the credible testimony of Mr. Foreman and several of LCRA's witnesses who are engineers, the examiner is persuaded that the distinction in the rates between the 138kv and 69kv systems is not technically supportable. The engineers agreed that electricity flows from the greatest strength to the greatest demand, in other words along the path of least resistance, and that loads change constantly as the loads shift. What is not clear to the examiner is how the engineering realities should be addressed in the rates. Some parties argued that the issue is not whether the 138kv and 69kv systems impact each other but which supports which. PEC witness Goble, who is not an engineer, contends that the 138kv system supports the 69kv system and not vice versa. It also appears that on average losses on 138kv systems are lower than on 69kv system and the per kW cost of construction is less for 138kv lines than for 69kv lines. Although the examiner is not persuaded by arguments advanced by parties that this issue should be delayed because it is being studied by the TTF, the examiner is persuaded that there are related issues that directly impact the rate design with respect to voltage levels which were not fully developed in this record. The examiner therefore recommends that LCRA be ordered to present in its next rate case an analysis of all issues related to the voltage differentials. The examiner is also uncertain what impact Mr. Foreman's proposed change in loss factors would have on the stipulated fixed fuel factor since the fuel revenues were also stipulated. In other words, it seems to the examiner that there would be a difficulty with maintaining that portion of the stipulation and changing the loss factors. The examiner trusts that BEC will brief this point in its exceptions.

XI. Summary of Recommendation

Although the revenue requirement portion of this application was resolved through stipulation of all parties, the cost allocation and rate design issues were fully litigated during ten full days of hearing . The probability of dispatch methodology advanced by LCRA, and supported in alternate proposals by PEC and BEC, is a complex means of addressing a complex issue. The method allows the energy considerations, which are part of the generating planning and operating process, to be incorporated in the rate design process. The examiner has recommended adoption of the POD method, limiting its impact on production revenue requirement to 32%, as proposed by LCRA. The recommendation also includes acceptance of seasonal capacity and energy charges. The examiner concluded that creation of a time differentiated energy charge is not warranted at this time, but LCRA should address this issue in its next rate case. Similarly, concerns about the voltage differential in the rate structure and the retail rate structure need to be addressed in LCRA's next application for a rate increase.

XII. Findings of Fact and Conclusions of Law

The examiner recommends that the Commission adopt the following Findings of Fact and Conclusions of Law.

A. Findings of Fact

1. On March 14, 1988, the Lower Colorado River Authority (LCRA) filed an application to increase its retail and wholesale rates in the unincorporated areas in which it serves.

2. LCRA's application was based on a test year ending September 30, 1987.

3. On March 17, 1988, the implementation of the proposed rates was suspended for 150 days beyond their otherwise effective date of April 18, 1988, until September 15, 1988. On June 24, 1988, LCRA agreed to extend its effective date to April 25, 1988. The hearing was held over 16 days, and therefore, the 150-day suspension period was extended two additional days. The suspension period extends until September 24, 1988, or until superseding order of the Commission.

4. LCRA published notice of this application once a week for four consecutive weeks, in newspapers of general circulation in the counties affected by the proposed change, prior to the original effective date of April 18, 1988. Copies of the application, consisting of the statement of intent and rate filing package, were delivered to all of LCRA's wholesale customers, and individual notice of the application was mailed to all of LCRA's customers and to the County Commissioner's Court of each county which will be affected by the proposed rate change.

5. The hearing on the merits was convened as scheduled on June 20, 1988, and was adjourned on July 19, 1988.

6. LCRA is an agency of the State of Texas which generates and sells electricity to 31 municipally owned electric utilities, 11 rural electric cooperatives, and 75 retail customers.

7. The net dependable generating capacity of LCRA's plants in service at the end of the test year totalled 1,836 megawatts (MW).

8. LCRA's third coal fired plant, Fayette Power Plant Unit 3, achieved commercial operation on April 29, 1988.

9. The parties stipulated to the revenue requirement portion of the application, as discussed in Section IV.A. of this Examiner's Report.

10. An overall annual revenue requirement of $284,631,546, the components of which are shown below, and a base rate revenue requirement of $146,480,737, will permit LCRA to recover its reasonable and necessary operating expenses, as discussed in Section IV of this Examiner's Report:

Fuel	$108,506,160
Operations & Maintenance	58,808,630
Depreciation	17,068,426
Return	100,248,330
Revenue Requirement	$284,631,546
Other revenues	$ 29,644,649
Fuel revenues	108,506,160
Base Rate Revenues	$146,480,737
Overall Percent Increase	9.21%

11. LCRA's known or reasonably predictable reconcilable fuel expense is $108,506,160.

12. LCRA's total adjusted kWh sales are 6,934,125,097 kWh.

13. LCRA's system fixed fuel factor should be set at $0.01584/kWh, as discussed in Section IV-B.2 of this Examiner's Report.

14. LCRA's over/underrecovery of fuel costs has been finally reconciled for the period from July 1987 through March 1988, as discussed in Section IV-B.1 of this Examiner's Report.

15. An overall operations and maintenance (O&M) expense of $58,808,630, based on the adjustments to test year O&M reflected below, are reasonable for the reasons discussed in Section IV-C of this Examiner's Report:

Test Year O&M		$60,382,921
Increases:		
Coal Handling	$6,915,711	
FPP 3 Railcar Lease	890,000*	
Lake Make Up	15,718*	
CP&L Power Bill	237,776	
Incentive Retirement Program	922,072	
FPP 3 Payroll	7,495,300*	
TOTAL INCREASES		$16,476,577
Decreases:		
Water and Environmental	$8,061,293	
Allocated Water & Environmental	1,988,591	
Cooling Efficiency	1,583,638	
Franchise Requirements	258,839	
Retail O&M	3,225,617	
Purchased Power	2,932,890	
TOTAL DECREASES		($18,050,868)
PRO FORMA O&M		$58,808,630

* Reduced pursuant to stipulation.

16. LCRA has a reasonable and necessary annual depreciation expense of $17,068,426, as discussed in Section IV-D of this Examiner's Report.

17. Staff witness Keith Rogas' recommendations that LCRA be required to update its production plant depreciation rates and expenses, and perform a depreciation study for its transmission, distribution and general plant, discussed in Section IV-D of this Examiner's Report, are reasonable and should be adopted.

18. LCRA's total invested capital is $527,183,457, the components of which are as follows:

Plant in Service	$641,374,643
Accumulated Depreciation	(178,789,659)
Net Plant in Service	462,584,984
CWIP	0
Working Capital	48,039,787
Capitalized Conservation Programs	534,955
Contributed Capital	(2,564,323)
Deferred Charges	18,588,054
TOTAL INVESTED CAPITAL	$527,183,457

19. The inclusion of CWIP is not necessary to the financial integrity of LCRA, as discussed in Section IV-E of this Examiner's Report.

20. A return of $100,248,330 will permit LCRA a reasonable return on its invested capital used and useful in rendering service to the public, as discussed in Section IV-E of the Examiner's Report.

21. LCRA's base rate revenues are offset by other revenues totalling $29,644,649, as discussed in Section IV-F of this Examiner's Report.

22. LCRA's quality of service, quality of management, and energy efficiency efforts are adequate and no adjustment to its rate of return based upon these considerations should be made, as discussed in Section V of this Examiner's Report.

23. LCRA's current cost allocation and rate design methodology fails to recognize that specific generation investments result in part from the price, availability and diversity of fuels on the system.

24. LCRA's current rate design allows some customers to avoid the system peak, thereby avoiding LCRA's coincident peak (CP) charges, and thus avoid contributing to the capital costs of generating units and placing those costs on other customers.

25. LCRA's current summer and winter demand ratchet sends an incorrect price signal.

26. It is unreasonable for LCRA to continue allocating production costs entirely to capacity when its capacity charge has increased by 227% and its energy charge has decreased by 12% during the same time frame; there are excess reserves on the ERCOT system available to LCRA; its avoided capacity cost is projected to be $0; it will not need additional generation capacity for 8 to 12 years; and it has recently added a large base load unit.

27. LCRA has almost equal summer and winter peak loads during years of cold weather.

28. LCRA builds new capacity to lower its fuel costs, as well as to meet its capacity needs.

29. LCRA's customers have varying load shapes, as discussed in Section VI-A.4 of this Examiner's Report.

39. The ability of LCRA to generate electricity with its hydro units depends on the availability of water, which is dependent on weather and downstream demands.

31. LCRA plans additional capacity based on its summer peak loads.

32. LCRA does not plan additional capacity on its winter peak because of the availability of excess capacity in the ERCOT system at a price substantially below LCRA's cost of capacity.

33. The probability of dispatch (POD) methodology of allocating production capacity costs assigns costs to the hours in which generating units are dispatched, and has the flexibility to recognize operational characteristics that deviate from strict economic dispatch.

34. LCRA's interpretation of the POD results in the classification of production capital costs between demand and energy and the allocation of production capital and fuel costs to seasons of the year.

35. LCRA's peaker proxy modification to the POD method reassigns a portion of the energy-related costs to demand in recognition of those units' contributions to reliability and energy concerns.

36. The POD method properly allocates a larger percentage of capacity charges to the four summer months, June through September, the period which determines LCRA's capacity requirements.

37. The POD method properly balances the allocation of high capital costs with lower fuel costs, resulting in a seasonal energy charge.

38. LCRA's existing allocation methodology classifies no production plant investment to energy and results in 20% of production revenue requirement in the energy charge.

39. The POD methodologies presented in this case result in the percentage of production plant classified as energy-related ranging from 27% to 43%, and the percentage of production revenue requirement in the energy charge ranging from 36% to 47%.

40. Based on principles of gradualism, it is reasonable to moderate the results of the classification and allocation so that no more than 32% of production revenue requirement is recovered in the energy charge. LCRA should design its rates based on this allocation.

41. Under an allocation of 32% production revenue in energy, LCRA's customers will experience increases relative to the system average ranging from 1.23x to 0.87x.

42. LCRA's capacity and base energy charges should contain a summer (June-September), winter (December-February) and off-peak (March-May and October-November) differential, as discussed in Section VI-B.4 of this Examiner's Report.

43. The POD method advocated by LCRA results in cost-based rates that accurately reflect the trade-off between high capital cost baseload units and lower fuel costs utilized by those units.

44. The POD methodology advocated by LCRA results in a price signal that more accurately reflects LCRA's cost of peaking units thereby allowing customers to make informed decisions concerning conservation and load management.

45. GVEC's proposed cost allocation would exaggerate existing inequities in costs assigned to customers by increasing the rates more for customers who are currently paying more and is therefore unreasonable.

46. LCRA's fuel assets are energy related, and the debt service coverage associated with them is properly classified as energy related, as discussed in Section VII-A of this Examiner's Report.

47. LCRA's fuel handling costs are properly assigned to energy, as discussed in Section VII-B of this Examiner's Report.

48. LCRA's fuel inventory should continue to be classified as energy, as discussed in Section VII-C of this Examiner's Report.

49. LCRA's debt service coverage is used to purchase assets, which constitute the rate base, and is therefore properly functionalized on the same basis as rate base, as discussed in Section VII-D of this Examiner's Report.

50. Revenues attributable to off-system sales should be classified the same as production plant, as discussed in Section VII-E of this Examiner's Report.

51. The Medium General Service and Large General Service customer costs should be calculated by assuming each class is one wholesale customer as recommended by Mr. Stanley and as discussed in Section VIII of the Examiner's Report.

52. The cost of common meters should be removed from the retail customer charge, as discussed in Section VIII of the Examiner's Report.

53. LCRA should address the issues raised by Mr. Stanley concerning retail rate design, and propose retail rates based on a cost of service study, in its next rate case.

54. LCRA should utilize the same voltage categories for its LGS retail class as it does for its wholesale class.

55. LCRA's proposed experimental rider for interruptible service, as modified by the examiner in Section IX of the Examiner's Report, should be accepted.

56. LCRA's current voltage differential between 138kv and 69kv systems is technically not supportable, but the voltage systems could not be collapsed for rate purposes without addressing other issues, including compensation of owners of 138kv systems for use of their systems, and the cost differentials attendant to construction of the systems. There is no evidence in this case showing how these other issues, which are addressed in the existing voltage differential, could be properly resolved if the voltage differential on LCRA's rates were eliminated.

B. Conclusions of Law

1. LCRA is a public utility as defined in Section 3(c) of the Public Utility Regulatory Act (PURA), Tex. Rev. Civ. Stat. Ann. art. 1446c (Vernon Supp. 1987).

2. The Commission has jurisdiction over this application pursuant to Sections 16(a), 17(e), 37 and 43(a) of PURA.

3. On March 14, 1988, LCRA filed its statement of intent to change rates in accordance with Section 43(a) of PURA.

4. LCRA has published and mailed notice of its application as required by Section 43(a) of PURA and P.U.C. PROC. R. 21.22(b).

5. Pursuant to Section 43(d) of PURA implementation of LCRA's proposed rates has been suspended through September 24, 1988.

6. LCRA has the burden of establishing a revenue deficiency under present rates, and the need for additional annual revenues to be collected under the proposed changes, pursuant to Section 40 of PURA.

7. The annual revenue, base rate revenue and return reflected in the stipulation of the parties will permit LCRA a reasonable opportunity to earn a

reasonable return on its invested capital used and useful in rendering service to the public, over and above its reasonable and necessary operating expenses, in accordance with Sections 39 and 40 of PURA.

8. The return reflected in Findings of Fact Nos. 10 and 20 is reasonably sufficient to assure confidence in the financial soundness of LCRA, and is adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties, within the meaning of P.U.C. SUBST. R. 23.21(c)(1)(A).

9. LCRA's fuel over/underrecovery was finally reconciled for the period July 1987 through March 1988 in accordance with P.U.C. SUBST. R. 23.23(b)(2)(H).

10. The rates which result from LCRA's POD method, as moderated, are just and reasonable; are not unreasonably preferential, prejudicial, or discriminatory; and are sufficient, equitable, and consistent in application to each class of consumers. PURA Section 38.

11. The rates which result from LCRA's POD method will permit LCRA a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses, in accordance with Section 39 of PURA.

12. Pursuant to PURA Sections 37, 38, 39, and 43, the Commission should authorize LCRA to increase its rates consistent with the recommendation of the examiner.

13. Acceptance of the parties' stipulation concerning revenue requirement is in the public interest. PURA Section 16(a) and Tex. Rev. Civ. Stat. Ann. art. 6252-13a, Section 13(c).

Respectfully submitted,

J. Kay Trostle

J. KAY TROSTLE
HEARINGS EXAMINER

APPROVED on this the 2d day of September 1988.

Phillip A. Holder

PHILLIP A. HOLDER
DIRECTOR OF HEARINGS

jb

ATTACHMENT I
EXAMINER'S REPORT
DOCKET NO. 8032
PAGE 1 of 23

Lower Colorado River Authority

Post Office Box 220 Austin, Texas 78767 • (512) 473-3200

June 28, 1988

HAND-DELIVERED

Ms. Hilda Rodriguez
Chief Filing Clerk
Public Utility Commission
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

Re: Docket 8032; Application of Lower Colorado River Authority for Authority to Change Rates

Dear Ms. Rodriguez:

Enclosed please find the original and fifteen copies of the Stipulation entered into by the parties in the revenue requirements portion of the above referenced docket. In addition, two extra copies have been provided which are stamped "File Copy". Please datestamp these copies and return to our office via our courier.

By copy of this correspondence and accompanying instrument all parties of record are being advised of this filing. Should you have any questions, please do not hesitate to contact me at 512/473-4099.

Sincerely yours,

Martha V. Terry
Assistant General Counsel

[redacted]

FILECOPY

CERTIFICATE OF SERVICE LIST - DOCKET NO. 8032

PUBLIC UTILITY COMMISSION	J. Kay Trostle, Hearings Examiner Public Utility Commission 7800 Shoal Creek Boulevard Suite 400N Austin, Texas 78757
	Alfred R. Herrera, Assistant General Counsel Jess Totten, Assistant General Counsel Public Utility Commission 7800 Shoal Creek Boulevard Suite 400N Austin, Texas 78757
STRUCTURAL METALS, INC. TEXAS INDUSTRIAL ENERGY CONSUMERS	Rex. D. VanMiddlesworth Mayor, Day & Caldwell 2900 Republicbank Center Houston, Texas 77002
GUADALUPE VALLEY ELECTRIC COOP	Richard C. Balough Winstead, McGuire, Sechrest & Minick 800 Capitol Center 919 Congress Avenue Austin, Texas 78701
CITY OF SAN MARCOS CITY OF KERRVILLE	Bob Kahn Sawtelle, Goode, Davidson & Troilo 114 W. 7th Street, Suite 800 Austin, Texas 78701
ASSOCIATION OF WHOLESALE CUSTOMERS	James W. Checkley, Jr. J. Alan Holman James W. Checkley, Jr. Sandra Neisser Boone Brown Maroney Rose Barber & Dye 1300 One Republic Plaza 333 Guadalupe Austin, Texas 78701
BLUEBONNET ELECTRIC COOP BANDERA ELECTRIC COOP CENTRAL TEXAS ELECTRIC COOP KIMBLE ELECTRIC COOP	Earnest Casstevens McGinnis, Lochridge & Kilgore 1300 Capitol Center 919 Congress Avenue Austin, Texas 78701

(CERTIFICATE OF SERVICE LIST - DOCKET NO. 8032)

PEDERNALES ELECTRIC COOP	Casey Wren Clark, Thomas, Winters & Newton P. O. Box 1148 Austin, Texas 78701
OFFICE OF PUBLIC UTILITY COUNSEL	C. Kingsberry Ottmers, Public Counsel Presley R. Reed, Jr., Assistant Public Counsel Office of Public Utility Counsel 8140 Mopac Westpark III, Suite 120 Austin, Texas 78759

8032:CERT.SVC

DOCKET NO. 8032

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

STIPULATION

TO THE HONORABLE PUBLIC UTILITY COMMISSION:

LOWER COLORADO RIVER AUTHORITY (LCRA), ASSOCIATION OF WHOLESALE CUSTOMERS, CITY OF SAN MARCOS AND ITS AGENT, ELECTRIC UTILITY BOARD, CITY OF KERRVILLE AND ITS AGENT, KERRVILLE PUBLIC UTILITY BOARD, GUADALUPE VALLEY ELECTRIC COOPERATIVE, INC., BLUEBONNET ELECTRIC COOPERATIVE, INC., BANDERA ELECTRIC COOPERATIVE, INC., CENTRAL TEXAS ELECTRIC COOPERATIVE, INC., KIMBLE ELECTRIC COOPERATIVE, INC., PEDERNALES ELECTRIC COOPERATIVE, INC., STRUCTURAL METALS, INC., TEXAS INDUSTRIAL ENERGY CONSUMERS, OFFICE OF PUBLIC UTILITY COUNSEL and the PUBLIC UTILITY COMMISSION GENERAL COUNSEL (Staff) file their agreement to settle the revenue requirement portion of LCRA's Application for Authority to Change Rates and request the Commission's approval thereof. The Parties would show:

1. The Parties have entered into this Stipulation in order to amicably settle the issue of the appropriate level of LCRA's revenue requirements in this docket and to avoid the substantial time, effort and expense that would be required if these matters were resolved by a hearing on the merits. The Parties agree that the entry of an order based on this Stipulation would be reasonable and in the public interest. This Stipulation is agreed to solely for the purpose of facilitating the entry of a Final Order of the Commission in this docket and is not to be

regarded as a determination of the appropriateness or correctness of any assumptions or legal principles that may be employed in calculating the revenue requirements agreed to in this Stipulation. In particular, the Parties reserve the right to contest the Findings of Fact and Conclusions of Law adopted pursuant to this Stipulation in any other proceeding before the Commission or any other government agency or court, except that the Parties are bound by this Stipulation in an action for judicial review of any decision of the Commission in this docket that is based on this Stipulation. The Parties further agree that this Stipulation shall not be offered into evidence in any such other proceeding except in an action for judicial review of any decision of the Commission in this Docket.

2. The Parties agree that the prefiled revenue requirement direct testimony and the prefiled rebuttal testimony of the following LCRA witnesses, together with those schedules from LCRA's rate filing package which those witnesses are sponsoring: William P. Freeman, Walter Reid, Stephen Bartley, Milton Lee, H. Dale Tucker, James Hamann, Vicky Langston, and Robert Hutchins, together with the prefiled revenue requirement direct testimony of all Intervenors and the Staff of the Public Utility Commission of Texas shall be offered into evidence without objection for the purpose of supporting this Stipulation of the revenue requirements portion of this Docket. LCRA agrees and stipulates to make available for cross-examination its revenue requirement witnesses in the cost allocation and rate design phase of this

proceeding.

3. The Parties agree and stipulate, subject to Paragraph 7 herein, that the Commission should, in its Final Order, set the revenue requirements of LCRA by adopting this Stipulation, including Exhibit A attached hereto and incorporated herein for all intents and purposes, together with Findings of Fact and Conclusions of Law contained in Exhibit B which is attached hereto and incorporated herein for all intents and purposes. The agreed Findings of Fact and Conclusions of Law address the revenue requirements portion of this proceeding and reflect the adjustments and revisions contained in Exhibit A. The agreed Findings of Fact and Conclusions of Law are not intended to settle, dispose of or otherwise address the appropriateness or inappropriateness of any issue regarding cost allocation and rate design including the ratemaking principles of cost allocation and rate design except as provided in Paragraph 6 herein.

4. The Parties agree that the proposed changes may become effective for electric service furnished by LCRA on and after the date of the entry of the Final Order in this Docket.

5. The Parties agree and stipulate that LCRA shall continue to capitalize the costs of its Conservation and Load Management programs as provided in Finding of Fact Number 8 in Exhibit B. This language shall not be construed as an agreement that the level of costs so capitalized by LCRA is reasonable or necessary, nor as an agreement that the level capitalized by LCRA will be collected from ratepayers in the future.

6. The Parties further agree and stipulate that the delivery point kilowatt demands (both coincident and non-coincident) used to calculate the billing determinants under the final rate design methodology adopted by the Commission in its Final Order in this proceeding should be the billing determinants used in the preparation of the rates proposed by LCRA in Docket Number 8032 and described in the prefiled Direct Testimony of Angela J. Taylor in Docket Number 8032. The delivery point kilowatt-hours ~~by delivery point~~ used to calculate the billing determinants under the final rate design methodology adopted by the Commission in its Final Order in this proceeding should be those provided in LCRA's Supplemental Response to Structural Metals, Inc.'s Fifth Request for Information, Number 98, which is attached hereto and incorporated herein as Exhibit C.

7. The Parties agree that each of them reserves the right to withdraw and demand a full public hearing at any time prior to the expiration of the period for filing motions for rehearing, in the event the Commission enters a Final Order that deviates from their Stipulation. The Parties further agree that each of them reserves the right to appeal in the event the Commission enters a Final Order that deviates from this Stipulation.

WHEREFORE, the Parties request the Commission to enter a Final Order that disposes of the revenue requirements portion of LCRA's Application by adopting their Stipulation.

Respectfully submitted,

Martha V. Terry
Assistant General Counsel
LOWER COLORADO RIVER AUTHORITY

Howard V. Fisher

Howard Fisher, Attorney for
ASSOCIATION OF WHOLESALE CUSTOMERS

Bob Kahn

BOB KAHN, Attorney for
CITY OF SAN MARCOS AND ITS AGENT,
ELECTRIC UTILITY BOARD

Bob Kahn

BOB KAHN, Attorney for
CITY OF KERRVILLE AND ITS AGENT,
KERRVILLE PUBLIC UTILITY BOARD

Richard C. Balough, Attorney for
GUADALUPE VALLEY ELECT. COOP., INC.

Earnest Casstevens

Earnest Casstevens, Attorney for
BLUEBONNET ELECTRIC COOP., INC.
BANDERA ELECTRIC COOP., INC.
CENTRAL TEXAS ELECTRIC COOP., INC.
KIMBLE ELECTRIC COOP., INC.

Casey Wren, Attorney for
PEDERNALES ELECTRIC COOP., INC.

Rex VanMiddlesworth, Attorney for
STRUCTURAL METALS, INC.

Rex VanMiddlesworth, Attorney for
TEXAS INDUSTRIAL ENERGY CONSUMERS

Presley R. Reed, Attorney for
OFFICE OF PUBLIC UTILITY COUNSEL

Jess Totten
Assistant General Counsel
PUBLIC UTILITY COMMISSION

EXHIBIT A

DESCRIPTION		
1.	Overall Cost of Service	
2.	Fuel	$108,506,160
3.	Operations and Maintenance	58,808,630
4.	Total Operating Expense	167,314,790
5.	Available for Debt Service	117,316,756
6.	Total Cost of Service	$284,631,546
7.	Revenue Requirement	
8.	Fuel Revenue	$108,506,160
9.	Other Revenues	29,644,649
10.	Base Rate Revenue	146,480,737
11.	Total Revenue Requirement	$284,631,546
12.	Overall Percent Increase	9.21%
13.	Available for Debt Service	$117,316,756
14.	Less:	
15.	Gain on Sale & Refund.	6,779,606
16.	Net Available for Debt Service	$110,537,150

EXHIBIT B
FINDINGS OF FACT

(1) LCRA is a state governmental agency furnishing electric service at wholesale and retail throughout a large portion of Central Texas.

(2) On March 14, 1988, LCRA filed a Statement of Intent to Change Rates, effective April 18, 1988, which were later suspended by the Hearing Examiner.

(3) An annual revenue increase of $21,494,302 is necessary and reasonable to permit LCRA to provide adequate and reliable electric service to its wholesale and retail customers.

(4) The annual revenue increase contained in Finding of Fact Number 3 will permit LCRA a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public.

(5) An overall annual revenue requirement of $284,631,546 will permit LCRA to recover its reasonable and necessary operating expenses, together with the return set out in Finding of Fact 4.

(6) LCRA's base rate revenue requirements are $146,480,737.

(7) LCRA's known and reasonably predictable reconcilable fuel expense and fixed fuel factor revenues are $108,506,160 using a system fuel factor of 1.584 per kwh. LCRA's over/underrecovery has been finally reconciled for the period from July, 1987, through March, 1988. LCRA has generated electricity efficiently, maintained effective cost controls, and its negotiations have produced the lowest reasonable cost of fuel to the ratepayers for the period of reconciliation.

(8) It is reasonable for the Commission to include in its Final Order the following: "LCRA shall continue to capitalize the costs of its Conservation and Load Management programs."

(9) The delivery point kilowatt demands (both coincident and non-coincident) used to calculate the billing determinants under the final rate design methodology adopted by the Commission by Final Order in this proceeding will be the billing determinants used in the preparation of the rates proposed by LCRA in its application in Docket Number 8032 and as set forth in the prefiled Direct Testimony of Angela J. Taylor. The delivery point kilowatt-hours ~~by delivery point~~ used to calculate the billing determinants under the final rate design methodology adopted by the Commission by Final Order in this proceeding should be those kilowatt hours by delivery point provided in LCRA's Supplemental Response to Structural Metals, Inc.'s Fifth Request for Information, Number 98, which is attached hereto as Exhibit C.

CW
BK

CONCLUSIONS OF LAW

(1) The Public Utility Commission of Texas has jurisdiction over LCRA's Application for Authority to Change Rates pursuant to sections 16, 17, 37, and 43 of the Public Utility Regulatory Act, Tex. Rev. Civ. Stat. Ann., art 1446c (hereinafter "Utility Act").

(2) LCRA has the burden of establishing a revenue deficiency under present rates and the additional annual revenues to be collected under the proposed changes.

(3) The return, annual revenue requirement and base rate revenue requirement set forth in Findings of Fact numbers 4, 5 and 6 hereinabove will permit LCRA a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses, in accordance with sections 39 and 40 of the Utility Act.

Lower Colorado River Authority

Post Office Box 220 Austin, Texas 78767 • (512) 473-3200

May 25, 1988

Ms. Lisa Groomes
Chief Filing Clerk
Public Utility Commission
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

Re: Docket 8032; Application of Lower Colorado River Authority for Authority to Change Rates

Dear Ms. Groomes:

Enclosed please find the original and three copies of the Supplemental Response of Lower Colorado River Authority to Structural Metals, Inc.'s Fifth Request for Information Number 98. In addition, two extra copies have been provided which are stamped "File Copy". Please datestamp these copies and return to our office via our courier.

By copy of this correspondence and accompanying instrument all parties of record are being advised of this filing. Should you have any questions, please do not hesitate to contact me at 512/473-4099.

Sincerely yours,

Martha V. Terry
Assistant General Counsel

FILE COPY

Exhibit C
p. 1 of 11

DOCKET NO. 8032

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

SUPPLEMENTAL RESPONSE OF LOWER COLORADO RIVER AUTHORITY TO STRUCTURAL METALS, INC.'S FIFTH REQUEST FOR INFORMATION NUMBER 98

TO: Mr. Rex D. VanMiddlesworth, Mayor, Day & Caldwell, 2900 Republicbank Center, Houston, Texas 77002

COMES NOW, Lower Colorado River Authority, Applicant, and makes the following attached Supplemental Response to Structural Metals, Inc.'s Fifth Request for Information Number 98.

Respectfully submitted,

THOMAS G. MASON
Acting General Counsel

LOWER COLORADO RIVER AUTHORITY
P. O. Box 220
Austin, Texas 78767

3700 Lake Austin Blvd.
Austin, Texas 78703
512/473-4099

BY: ______________________
MARTHA V. TERRY
State Bar No. 19799500
Assistant General Counsel

CERTIFICATE OF SERVICE

By execution of the foregoing signature, I, Martha V. Terry do hereby certify that a true and correct copy of the Supplemental Response of Lower Colorado River Authority to Structural Metals, Inc.'s Fifth Request for Information Number 98 was duly delivered to all parties of record by Hand-Delivery or Certified Mail, Return Receipt Requested on this the 25th day of May, 1988.

Exhibit C

DOCKET NO. 8032

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

AFFIDAVIT OF VICKY LANGSTON

STATE OF TEXAS

COUNTY OF TRAVIS

BEFORE ME, the undersigned authority, Vicky Langston, being first duly sworn, deposes and states:

"My name is Vicky Langston. I am employed by the Lower Colorado River Authority, having its principal place of business at 3700 Lake Austin Boulevard, Austin, Texas. I am over the age of twenty-one and am competent to make the following affidavit:

The attached Supplemental Answer of Lower Colorado River Authority to Structural Metals, Inc.'s Fifth Request for Information Number 98 was prepared by me or under my direct supervision, and the facts and opinions stated therein are, in my judgment and based upon my professional experience, true and correct."

Vicky C. Langston

VICKY LANGSTON

SUBSCRIBED AND SWORN TO BEFORE ME this 25th day of May, 1988.

Rosa L. R[illegible]
Notary Public, State of Texas
My Commission Expires [illegible]

Rosa L. R[illegible]

Notary Public in and for the State of Texas

Exhibit C
2.3 of 11

DOCKET NO. 8032

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

AFFIDAVIT OF STEPHEN L. BARTLEY

STATE OF TEXAS

COUNTY OF TRAVIS

BEFORE ME, the undersigned authority, Stephen L. Bartley, being first duly sworn, deposes and states:

"My name is Stephen L. Bartley. I am employed by the Lower Colorado River Authority, having its principal place of business at 3700 Lake Austin Boulevard, Austin, Texas. I am over the age of twenty-one and am competent to make the following affidavit:

The attached Supplemental Answer of Lower Colorado River Authority to Structural Metals, Inc.'s Fifth Request for Information Number 98 was prepared by me or under my direct supervision, and the facts and opinions stated therein are, in my judgment and based upon my professional experience, true and correct."

STEPHEN L. BARTLEY

SUBSCRIBED AND SWORN TO BEFORE ME this 25th day of May, 1988.

Notary Public in and for the State of Texas

Exhibit C
p. 4 of 11

DOCKET NO. 8032

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

AFFIDAVIT OF ANGELA TAYLOR

STATE OF TEXAS

COUNTY OF TRAVIS

BEFORE ME, the undersigned authority, Angela Taylor, being first duly sworn, deposes and states:

"My name is Angela Taylor. I am employed by the Lower Colorado River Authority, having its principal place of business at 3700 Lake Austin Boulevard, Austin, Texas. I am over the age of twenty-one and am competent to make the following affidavit:

The attached Supplemental Answer of Lower Colorado River Authority to Structural Metals, Inc.'s Fifth Request for Information Number 98 was prepared by me or under my direct supervision, and the facts and opinions stated therein are, in my judgment and based upon my professional experience, true and correct."

Angela J. Taylor
ANGELA TAYLOR

SUBSCRIBED AND SWORN TO BEFORE ME this 25 day of May, 1988.

ROSA L. ROHR
Notary Public, State of Texas
My Commission expires [illegible]

Rosa L. Rohr
Notary Public in and for the State of Texas

Exhibit C
p. 5 of 11

SM-98

LOWER COLORADO RIVER AUTHORITY

DOCKET NO. 8032

SMI'S FIFTH REQUEST FOR INFORMATION

SUPPLEMENTAL RESPONSE

SM-98 Referring to the apparent error described in the previous RFI, please reconcile the impact of the error on all filed schedules, including but not limited to Schedules A, O, P, and Q of the rate filing package. If new schedules must be prepared, please provide a copy of those revised schedules. If the schedules do not have to be revised, please explain why not.

ANSWER: See Attached.

PREPARER: Angela Taylor/Vicky Langston/Stephen Bartley

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ATTACHMENT I
EXAMINER'S REPORT
DOCKET NO. 8032
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Lower Colorado River Authority
Summary of Adjustments
Year Ended September 1987

Schedule 8-1
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	Unadjusted Year-End # of Customers	Adjusted Year-End # of Customers	Unadjusted Test Year KWH Sales	Kwh Sales Weather & Year-End Adjustment	Kwh Sales Customer Adjustment	Kwh Sales Other Adjustment	Adjusted KWH Sales
Residential	13,308	22	197,271,136	4,369	(197,004,002)	0	270,903
Small General Service	3,467	31	64,023,370	16,605	(63,003,262)	0	1,036,721
Medium General Service	211	4	76,730,425	12,217	(76,100,148)	0	650,494
Large General Service	25	16	207,435,007	3,145,063	(45,021,346)	0	165,558,726
Mercury Vapor Lights	1,310	2	1,140,777	33	(1,147,097)	0	1,713
Park Service	14	0	300,995	0	(300,995)	0	0
Street Lighting	69	0	1,904,770	0	(1,904,770)	0	0
Municipal Pumping	39	0	5,541,061	0	(5,541,061)	0	0
Subtotal Retail	18,443	75	554,452,369	3,178,407	(390,112,281)	0	167,518,557
Wholesale	125	120	6,248,581,025	127,675,167	390,350,348	0	6,766,606,540
TOTAL LCRA	18,568	203	6,803,033,374	130,853,656	238,067	0	6,934,125,097

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ATTACHMENT I
EXAMINER'S REPORT
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Lower Colorado River Authority
Monthly Unadjusted KWH Sales
Year Ended September 1987

	October	November	December	January	February	March	April	May	June	July	August	September	Total
Residential	27,443,307	16,169,397	14,703,860	17,073,970	17,070,724	14,140,391	14,192,423	11,030,758	11,559,745	15,412,043	17,530,399	18,627,361	197,271,136
Small General Service	9,160,621	6,145,375	4,311,206	4,416,201	4,725,039	3,846,745	4,196,167	4,400,757	4,641,531	5,531,661	6,251,236	6,160,659	64,023,370
Medium General Service													
-Secondary													
-Primary													
Subtotal	12,326,604	8,564,552	5,245,072	5,051,022	5,319,007	4,635,531	4,704,330	5,266,396	5,307,000	6,107,962	6,096,136	7,071,034	76,730,425
Large General Service													
-Primary	21,560,556	18,966,292	16,923,040	18,646,494	15,106,002	17,523,501	17,621,545	16,357,791	18,227,992	16,326,513	16,200,009	14,670,372	207,435,007
-Sub Transmission													0
Subtotal	21,560,556	18,966,292	16,023,040	18,646,494	15,106,002	17,523,501	17,621,545	16,357,791	18,227,992	16,326,513	16,200,009	14,670,372	207,435,007
Mercury Vapor Lights	120,150	117,017	88,080	88,920	91,440	89,690	90,450	90,610	90,330	90,020	90,020	91,650	1,140,777
Park Service	56,654	43,341	20,450	14,870	13,210	17,006	26,204	23,400	30,374	30,864	40,438	45,774	380,995
Street Lighting	260,790	230,990	154,160	157,090	143,130	136,006	143,003	136,119	136,012	120,479	132,517	137,490	1,904,770
Municipal Pumping	965,843	750,815	313,302	375,706	305,438	331,400	390,076	363,040	377,574	465,790	431,266	431,425	5,341,861
Subtotal Retail	71,918,535	50,996,350	41,360,150	46,646,361	43,659,050	40,722,630	41,354,270	38,556,757	40,471,450	44,185,130	47,660,821	47,204,613	554,452,349
Wholesale													
-Primary	142,077,035	125,143,266	130,585,703	147,337,344	131,416,565	110,401,315	120,106,906	136,583,531	164,050,019	189,324,702	215,137,140	178,140,350	1,806,531,252
-Sub Transmission	65,987,640	69,045,120	82,356,356	88,143,590	73,636,191	60,780,979	69,690,911	67,299,299	82,440,532	93,393,676	111,219,652	88,132,080	955,325,394
-Transmission	244,678,271	239,376,755	276,570,961	296,526,743	277,376,433	233,916,644	256,665,890	266,655,339	307,949,797	347,503,603	377,144,167	335,758,696	3,405,724,377
Subtotal	451,763,596	433,565,149	497,513,060	532,010,277	482,527,107	405,127,630	446,543,707	470,579,187	554,439,340	629,502,061	724,303,967	602,239,134	6,240,331,985
TOTAL LCRA	523,662,041	484,501,699	538,501,210	578,664,638	526,529,297	445,919,968	395,077,985	509,135,946	594,911,096	673,687,191	772,164,783	649,203,747	4,303,053,374
-Secondary	50,349,979	32,030,229	25,044,318	27,999,867	20,472,976	23,199,129	23,732,733	22,198,966	22,243,466	27,050,617	31,369,812	32,306,221	347,917,342
-Primary	163,546,391	144,109,558	154,609,503	165,903,838	146,602,847	128,975,316	145,030,451	152,791,242	182,206,011	204,651,215	232,425,157	172,346,759	2,013,966,259
-Subtransmission	65,987,696	69,045,120	82,356,356	88,143,990	73,636,191	60,783,979	69,670,911	67,299,299	82,440,532	93,393,676	111,219,652	88,132,087	955,325,394
-Transmission	249,678,971	239,395,755	276,570,961	296,526,943	277,076,433	223,916,644	256,665,090	256,655,337	307,943,797	347,503,603	377,144,167	335,758,696	3,456,724,379

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Exhibit C

ATTACHMENT I
EXAMINER'S REPORT
DOCKET NO. 8032
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Lower Colorado River Authority
Monthly Adjusted KWH Sales
Year Ended September 1987

Schedule P-1
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	October	November	December	January	February	March	April	May	June	July	August	September	Total
Residential	19,532	16,783	17,351	22,326	21,160	15,770	19,212	19,973	21,041	29,902	37,617	31,820	276,903
Small General Service	60,192	73,021	85,215	82,296	62,646	64,237	81,529	83,321	101,144	118,236	122,583	94,303	1,036,721
Medium General Service													
-Secondary	48,204	52,105	49,491	57,985	53,341	39,296	46,454	52,612	57,546	59,739	67,340	66,102	650,415
-Primary	0	2	30	39	0	5	0	0	0	3	0	0	79
Subtotal	48,204	52,107	49,521	58,024	53,341	39,301	46,454	52,612	57,546	59,742	67,340	66,102	650,494
Large General Service													
-Primary	9,305,409	9,612,784	10,436,024	14,705,442	11,358,467	12,454,399	11,066,415	9,920,013	12,100,494	8,963,833	7,951,346	7,353,948	126,230,574
-Sub Transmission	3,585,941	2,819,463	2,637,313	2,699,204	2,922,745	2,763,392	2,980,043	3,292,217	3,573,043	4,143,702	4,095,313	3,815,576	39,320,152
Subtotal	13,091,350	12,432,247	13,073,337	17,404,646	14,281,212	15,217,791	14,046,458	13,212,230	15,673,537	13,107,535	12,646,959	11,171,524	165,550,726
Mercury Vapor Lights	105	142	140	130	154	130	140	139	146	144	136	143	1,713
Park Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Street Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0
Municipal Pumping	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Retail	13,227,423	12,572,390	13,225,564	17,567,442	14,410,719	15,337,241	14,993,793	13,368,275	15,853,814	13,315,559	12,274,535	11,363,872	167,510,557
Wholesale													
-Primary	147,347,600	127,304,329	130,952,586	157,509,815	144,125,990	105,479,644	128,059,708	135,633,630	171,507,004	193,704,461	209,297,034	181,784,064	1,040,708,852
-Sub Transmission	73,767,670	72,179,385	84,757,493	96,753,574	83,087,435	59,755,184	71,725,917	68,977,440	88,973,784	99,545,704	111,261,489	92,682,030	1,003,444,927
-Transmission	299,143,257	268,060,100	396,410,300	351,254,651	335,390,445	245,393,727	292,176,909	288,283,311	351,807,130	391,607,466	420,311,034	372,422,339	3,722,372,761
Subtotal	520,258,535	467,543,813	530,120,407	605,515,040	562,493,070	410,628,555	491,964,584	492,894,389	612,369,990	684,857,671	741,070,357	646,899,233	6,766,606,540
TOTAL LCRA	533,485,958	480,116,113	543,346,051	623,082,482	576,912,597	425,965,796	506,958,377	506,262,664	628,223,012	698,173,230	753,344,092	658,253,125	6,934,125,097
-Secondary	136,073	140,853	152,227	162,796	137,507	119,450	147,335	156,045	180,277	200,024	227,676	192,360	1,959,831
-Primary	300,640,646	136,917,100	149,300,710	172,215,257	155,404,465	117,734,043	139,926,123	145,553,643	183,687,570	202,668,290	217,849,100	189,140,012	1,967,019,426
-Subtransmission	77,533,615	74,990,760	87,374,006	99,449,770	85,990,180	62,518,576	74,706,010	72,267,665	92,546,827	103,689,446	115,357,002	96,498,406	1,042,773,079
-Transmission	299,143,257	268,060,100	396,410,300	351,254,651	335,390,445	245,393,727	292,178,909	288,283,311	351,807,130	391,607,446	420,311,034	372,422,339	3,922,372,761

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ATTACHMENT I
EXAMINER'S REPORT
DOCKET NO. 8032
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Lower Colorado River Authority
Monthly Adjustment to kWh Sales
Year Ended September 1987

Schedule D-1
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	October	November	December	January	February	March	April	May	June	July	August	September	Total
Residential	(27,423,775)	(16,154,564)	(14,686,309)	(17,053,652)	(17,053,556)	(14,124,013)	(14,083,211)	(11,810,385)	(11,538,304)	(15,303,141)	(17,492,782)	(18,595,541)	(197,000,233)
Small General Service	(9,100,429)	(6,072,374)	(4,926,071)	(4,333,985)	(4,662,395)	(3,782,900)	(4,114,630)	(4,405,436)	(4,540,387)	(5,413,425)	(6,128,623)	(6,006,356)	(62,986,627)
Medium General Service													
-Secondary													
-Primary													
Subtotal	(12,270,400)	(8,312,446)	(5,195,571)	(4,992,998)	(5,266,146)	(4,596,230)	(4,737,876)	(5,213,982)	(5,329,234)	(6,130,220)	(6,828,776)	(7,005,732)	(76,087,931)
Large General Service													
-Primary													
-Sub Transmission													
Subtotal	(8,477,806)	(6,334,045)	(2,950,503)	(1,241,040)	(904,870)	(2,305,710)	(2,775,087)	(3,145,361)	(2,534,455)	(3,218,970)	(4,241,150)	(3,526,860)	(41,876,281)
Mercury Vapor Lights	(120,005)	(117,675)	(87,940)	(88,770)	(91,286)	(89,556)	(90,310)	(90,471)	(90,184)	(90,676)	(90,604)	(91,307)	(1,147,064)
Park Service	(56,664)	(43,341)	(20,450)	(14,870)	(13,510)	(19,006)	(26,204)	(23,400)	(30,374)	(38,064)	(40,430)	(45,794)	(388,975)
Street Lighting	(260,790)	(230,990)	(154,168)	(157,090)	(143,130)	(136,006)	(143,083)	(136,119)	(136,012)	(120,479)	(132,317)	(137,490)	(1,904,770)
Municipal Pumping	(963,043)	(750,815)	(313,302)	(375,706)	(305,430)	(331,400)	(370,076)	(363,040)	(397,594)	(465,780)	(431,266)	(438,425)	(5,341,861)
Subtotal Retail	(58,691,112)	(38,424,250)	(27,842,394)	(29,070,919)	(29,240,339)	(25,385,309)	(26,360,485)	(25,180,482)	(24,617,644)	(30,869,571)	(35,394,286)	(35,840,721)	(386,933,792)
Wholesale													
-Primary	157,065,422	2,161,058	366,943	10,172,471	12,707,433	(5,002,171)	(127,190)	(999,921)	7,531,065	5,379,759	(6,037,310)	3,635,706	186,053,253
-Sub Transmission	4,786,074	3,134,177	2,401,137	8,606,584	9,431,244	(1,033,795)	2,035,056	1,687,149	6,333,252	5,952,060	41,037	4,550,750	48,119,333
-Transmission	58,465,186	28,663,487	29,839,347	54,717,708	57,424,012	11,477,083	25,313,019	21,627,972	43,066,333	44,923,703	23,386,067	36,663,643	435,648,302
Subtotal	60,315,027	33,958,604	32,607,427	73,496,763	79,564,689	5,441,117	27,420,877	22,315,200	57,930,650	55,355,610	16,389,390	44,850,099	518,025,515
TOTAL LCRA	9,823,917	(4,465,586)	4,764,833	44,417,844	50,324,350	(19,944,272)	1,063,392	(2,873,282)	33,313,006	24,486,039	(18,824,896)	9,009,378	131,091,723

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Previous Average Energy = .006141 ¢/kwh
New Average Energy = .006166 ¢/kWh

Difference = .000025 ¢/kWh

SCHEDULE 1

RATE YEAR FUEL PRICE FORECAST ($/MMBtu Delivered)

MONTH/YEAR	NATURAL GAS	ARCO CONTRACT COAL	SPOT COAL	POWELL BEND LIGNITE	#2 FUEL OIL
OCTOBER 1988	$1.810	$1.998	$1.279	$0.749	$3.650
NOVEMBER 1988	$1.910	$1.998	$1.279	$0.749	$3.650
DECEMBER 1988	$2.060	$1.998	$1.279	$0.749	$3.650
JANUARY 1989	$2.210	$2.007	$1.279	$0.783	$3.650
FEBRUARY 1989	$2.210	$2.007	$1.279	$0.783	$3.650
MARCH 1989	$2.160	$2.007	$1.279	$0.783	$3.650
APRIL 1989	$2.110	$2.015	$1.279	$0.783	$3.650
MAY 1989	$2.060	$2.015	$1.279	$0.783	$3.650
JUNE 1989	$1.960	$2.015	$1.279	$0.783	$3.650
JULY 1989	$1.960	$2.024	$1.279	$0.783	$3.650
AUGUST 1989	$1.960	$2.024	$1.279	$0.783	$3.650
SEPTEMBER 1989	$2.010	$2.024	$1.279	$0.783	$3.650

January Dispatch Levels

Unit	Capability	Effective Continuous Rating(%)	Effective Continuous Rating(MW)	Dispatch Level
Hydro	8.1	100.00%	8.1	0.0
FPP-1	297.5	83.34%	247.9	8.1
FPP-2	282.5	87.01%	245.8	256.1
FPP-3	416.0	80.42%	334.5	501.9
Gideon 3	330.0	82.68%	272.8	836.4
Ferguson	425.0	75.77%	322.0	1109.2
Gideon 2	135.0	78.48%	105.9	1431.3
Gideon 1	135.0	78.07%	105.4	1537.2

Febuary Dispatch Levels

Unit	Capability	Effective Continuous Rating(%)	Effective Continuous Rating(MW)	Dispatch Level
Hydro	9.5	100.00%	9.5	0.0
FPP-1	297.5	83.34%	247.9	9.5
FPP-2	282.5	87.01%	245.8	257.5
FPP-3	416.0	80.42%	334.5	503.3
Gideon 3	330.0	82.68%	272.8	837.8
Ferguson	425.0	75.77%	322.0	1110.6
Gideon 2	135.0	78.48%	105.9	1432.7
Gideon 1	135.0	78.07%	105.4	1538.6

Rates and Tarriffs Department

THE LOWER COLORADO RIVER AUTHORITY
PROBABILITY OF DISPATCH STUDY YEARS 1984-1987
FPP1 - PROBABILITIES

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
THRESHOLD LEVEL	8.1	9.5	16.4	24.8	38.1	63.4	47.9	41.8	44.0	36.0	4.0	7.6
WEEKDAY												
1	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
2	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99999
3	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99998
4	1.00000	.99998	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99997
5	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99997
6	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99997
7	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99998
8	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
9	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
10	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
11	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
12	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
13	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
15	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
16	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
17	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
18	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
19	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
20	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
21	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
22	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
23	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
24	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
WEEKEND												
1	1.00000	.99977	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
2	1.00000	.99974	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
3	1.00000	.99948	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99998
4	1.00000	.99938	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99997
5	1.00000	.99933	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99996
6	1.00000	.99935	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99995
7	1.00000	.99954	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99996
8	1.00000	.99973	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.99998
9	1.00000	.99993	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
10	1.00000	.99998	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
11	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
12	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
13	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
14	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
15	.99999	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
16	.99998	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
17	.99998	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
18	1.00000	.99999	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
19	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
20	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
21	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
22	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
23	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
24	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000

ATTACHMENT IV
EXAMINER'S REPORT
DOCKET NOL 8032

THE LOWER COLORADO [illegible]ER AUTHORITY
PROBABILITY OF DISPATCH [illegible]DY YEARS 1984-1987
FPP1 - UNITIZED PROBABILITIES

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
THRESHOLD LEVEL	8.1	9.6	16.4	24.8	38.1	63.4	47.9	41.8	44.0	36.0	4.0	7.6
WEEKDAY												
1	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
2	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
3	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
4	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
5	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
6	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
7	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
8	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
9	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
10	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
11	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
12	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
13	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
14	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
15	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
16	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
17	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
18	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
19	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
20	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
21	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
22	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
23	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
24	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
WEEKEND												
1	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
2	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
3	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
4	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
5	.00174	.00173	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
6	.00174	.00173	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
7	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
8	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
9	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
10	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
11	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
12	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
13	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
14	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
15	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
16	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
17	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
18	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
19	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
20	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
21	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
22	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
23	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174
24	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174	.00174

ATTACHMENT V
EXAMINER'S REPORT
DOCKET NO. 8032

THE LOWER COLORADO RIVER AUTHORITY - 28-Mar-88

METHOD USED TO DETERMINE BASELOAD PERCENTAGE TO ENERGY APPLIED TO BOOKED COST

	(1) CURRENT COST	(2) MINIMUM UNITIZED PROBABILITIES	(3) MINIMUM ENERGY $ PER HOUR (1)*(2)	(4) TOTAL HOURS	(5) MINIMUM ENERGY $ TOTAL (3)*(4)	(6) PERCENT OF TOTAL TO ENERGY (5)/(1)	(7) BASELOAD TO DEMAND KW * 300 $/KW	(8) BASELOAD CONTRIBUTION TO DEMAND (7)*(6)	(9) BASELOAD TO ENERGY TOTAL (5)-(8)	(10) PERCENT TO ENERGY TOTAL (9)/(1)
HYDRO	$36,210,132	0.00174	$63,006	576	$36,291,242	100.2%	$8,541,569	$8,560,702	$27,730,540	76.6%
FPP1	$177,607,316	0.00173	$307,261	576	$176,982,138	99.6%	$73,757,022	$73,497,398	$103,484,741	58.3%
FPP2	$110,176,047	0.00168	$185,096	576	$106,615,157	96.8%	$73,741,079	$71,357,768	$35,257,389	32.0%
FPP3	$425,452,000	0.00046	$195,708	576	$112,727,762	26.5%	$100,359,416	$26,591,231	$86,136,531	20.2%
GIDEON 3	$66,086,022	0.00000	$0	576	$0	0.0%	$0	$0	$0	0.0%
FERGUSON	$103,620,707	0.00000	$0	576	$0	0.0%	$0	$0	$0	0.0%
GIDEON 2	$36,154,046	0.00000	$0	576	$0	0.0%	$0	$0	$0	0.0%
GIDEON 1	$58,543,253	0.00000	$0	576	$0	0.0%	$0	$0	$0	0.0%

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NOTE *** TOTALS MAY NOT ADD UP DUE TO ROUNDING

	(11) BOOKED COST	(12) PERCENT TO ENERGY TOTAL (10)	(13) BASELOAD TO ENERGY TOTAL (11)*(12)	(14) MINIMUM ENERGY $ PER HOUR (13)/576
HYDRO	$36,970,345	76.6%	$28,312,729	$49,154
FPP1	$124,125,304	58.3%	$72,322,893	$125,561
FPP2	$102,702,761	32.0%	$32,865,866	$57,059
FPP3	$425,452,000	20.2%	$86,136,531	$149,543
GIDEON 3	$28,347,655	0.0%	$0	$0
FERGUSON	$58,295,587	0.0%	$0	$0
GIDEON 2	$12,673,197	0.0%	$0	$0
GIDEON 1	$12,400,589	0.0%	$0	$0

ATTACHMENT A-1
EXAMINER'S REPORT
DOCKET NO. 8032

PEC METHOD USED TO DETERMINE BASELOAD PERCENTAGE TO ENERGY

	(1) PEC HYDRO ALTERNATIVE CURRENT COST	(2) BASELOAD TOTAL $	(3) BASELOAD PERCENT OF TOTAL	(4) BASELOAD PLT RELIABILITY KW * $300/KW	(5) BASELOAD PLT CONTRIBUTION TO ENERGY (2)-(4)	(6) ENERGY % OF TOTAL (5)/(1)	(7) ENERGY PERCENT OF BASELOAD (5)/(2)	(8) RELIABILITY PERCENT OF BASELOAD (4)/(2)
HYDRO	$70,634,405	$70,631,511	100.0%	$8,541,250	$62,090,261	87.9%	87.9%	12.1%
FPP1	$187,097,175	$187,087,895	100.0%	$73,746,342	$113,341,553	60.6%	60.6%	39.4%
FPP2	$116,815,082	$116,656,774	99.9%	$73,640,068	$43,016,707	36.8%	36.9%	63.1%
FPP3	$425,452,000	$319,323,850	75.1%	$75,317,893	$244,005,956	57.4%	76.4%	23.6%
GID3	$69,326,243	$4,090,359	5.9%	$4,090,359	$0	0.0%	0.0%	100.0%
FERG	$107,420,377	$268,637	0.3%	$241,577	$27,060	0.0%	10.1%	89.9%
GID2	$38,078,249	$4,844	0.0%	$4,041	$802	0.0%	16.6%	83.4%
GID1	$60,642,580	$2,765	0.0%	$1,442	$1,323	0.0%	47.9%	52.1%
TOTAL	$1,075,466,111	$698,066,634	64.9%	$235,582,972	$462,483,662	43.0%	66.3%	33.7%

	(9) TOTAL CONTRIBUTION TO DEMAND	(10) SUMMER PERIOD (%)	(11) WINTER PERIOD (%)	(12) OFF-PEAK PERIOD (%)	(13) SUMMER PERIOD ($)	(14) WINTER PERIOD ($)	(15) OFF-PEAK PERIOD ($)
HYDRO	$8,544,145	33.46%	24.68%	41.87%	$2,858,502	$2,108,624	$3,577,018
FPP1	$73,755,622	33.46%	24.68%	41.86%	$24,675,327	$18,202,187	$30,877,703
FPP2	$73,798,375	33.47%	24.65%	41.88%	$24,701,224	$18,193,167	$30,904,022
FPP3	$181,446,044	35.45%	25.29%	39.26%	$64,328,320	$45,884,057	$71,233,594
GID3	$69,326,243	58.12%	27.38%	14.49%	$40,295,255	$18,983,619	$10,047,362
FERG	$107,393,317	84.93%	10.99%	4.08%	$91,214,503	$11,798,702	$4,380,198
GID2	$38,077,447	87.17%	10.13%	2.71%	$33,190,587	$3,855,638	$1,031,232
GID1	$60,641,257	99.47%	0.52%	0.02%	$60,316,952	$313,970	$10,335
					$341,580,670	$119,339,964	$152,061,464
					55.7244%	19.4688%	24.8068%

	(1) Cost Used (Current)	(2) Minimum Unitized Probability	(3) Minimum Energy $ Per Hour (1)*(2)	(4) Total Hours	(5) Minimum Energy $ Total (3)*(4)	(6) Percent of Total To Energy (5)/(1)	(7) Baseload to Demand 25.52% * (1)	(8) Baseload Contribution to Demand (7)*(6)	(9) Baseload to Energy Total (5)-(8)	(10) Percent to Energy Total (9)/(1)	(11) Current Cost	(12) Baseload to Energy Total (10)*(11)	(13) Minimum Energy $ per Hour (12)/576
Hydro	58.351.797	0.00174	101.305	576	58.351.793	100.0%	14.891.379	14.891.378	43.460.416	74.5%	58.351.797	43.460.416	75.452
FPP1	177.607.316	0.00173	307.261	576	176.982.138	99.6%	45.325.387	45.165.842	131.816.297	74.2%	177.607.316	131.784.628	228.793
FPP2	110.176.047	0.00168	185.096	576	106.615.157	96.8%	28.116.927	27.208.188	79.406.969	72.1%	110.176.047	79.436.930	137.911
FPP3	425.452.000	0.00046	195.708	576	112.727.762	26.5%	108.575.350	28.768.125	83.959.637	19.7%	425.452.000	83.814.044	145.510
Gideon 3	66.086.022	0.00000	0	576	0	0.0%	0	0	0	0.0%	66.086.022	0	0
Ferguson	103.620.707	0.00000	0	576	0	0.0%	0	0	0	0.0%	103.620.707	0	0
Gideon 2	36.154.046	0.00000	0	576	0	0.0%	0	0	0	0.0%	36.154.046	0	0
Gideon 1	58.843.253	0.00000	0	576	0	0.0%	0	0	0	0.0%	58.843.253	0	0
Total	1.035.991.188										1.035.991.188	338.496.018	

Baseload to Demand: 19% Capacity Factor / 74.44% Maximum Capacity 25.52%

Production Costs

	Dollars	Percent
Demand	697.495.170	67%
Energy	338.496.018	33%
Total	1.035.991.188	100%

Seasonal Demand Costs

	Dollars	Percent
Summer (JUN, JUL, AUG, SEP)	334.797.682	48%
Winter (JAN, FEB, DEC)	146.473.986	21%
Off-Peak (MAR, APR, MAY, OCT, NOV)	216.223.503	31%
	697.495.170	100%

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ATTACHMENT VI-C
EXAMINER'S REPORT
DOCKET NO. 8032

LOWER COLORADO RIVER AUTHORITY

COMPARISON OF INTERVENOR'S PROPOSALS FOR COST ALLOCATION AND RATE DESIGN
**** UNDER STIPULATED REVENUE REQUIREMENTS ****

	LCRA PRESENT	LCRA ALTERNATIVE	LCRA FILED OPUC & GENERAL COUNSEL	BLUEBONNET, ET AL.	PEC
OST ALLOCATION ETHOD	DOCKET NO. 7512	POD	POD	POD	POD
EMAND/ENERGY PLIT OF PRODUCTION LANT	DEMAND: 100% ENERGY: 0%	DEMAND: 75% ENERGY: 25%	DEMAND: 91.5% ENERGY: 18.5%	DEMAND: 67% ENERGY: 33%	DEMAND: 57% ENERGY: 43%
EMAND/ENERGY OF REVENUE REQUIREMENT	DEMAND: 80% ENERGY: 20%	DEMAND: 64% ENERGY: 36%	DEMAND: 68% ENERGY: 32%	DEMAND: 59% ENERGY: 41%	DEMAND: 53% ENERGY: 47%
EASONALITY	75% RATCHET	SUMMER: 46% WINTER: 23% OFF-PEAK: 31%	SUMMER: 46% WINTER: 23% OFF-PEAK: 31%	SUMMER: 48% WINTER: 21% OFF-PEAK: 31%	SUMMER: 56% WINTER: 19% OFF-PEAK: 25%
N-PEAK MONTHS	JULY-SEPT DEC,JAN,FEB	JUN-SEPT DEC,JAN,FEB	JUN-SEPT DEC,JAN,FEB	JUN-SEPT DEC,JAN,FEB	JUN-SEPT DEC,JAN,FEB
FF-PEAK MONTHS	MAR,APR,MAY JUN,OCT,NOV	MAR,APR,MAY OCT,NOV	MAR,APR,MAY OCT,NOV	MAR,APR,MAY OCT,NOV	MAR,APR,MAY OCT,NOV
OLTAGE DIFFERENTIAL	NO CHANGE	PARTIAL MOVEMENT TOWARDS VOLTAGE DIFFERENTIAL COLLAPSE	NO CHANGE	COLLAPSE VOLTAGE DIFFER. TRANSMISSION/DISTRIBUTION	NO CHANGE

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	LCRA PRESENT	LCRA ALTERNATIVE	LCRA FILED OPUC & GENERAL COUNSEL	BLUEBONNET, ET AL.	PEC
USTOMER CHARGE:	$198.0	$388.0	$388.0	$388.0	$387.0

APACITY CHARGE:	LCRA PRESENT	LCRA ALTERNATIVE SUMMER:	WINTER:	OFF-PEAK:	OPUC & GENERAL COUNSEL SUMMER:	WINTER:	OFF-PEAK:	BLUEBONNET SUMMER:	WINTER:	OFF-PEAK:	PEC SUMMER:	WINTER:	OFF-PEAK:
AVERAGE	$6.019												
138 KV	$5.933	$7.200	$4.880	$4.290	$7.590	$5.170	$4.540	$6.820	$4.010	$3.850	$6.690	$3.580	$2.970
69 KV	$6.056	$7.280	$4.930	$4.330	$7.750	$5.280	$4.630	$6.820	$4.010	$3.850	$6.830	$3.660	$3.030
12.5 <	$6.149	$7.330	$4.960	$4.360	$7.860	$5.360	$4.700	$6.860	$4.040	$3.880	$6.930	$3.710	$3.080

	LCRA PRESENT	LCRA ALTERNATIVE	LCRA FILED OPUC & GENERAL COUNSEL	BLUEBONNET, ET AL.	PEC
APACITY CHARGE PER KW-YR	$72	$65	$69	$59	$52
ELIVERY SYSTEM CHARGE:					
138 KV	$0.526	$0.684	$0.684	$0.872	$0.684
69 KV	$0.833	$1.096	$1.096	$0.872	$1.094
12.5 <	$1.047	$1.412	$1.413	$1.189	$1.411

NERGY CHARGE:	LCRA PRESENT	LCRA ALTERNATIVE SUMMER:	WINTER:	OFF-PEAK:	LCRA FILED OPUC & GENERAL COUNSEL	BLUEBONNET, ET AL.	PEC
138 KV	$0.002796	$0.006343	$0.006892	$0.005887	$0.005539	$0.007474	$0.008320
69 KV	$0.002843	$0.006397	$0.006952	$0.005938	$0.005631	$0.007474	$0.008465
12.5 <	$0.002885	$0.006444	$0.007003	$0.005982	$0.005715	$0.007520	$0.008591

EXAMINER'S REPORT
DOCKET NO. 8032
PAGE 1 of 2

LCRA 9 Rat

LOWER COLORADO RIVER AUTHORITY

COMPARISON OF INTERVENOR'S PROPOSALS FOR COST ALLOCATION AND RATE DESIGN
**** UNDER STIPULATED REVENUE REQUIREMENTS ****

	GVEC	SMI	AWC
COST ALLOCATION METHOD	ZERO-TILT	NOT POD	DOCKET NO. 7512 TO #8032
DEMAND/ENERGY SPLIT OF PRODUCTION PLANT	DEMAND:100% ENERGY: 0%	DEMAND:100% ENERGY: 0%	DEMAND:100% ENERGY: 0%
DEMAND/ENERGY % OF REVENUE REQUIREMENT	DEMAND: 91% ENERGY: 9.5%	N/R	DEMAND: 80% ENERGY: 20%
SEASONALITY	75% RATCHET	N/R	75% RATCHET
ON-PEAK MONTHS	JULY-SEPT DEC,JAN,FEB	N/R	JULY-SEPT DEC,JAN,FEB
OFF-PEAK MONTHS	MAR,APR,MAY JUN,OCT,NOV	N/R	MAR,APR,MAY JUN,OCT,NOV
VOLTAGE DIFFERENTIAL	NO CHANGE	N/R	NO CHANGE
CUSTOMER CHARGE:	$390.0	N/R	$388.0
CAPACITY CHARGE:			
AVERAGE	$7.717		$6.880
138 KV	$7.615	N/R	$6.790
69 KV	$7.771		$6.950
12.5 <	$7.891		$7.030
CAPACITY CHARGE PER KW-YR	$93	N/R	$83
DELIVERY SYSTEM CHARGE:			
138 KV	$0.684		$0.691
69 KV	$1.095	N/R	$1.100
12.5 <	$1.412		$1.417
ENERGY CHARGE:			
138 KV	$0.001652		$0.003412
69 KV	$0.001680	N/R	$0.003471
12.5 <	$0.001705		$0.003523

N/R = NO RECOMMENDATION

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Lower Colorado River Authority

COMPARISON OF REVENUES
ADJUSTED TEST YEAR 9-30-87

CUSTOMER	PRESENT	STIPULATION LCRA PROPOSED COS & RD	PERCENT	RELATIVE TO SYSTEM
BASTROP	$1,437,249	$1,593,856	10.9%	1.17
BELLEVILLE	1,443,013	1,574,327	9.1%	0.98
BOERNE	1,776,094	1,960,246	10.4%	1.11
BRENHAM	6,785,835	7,463,962	10.0%	1.07
BURNET	1,260,715	1,399,701	11.0%	1.18
CUERO	2,646,629	2,940,169	11.1%	1.19
FLATONIA	696,500	771,086	10.7%	1.15
FREDERICKSBURG	2,829,137	3,139,382	11.0%	1.18
GEORGETOWN	5,481,724	6,051,026	10.4%	1.11
GIDDINGS	1,517,325	1,682,450	10.9%	1.17
GOLDTHWAITE	542,687	604,555	11.4%	1.22
GONZALES	2,097,315	2,302,656	9.8%	1.05
HALLETSVILLE	1,000,946	1,115,983	11.5%	1.23
HEMPSTEAD	1,206,468	1,334,312	10.6%	1.14
KERRVILLE	11,599,529	12,571,223	8.4%	0.90
LAGRANGE	1,908,976	2,111,671	10.6%	1.14
LAMPASAS	2,366,360	2,619,683	10.7%	1.15
LEXINGTON	300,252	334,482	11.4%	1.22
LLANO	1,151,268	1,274,079	10.7%	1.14
LOCKHART	2,465,657	2,724,080	10.5%	1.12
LULING	1,460,631	1,620,089	10.9%	1.17
MASON	666,812	730,155	9.5%	1.02
MOULTON	323,542	355,440	9.9%	1.06
NEWBRAUNFELS	20,217,126	22,122,876	9.4%	1.01
SAN MARCOS	9,753,553	10,654,554	9.2%	0.99
SAN SABA	1,007,664	1,113,391	10.5%	1.12
SCHULENBERG	1,007,421	1,118,882	11.1%	1.19
SEQUIN	5,897,898	6,535,357	10.8%	1.16
SHINER	889,377	990,299	11.3%	1.22
SMITHVILLE	958,740	1,060,542	10.6%	1.14
WAELDER	228,673	254,406	11.3%	1.21
WEIMAR	977,645	1,089,900	11.5%	1.23
YOAKUM	1,835,583	2,042,980	11.3%	1.21
BANDERA	7,196,001	7,795,276	8.3%	0.89
BLUEBONNET	24,641,116	26,978,514	9.5%	1.02
CENTRAL TEXAS	8,059,476	8,794,823	9.1%	0.98
DEWITT	2,355,191	2,591,569	10.0%	1.08
FAYETTE	4,531,664	5,007,377	10.5%	1.13
GUADALUPE w/o SMI	13,203,575	14,384,339	8.9%	0.96
HAMILTON	1,883,932	2,078,985	10.4%	1.11
KIMBLE	899,211	987,658	9.8%	1.05
MCCULLOCH	349,302	386,637	10.7%	1.15
PEDERNALES	53,362,512	57,685,126	8.1%	0.87
SAN BERNARD	8,305,243	9,109,436	9.7%	1.04
RETAIL	5,211,074	5,757,854	10.5%	1.12
TOTAL (less SMI)	225,736,643	246,815,396	9.3%	1.00
SMI Firm		2,300,376		
TOTAL LCRA FIRM	232,402,976	249,115,773		
SMI Interuptable		4,965,075		
SMI Total	6,666,332	7,265,451	9.0%	0.96
GVEC Total	19,869,907	21,649,790	9.0%	0.96
TOTAL	$232,402,976	$254,080,848	9.3%	1.00

[redacted]

DOCKET NO. 8032

APPLICATION OF LOWER COLORADO RIVER AUTHORITY FOR AUTHORITY TO CHANGE RATES § § § JBLIC UTILITY COMMISSION OF TEXAS

ORDER

In a public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the above styled application was processed in accordance with applicable statutes by an examiner who prepared and filed a report containing findings of fact and conclusions of law. The Examiner's Report, and Supplemental Examiner's Report, are hereby ADOPTED with the following modifications and made a part of this Order.

Section VI of the Report is not adopted. Findings of Fact Nos. 23-26, 29-30, 33-45 and 56 are not adopted by the Commission. The following Findings of Fact are adopted.

56. LCRA's current voltage differential between 138 kV and 69 kV systems is technically not supportable and should be collapsed for rate purposes.

57. As was found by the Commission in Docket No. 6027, the evidence again shows that LCRA's generating plant, and in particular FPP, has been built in pursuit of fuel diversification and reduced fuel expenses as well as to meet system demand.

58. The ability to reduce peak demand is a valuable load management tool for the LCRA, as evidenced by the LCRA's own stated corporate goals and existing load management programs, which aim to shave peak usage during both the summer and the winter. Customer avoidance of peak thus does not support adoption of POD.

59. Historical increases in the demand charge do not in and of themselves justify a change in the current cost classification/allocation methodology.

[1] 60. The complexity of POD makes it inappropriate for adoption at this time.

61. No party proposing a POD-based methodology either performed or reviewed any study concerning the likely changes to the LCRA's system load characteristics or the resultant impact on generation and resource planning, and thus there is no evidence as to what impact adoption of POD may or will likely have on system load, revenues, or generation planning.

[1] 62. Significant issues as to the volatility of POD have not been fully explored and reasonably answered.

63. The POD methodology proposed by the LCRA and recommended by the Examiner allocates the cost of actual real-life generating units by comparing those costs to the costs of a hypothetical "least cost" plant that there is no evidence to show could have even been built.

64. It would be unreasonable to adopt a POD/Capital Substitution proposal that only deals with the capital costs of a plant, and not also the corresponding operating and fuel costs in an internally consistent manner, as the whole rationale undergirding POD/Capital Substitution in this case is destroyed by the lack of operating and fuel cost symmetry.

65. The LCRA's production and bulk power costs do not fluctuate with changes in energy use.

66. The LCRA's current cost of service methodology is generally logical, easily understandable, and fair, and accurately identifies the costs of serving the LCRA's customers.

[2] 67. There is no evidence of any material change in condition or factual circumstances that would warrant abandoning the current peak responsibility methodology.

68. The evidence in this case shows that a POD production plant classification/allocation methodology would not accurately identify the costs involved in serving the LCRA's customers.

69. To achieve cost-based rates, LCRA's fixed production plant and bulk power supply costs must be classified as demand-related based on this record.

The following Conclusions of Law are adopted in lieu of the correspondingly numbered conclusions recommended by the examiner:

10. Based upon Findings of Fact Nos. 57 and 67, to utilize a different production plant cost classification/allocation methodology other than the current peak responsibility methodology would be contrary to the thrust of the Supreme Court's decisions in both Texas Alarm and Signal Association v. Public Utility Commission, 603 S.W.2s 766 (Tex. 1980) and Westheimer Independent School District v. Brockette, 567 S.W.2d 780 (Tex. 1978).

11. The rate guidelines recommended by the examiner, as amended by the Commission, will result in rates that are not unreasonably preferential, prejudicial or discriminatory, but rather are sufficient, equitable and consistent in application to each class of consumers, as required by PURA Section 38.

12. Pursuant to PURA Sections 37, 38, 39 and 43, the Commission should authorize the LCRA to increase its rates consistent with the recommendations of the examiner, as amended by the Commission.

The Commission further issues the following order:

1. The application of the Lower Colorado River Authority (LCRA) is hereby GRANTED to the extent recommended in the examiner's report, and as amended by the Commission.

2. LCRA shall file five copies of its tariff, revised in accordance with this Order, and sufficient to generate revenues no greater than those prescribed in this order, with the Commission filing clerk and one copy with each of the intervenors within 20 days of the date of this Order. All parties to this docket shall have ten days from the date of that filing to file their objections, if any, to the revised tariff. Responses to objections shall be filed fifteen days after the revised tariff is filed. The tariff shall be deemed approved and shall become effective upon the expiration of 20 days after filing, or sooner upon notification of approval by the hearings division. In the event of rejection, LCRA shall have 15 additional days to file an amended tariff, with the same review procedures again to apply.

3. The revised and approved rates shall be charged only for service rendered in the areas over which this Commission is exercising its original jurisdiction, and said rates shall be charged only for service rendered after the tariff approval date. Should the tariff approval date fall within LCRA's billing period, LCRA shall be authorized to prorate each customer's bill to reflect that customer's charge, demand charge and daily energy consumption at the appropriate new rates.

4. LCRA shall perform the depreciation studies and updates recommended by staff witness Keith Rogas and discussed in Section IV-D of the Examiner's Report.

5. The revenue requirement established in this case is the result of a stipulation involving an agreement among all parties. By

accepting the revenue requirement stipulation in this case, the Commission is not endorsing or approving any principle which may underly the stipulation. The agreement as a whole is found to be reasonable, but no principle which may underly the agreement shall necessarily have precedential value in any future case.

6. All motions, requests for entry of specific Findings of Fact and Conclusions of Law, and any other requests for general or specific relief, if not expressly granted herein, are DENIED for want of merit.

SIGNED AT AUSTIN, TEXAS on this 22d day of September 1988.

PUBLIC UTILITY COMMISSION OF TEXAS

SIGNED: Marta Greytok
MARTA GREYTOK

SIGNED: William B. Cassin
WILLIAM B. CASSIN

I respectfully dissent from the majority's rejection of Section VI of the Examiner's Report and the Findings of Fact and Conclusions of Law supporting that section. I would adopt the probability of dispatch methodology recommended by the examiner.

SIGNED: Jo Campbell
JO CAMPBELL

ATTEST:

Phillip A. Holder
PHILLIP A. HOLDER
SECRETARY OF THE COMMISSION

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MEMORANDUM DECISIONS

TELEPHONE

Lufkin-Conroe Telephone Exchange, Docket No. 7502. Examiner's Report adopted November 12, 1987. Proposed tariff schedules to provide private pay-phone service approved as modified by the staff's recommendations with the agreement of the applicant.

Brazoria Telephone Company, Docket No. 7724. Examiner's Report adopted January 20, 1988. Application approved to authorize the write-off of unrecovered investment in stranded central office equipment and trunk carrier equipment.

Ganado Telephone Company, Docket No. 7918. Examiner's Report adopted November 10, 1988. Special amortization of step switching equipment approved.

San Marcos Telephone Company, Docket Nos. 7919 & 7955. Examiner's Report adopted May 18, 1988. Application approved to change depreciation rates for six classes of equipment.

Southwestern Bell Telephone Company, Docket No. 8037. Complaint of Bruce Penny withdrawn. Order of dismissal signed June 10, 1988.

Southwestern Bell Telephone Company, Docket No. 8075. Proposed tariff schedules to provide optional hunting line service withdrawn by applicant. Order of dismissal signed June 10, 1988.

ELECTRIC

Houston Lighting & Power Company, Docket No. 7375. Application for deferred accounting treatment for Limestone Unit Two. Application withdrawn by applicant. Order of dismissal issued July 21, 1988.

Texas Utilities Electric Company, Docket No. 7619. Examiner's Report adopted on December 21, 1988. The Commissioners approved an amendment to Texas Utilities' certificate of convenience and necessity for a 138 kV transmission line in and about Palestine, Texas.

Rio Grande Electric Cooperative, Docket No. 7767. Examiner's Report adopted April 19, 1988. Application approved to reduce the annual deposit required for irrigation service.

Texas-New Mexico Power Company, Docket No. 7835. Examiner's Report adopted May 20, 1988. Tariff schedules approved to allow the applicant to purchase and resell economy energy on an as-available basis to its Industrial Power Service customers.

Lower Colorado River Authority, Docket No. 7953. Examiner's Report adopted December 12, 1988. Applicant's request for the Ferguson-Buchanan 138 kV transmission line in Burnet and Llano Counties granted.

Lower Colorado River Authority, Docket No. 7954. Examiner's Report adopted December 12, 1988. Applicant's request for the Buchanan-Mormon Mill transmission line in Burnet and Llano Counties granted.

Lower Colorado River Authority, Docket No. 7965. Examiner's Report adopted January 18, 1989. LCRA's standard avoided cost calculation and terms and conditions for the purchase of firm energy and capacity from qualifying facilities, pursuant to P.U.C. SUBST. R. 23.66(h)(3), was approved.

Texas Utilities Electric Company, Docket No. 8015. Examiner's Report adopted July 15, 1988. Application approved to amend certificate to reflect a proposed transfer to the applicant from the Texas Municipal Power Agency of a 6.2 percent interest in Comanche Peak Generating Station and a 20 percent interest in the Comanche Peak-Parker transmission line.