ORIGINAL NEW APPLICATION

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BEFORE THE ARIZONA CORPORATION COMMISSION

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COMMISSIONERS
SUSAN BITTER SMITH, CHAIRMAN
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TOM FORESE

E-01461A-15-0363

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.)	Docket No. W- 01461A-15-______

Arizona Corporation Commission
DOCKETED
OCT 23 2015
DOCKETED BY

TRICO ELECTRIC COOPERATIVE, INC.

APPLICATION
TESTIMONY AND EXHIBITS

VOLUME 1 of 2

OCTOBER 23, 2015

Application

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH, CHAIRMAN
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IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE AND FOR RELATED APPROVALS.	Docket No. W- 01461A-15-______ **APPLICATION**

Trico Electric Cooperative, Inc. ("Trico" or "the Cooperative"), an Arizona nonprofit corporation, through undersigned counsel and pursuant to A.R.S. §§ 40-250 and 40-251 and A.A.C. R14-2-103, hereby submits its Application for an increase to its rates by approximately $2,182,076, or approximately 2.49% over adjusted test year retail rate revenues of $87,430,736 to be effective no later than January 1, 2017.

Trico is also seeking approval of: (i) modifications to its rate design and net metering tariff; (ii) modifications to its Rules, Regulations and Line Extension Policy ("RRLEP"); (iii) updated depreciation rates for its metering facilities; (iv) the inclusion of Direct Assignment Facilities ("DAFs") to be acquired from Southwest Transmission Cooperative ("SWTC") in rate base as post-test year plant and (v) other related matters.

The updates to Trico's rate design and the proposed revenue requirement will result in the current average monthly bill for an average Trico residential member based on 837 kWh consumption to increase from $116.84 to $118.50 (a $1.96 increase).

The Cooperative's request is fully supported by the testimony, exhibits, and schedules submitted with this Application as Attachments 1 through 5.

I. OVERVIEW.

Trico is a member-owned, non-profit, rural electric distribution cooperative headquartered in Marana, Arizona. Trico serves primarily rural areas in Pima, Pinal and Santa Cruz Counties and provides electric service to approximately 38,000 members, most of whom are residential customers. Trico is governed by a member-elected Board of Directors, all of whom are members of Trico. The Board oversees all aspects of Trico's operation and approves the operating budget.

Trico is a Class A Partial Requirements Member ("PRM") of Arizona Electric Power Cooperative, Inc. ("AEPCO"), which generates or procures power on a wholesale basis for Trico and other member distribution cooperatives. Trico is also a Class A Member and network transmission customer of SWTC. Trico obtains almost all of is power from AEPCO and from other wholesale power purchases. Trico's only generation facilities are a 1.750 MW diesel generator located in a remote are for backup purposes, and the 227kW SunWatts Community Sun Farm located at the Cooperative's headquarters.

Trico is currently authorized to charge rates for electric service per Decision No. 71230 (August 6, 2009). The test year used in that proceeding was the 12-month period ending on December 31, 2007. Since its last rate case, Trico has worked diligently to contain its operating expenses and capital costs. As a result, Trico's requested revenue increase is very modest, averaging less than 0.4% per year since the last test year.

Trico's financial health is sound. The need for additional revenue is not driving this Application. Rather, it is being driven by the need to better align the rates of certain classes of Member-customers with the cost of serving them, and to address inequities among Members in the manner in which the fixed cost of providing electric service are recovered by the Cooperative.

Since the last test year, Trico has experienced significant changes in how its Members use energy. While the overall number of Trico Members and the total amount of energy sold by Trico have continued to grow, albeit as a slower rate, increased energy conservation efforts, overall milder weather and expanded distributed generation ("DG") deployment have resulted in decreasing energy usage per residential Member. In particular, the recent escalation in the number of applications to interconnect rooftop solar DG under Trico's Net Metering Tariff has resulted in significant erosion of the Cooperative's ability to recover the fixed costs of providing electric service to its Members, and inequities among its Members in the payment of those fixed costs. All of Trico's Members are connected to Trico's distribution infrastructure and rely on it to provide them with safe and reliable electric service, but all Members are not paying an equitable share of the fixed costs of providing that service.

Trico's Board of Directors believes it has an obligation to provide fair and equitable treatment to all Trico Members, and accordingly has proposed tariff modifications that will continue to promote the growth of DG in Trico's service territory at a steady and sustainable rate, while partially addressing the erosion of fixed cost recovery by the Cooperative and the inequities among Trico Members in the payment of those fixed costs.

This Application also proposes to better align certain other rate classes with the cost of service, incorporate facilities to be acquired from SWTC into the Cooperative's plant and rate base, update the depreciation rate for automated metering equipment, and amend Trico's Rules, Regulations and Line Extension Policy to provide, among other things, a reasonable allowance for line extensions.

II. KEY ELEMENTS OF THE RATE CASE.

A. Net Metering Tariff and Rate Design.

The principal reason Trico is filing this Application is to modify how the costs of providing electric service to its Members are recovered, in order to address increasing inequities regarding who pays for those costs. Trico is proposing to address those inequities in several ways. First, Trico is proposing the same modifications to its Net Metering Tariff that it had previously proposed in Docket No. E.-01461A-15-0057:

1. For energy generated by the DG system that is used contemporaneously to serve the DG Member's load, the DG member will continue to benefit from what is effectively a retail rate offset for such energy.

2. For any excess energy that is delivered to Trico from the DG system, it will provide a credit on the net metered DG Member's bill each month for the excess generation at Trico's avoided cost rate, which is now $0.03662 per kWh.

3. For any energy delivered to the DG Member by Trico, the DG Member will continue to pay Trico for that energy at the tariff retail rate established in this case.

4. Trico is also proposing the same grandfathering date as it previously proposed: All DG Members who had submitted a completed jurisdictional permit application by February 28, 2015 would remain on the current Net Metering Tariff. All other DG Members would migrate to the new Net Metering Tariff upon Commission approval.

Trico is also proposing to raise the monthly customer charges for all customer classes. For residential Members, Trico is proposing to raise the monthly customer charge from $15.00 to $20.00. Increased customer charges will improve revenue stability and lessen the dependence on volumetric energy charges to recover fixed costs, partially mitigating the net metering fixed cost recovery issue.

In addition, Trico is proposing a two-tier inclining block monthly energy rate for its non-time of use residential customers, with a reduced rate for the first 800 kWh. Trico's average residential Member consumes 837 kWh per month. The two-tier energy rate will reduce the impact of the increased customer charge on low-use Members and incentivize energy conservation.

Finally, Trico is proposing adjustments to the revenue recovery from each customer class to better match the actual cost of service for the class. Although the cost of service rates of return for the customer classes are still different, Trico is proposing gradual steps towards better matching revenue recovery to actual cost of service. Under the proposed rates, for example, Trico's General Service Rate Tariff (GS3) class will see an overall reduction in revenue recovery and lower rates. Given the modest overall revenue increase, however, the average residential Member will see only a 1.7% monthly bill increase.

B. **Addition of Acquired Facilities into Plant and Rate Base.**

Under SWTC's policies, the carrying costs associated with transmission facilities constructed and owned by SWTC that are utilized to provide transmission service only to Trico (direct assignment facilities, or "DAFs") are assigned to and paid by Trico. Those costs are passed through directly to Trico's Members. The SWTC DAFs assigned to Trico include all or part of eight transmission substation delivery point facilities with a total approximate net book value as of January 1, 2017, of approximately $7,825,000.

Trico has reached an agreement with SWTC whereby Trico will purchase its DAFs effective as of the date of Commission approval of this Application, for $7,824,026, adjusted as of the date of transfer. The cost of the DAFs to Trico is known and measurable. Therefore, Trico seeks to include the DAFs it is acquiring from SWTC into rate base as post-test year plant, which will reduce the purchased power costs associated with those facilities. Acquiring the DAFs provides Trico with better control over the operation and maintenance expenses of those DAFs, and benefits Trico's Members because Trico will no longer paying a margin to SWTC.

C. **Updated Depreciation for Automated Metering Equipment.**

Trico is seeking to adopt new depreciation rates for its advanced meters. Trico's current meter depreciation rate is based upon mechanical analog meters with an average useful life exceeding 30 years. The Cooperative's metering system is now entirely automated, utilizing both power line carrier and cell based technologies. Because automated meters and related equipment have a shorter useful life than mechanical meters, Trico is proposing that the automated meters and equipment be assigned a 12.9-year depreciation life and a corresponding depreciation rate. Trico's request is based on a depreciation study which considered manufacturing data and industry experience with the advanced meters that Trico has deployed in its service area.

D. **Amendment of Rules, Regulations and Line Extension Policy.**

Trico is proposing modifications to its Rules Regulations and Line Extension Policy ("RRLEP"). Based on Trico's cost of service study for the 2014 test year, Trico is proposing to amend its Line Extension Policy to provide a reasonable allowance toward the cost of new line extensions. For residential line extensions, Trico is proposing an allowance in the amount of $1,500 plus the cost of special equipment (which averages $500). Currently, Trico does not provide any allowance or free footage for line extensions.

Trico is also proposing to amend its RRLEP to update and clarify certain provisions.

E. **Amendment to SunWatts Sun Farm Tariff.**

Trico is proposing a new option for Members to purchase energy from its Community Solar Project – the SunWatts Sun Farm. This option will not require any up-front payment and will allow Members to purchase panel output through a monthly solar energy charge. This solar energy charge will stay fixed for a 20-year term. Under this option, Members can purchase the output in whole-panel increments up to, but not exceeding, their minimum monthly kWh energy usage in the preceding 12 months.

F. **Overall Revenue Requirement.**

In conjunction with the foregoing proposals, Trico seeks to increase its revenue requirement to $89,662,812, or by approximately $2,182,076, which is 2.49% over its adjusted test-year revenue requirement of $87,430,736. Trico utilized a 12-month test year ending on December 31, 2014, for the preparation of this Application and the supporting schedules. The proposed increase includes the addition of the purchased DAFs into Trico's plant and rate base, and reflects a rebasing of the Cooperative's wholesale power and transmission costs. The requested revenue requirement is anticipated to provide sufficient revenues to meet ongoing expenses and capital requirements, maintain a level of equity consistent with a financially healthy enterprise, provide adequate cash flow to meet business requirements and retire capital credits at a reasonable rate, while maintaining adequate Debt Service Coverage and Times Interest Earned

Ratios. This revenue requirement equates to a rate of return of 6.33% on a Fair Value Rate Base of $175,076,536.

III. APPLICATION.

In support of its Application, Trico states the following:

1. Trico is non-profit corporation duly organized, existing and in good standing under the laws of the State of Arizona. Trico's office is located in Marana, Arizona and its mailing address is: 8600 West Tangerine Road, Marana, Arizona 85658, and its telephone number is (520) 744-2944. Trico's CEO/General Manager is Vincent Nitido.

2. The Cooperative is a public service corporation engaged in the transmission and distribution of electricity for sale in Arizona in accordance with the Certificates of Convenience of Necessity issued by the Commission.

3. All communications and correspondence concerning this Application, including data requests and pleadings, should be served on Trico's CEO/General Manager and counsel whose addresses are as follows:

Mr. Vincent Nitido
CEO/General Manager
Trico Electric Cooperative, Inc.
8600 West Tangerine Road
Marana, Arizona 85658.
email: vnitido@trico.coop

and

Michael W. Patten
Jason D. Gellman
Snell & Wilmer, LLP
One Arizona Center
400 East Van Buren Street, Suite 1900
Phoenix, Arizona 85004
Email: mpatten@swlaw.com
jgellman@swlaw.com

4. The Commission has jurisdiction to conduct public hearings to determine the fair value of Trico's property, to fix a just and reasonable rate of return on its fair value rate base, and thereafter, to approve just and reasonable rates designed to give it a reasonable opportunity to earn

such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of hearing, including notice, intervention, filing, service, exhibits, discover, and other prehearing and hearing matters.

5. Accompanying this Application are prefiled testimony and the standard rate schedules described in A.A.C. R14-2-103. The Company's four witnesses are: Vincent Nitido (testimony set forth in Attachment 1); Karen Cathers (Attachment 2); Rebecca Payne (Attachment 3) and David Hedrick (Attachment 4). The supporting schedules are included as Attachment 5.

6. Trico will establish that:

(a) a rate increase is necessary for it to continue to provide safe and reliable service to its customers;

(b) the proposed revenue requirement provides Trico with the cash flow necessary to cover operating expenses, fund needed capital improvements and reserves, gradually increase equity as a percent of assets, maintain capital credit retirements and support adequate DSC and TIER ratios;

(c) its proposed revenue requirement provides for a reasonable rate of return on the fair value rate of the Cooperative's utility property;

(d) its proposed changes to its rate design and Net Metering Tariff are necessary and appropriate to provide more equitable recovery of Trico's fixed costs from its members and are in the public interest;

(e) its proposed revisions to its Rules, Regulations and Line Extension Policy are reasonable and in the public interest; and

(f) its rates are just and reasonable, will provide the Cooperative the necessary revenues to continue to provide adequate, safe and reliable electric service to its customers as required by law, and are in the public interest.

7. Trico is in compliance with all requirements of the Commission.

8. Trico requests that this Commission set a date for a hearing on this Application such that new rates for the Cooperative will become effective no later than January 1, 2017.

9. In addition, Trico requests that the Commission issue a procedural order setting forth the prescribed form of public notice for the Application, and establishing procedures for intervention, and appropriate discovery. Trico further requests that it be allowed to serve all discovery requests, answers and objections electronically.

WHEREFORE Trico respectfully requests that this Commission:

(1) issue a procedural order establishing a date for hearing evidence concerning the Application, prescribing the time and form of public notice to Trico customers, establishing procedures for intervention and discovery as described above;

(2) issue a final order finding and concluding that Trico's rate application is just and reasonable and that granting new rates resulting in an increase in retail revenues of $2,182,076 will allow Trico to cover its operating expenses, fund needed capital improvements and reserves, gradually increase equity as a percent of assets, maintain appropriate capital credit retirements and support adequate DSC and TIER ratios;

(3) issue a final order approving the rates and tariffs proposed in the Trico's Application with an effective date no later than January 1, 2017;

(4) approve the proposed modifications to Trico's Net Metering Tariff and grant a related partial waiver of the A.A.C. R14-2-2301 *et. seq.*;

(4) approve updated depreciation rates for Trico's metering facilities;

(5) approve Trico's revised Rules, Regulations and Line Extension Policy;

(6) grant Trico such additional relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 23rd day of October, 2015.

SNELL & WILMER, L.L.P

By ___________________________
Michael W. Patten
Jason D. Gellman
One Arizona Center
400 East Van Buren Street
Phoenix, Arizona 85004

Attorneys for Trico Electric Cooperative, Inc.

Original and 13 copies of the foregoing filed this 23rd day of October, 2015, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing hand-delivered this 23rd day of October, 2015 to:

Dwight Nodes, Esq.
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Thomas M. Broderick
Director, Utilities Division
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Phoenix, Arizona 85007

By Jaclyn Howard

Attachment 1

(Nitido)

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-_______

Direct Testimony of

Vincent Nitido

on Behalf of

Trico Electric Cooperative, Inc.

October 23, 2015

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Vincent Nitido and my business address is 8600 West Tangerine Road, Marana, Arizona, 85658

Q. What is your position with Trico Electric Cooperative, Inc. ("Trico or "Cooperative")?

A. I am Chief Executive Officer and General Manager of Trico.

Q. Please describe your duties and responsibilities as CEO and General Manager of Trico.

A. I am hired by the Board of Directors to oversee and manage the operation of the Cooperative for the benefit of Trico's Members. I also work with the Board to establish and implement the strategic direction of the organization.

Q. What is the purpose of your direct testimony?

A. I provide an overview of Trico and its service territory and discuss material changes since its last rate case, which was filed in 2008 using a 2007 test year. I also discuss Trico's efforts to contain its costs over the past seven years and the current financial condition of Trico. Finally I explain the reasons that Trico is filing this rate case and provide an overview of Trico's requests in this rate case.

Q. Are other witnesses submitting direct testimony on behalf of Trico in support of its Application?

A. Yes. Karen Cathers, Trico's Chief Operating Officer, as well as David Hedrick and

Rebecca Payne of Guernsey Engineers, Architects and Consultants are also submitting pre-filed direct testimony supporting Trico's general rate case. Ms. Cathers, Mr. Hedrick, and Ms. Payne will address the following issues:

- Ms. Cathers will: (i) provide an overview of Trico's utility operations; (ii) explain the benefits of acquiring certain Direct Assignment Facilities ("DAFs") from our transmission provider, and the related need to include the DAFs in rate base as post-test year plant acquisitions; (iii) describe the impact of proposals in the rate case on Trico's financial condition; (iv) provide an overview of the major proposed rate design changes; (v) support Trico's proposed revisions to its net metering tariff; (vi) describe the proposal to modify Trico's SunWatts Sun Farm Monthly Participation Tariff; and (vii) highlight proposed changes to Trico's Rules, Regulations and Line Extension Policy.

- Mr. Hedrick and Ms. Payne will support the Cooperative's revenue requirement request (including rate base, income and expense adjustments), depreciation, operating margin, rate of return, cost of service studies and additional support for Trico's proposed rate design and revised tariffs, including proposed modifications to the Cooperative's net metering tariff.

Q. Please summarize your testimony.

A. Trico is a Non-Profit Member-owned Electric Distribution Cooperative governed by a Member-elected Board of Directors. Each of the Directors is also a Member of Trico. The Member-Board and the management of Trico operate the Cooperative for the benefit of its membership as a whole.

Trico's current financial health is generally sound. This rate case is not being driven by an immediate need to increase Trico's revenue requirement. Indeed, even though it has been seven years since Trico's last rate case, Trico is seeking only a modest increase in its revenues. Rather, this rate case has several other important objectives.

First, Trico is seeking to modify how its fixed costs are recovered in order to address increasing inequities regarding who pays for the use of Trico's electric grid. Trico believes that its rate proposals in this rate case will lead to more equitable and sustainable rates for its Members. These proposals seek to modify Trico's rate design to: (i) recover fixed grid costs associated with existing distributed generation within Trico's service territory by increasing the fixed monthly customer charge and decreasing the volumetric energy rate for all Members; (ii) better match fixed cost recovery by customer class to the cost of service for that class; and (iii) reduce the fixed cost-shift and resultant subsidies to Members who install rooftop solar or other distributed generation after March 1, 2015.

Second, Trico is acquiring certain DAFs from Southwest Transmission Cooperative ("SWTC") and seeks to add that plant to its rate base, thereby acquiring ownership and control of the costs for facilities that are used and paid for by Trico. The 2.49% revenue requirement increase requested by Trico includes the carrying costs of the DAFs, and those carrying costs will be removed from Trico's Wholesale Power Cost Adjuster. Ms. Cathers' provides additional detail regarding Trico's acquisition of the DAFs in her testimony.

Third, Trico seeks to update its Rules and Regulations and Line Extension Policy ("RRLEP"). Trico does not currently provide any line extension allowance but believes that a modest allowance is now appropriate given Trico's anticipated growth rate.

Fourth, Trico seeks to update its depreciation rates for advanced metering equipment, to more accurately reflect the useful life of those assets.

Finally, Trico is proposing modifications to its interruptible rates, and is seeking approval of a new SunWatts Sun Farm Monthly Participation tariff.

Q. Will Trico's proposals resolve all the inequities surrounding Trico's recovery of the fixed costs of its distribution infrastructure?

A. No, they will not. However, Trico believes the proposals are a significant step toward mitigating the inequities that are developing in its current rate and tariff structure. Trico believes a gradual approach to modifying its rate design is in the best interest of its Members. For example, in the case of Trico's proposed modification of its Net Metering tariff, Trico believes that while the proposal does not fully mitigate the transfer of fixed costs associated with distributed generation, it strikes an equitable balance between the continued development of a robust rooftop solar program against the cost to Members without solar. Over time, as the cost of solar continues to decline and the efficiencies continue to improve, the transfer of fixed costs can be further addressed until the point where distributed solar generation is an economic resource choice without such subsidies.

II. OVERVIEW OF TRICO.

Q. Please describe Trico's service territory and customer profile.

A. Trico is a member-owned, non-profit, rural electric distribution cooperative headquartered in Marana, Arizona. Trico serves rural areas in both Pinal and Pima Counties and provides electric service to approximately 43,000 active services, of which over 40,000 are residential customers. Trico has added about 5,000 active services since its last rate case. Prior to the economic slowdown in 2008, Trico was one of the fastest growing electric distribution cooperatives in the country, experiencing average growth of over 6% annually in both customers and energy requirements with growth in excess of 10% in customers and energy in the 2006 to 2007. Growth has slowed since 2007, Trico's last rate case test year. Since that time, growth in the number of new customers has continued at an annual 2% to 3% rate, while energy requirements have grown at 1% to 2% annually.

Q. How many employees does Trico have?

A. Trico employs approximately 125 full-time employees, more than half of whom are linemen and field crews. Trico has a 15 person call center and 20 employees in design and engineering related work. The remaining employees support information technology, accounting, human resources and administrative services.

Q. Please describe the plant that Trico owns.

A. Trico owns no generation facilities other than a 1.750 MW diesel generator located in a remote area which is exclusively used for backup and a 0.227 MW solar facility used for its Community Solar program.

Trico has over 3,711 miles of underground and overhead distribution system. Trico also owns over 31 miles of transmission lines, as well as three substations (at or above 69 kV).

Trico is in the process of acquiring DAFs from SWTC. DAFs are defined in the service agreements between Trico and SWTC as those transmission facilities constructed and owned by SWTC, after September 1999, that are not part of the SWTC system facilities and utilized to provide transmission service only to Trico, consistent with the Federal

Energy Regulatory Commission applicable decisions. The carrying costs associated with the SWTC DAFs are passed through directly to the Member that is assigned those DAFs. These carrying costs include but are not limited to interest, depreciation, taxes, operations, maintenance, and margins. The current SWTC DAFs assigned to Trico include all or part of eight transmission substation delivery point facilities with a total approximate net book value as of January 1, 2017, of $7,825,000.

Q. Please provide an overview of Trico's commitment to safe and reliable service.

A. Trico system reliability consistently scores very high with an Average Service Availability over 99.98%. Trico's SAIDI (system average interruption duration index) and SAIFI (system average interruption frequency index) are in the 1st quartile nationally based on the National Rural Electric Cooperative Association Scorecard. Trico continues to have a strong culture of safety and reliability.

Q. How is Trico governed?

A. The Cooperative is governed by a seven-Member Board of Directors, elected by Trico Members. One Director is elected from each of seven Director Districts.

Q. How is an electric distribution cooperative different from an investor owned utility?

A. Electric cooperatives were originally conceived of and financed through New Deal legislation adopted to promote rural electrification. That is, to bring electricity to those areas of the Country that were not economically viable for investor owned utilities to serve. The mission of electric cooperatives today continues to be to provide reliable power at an affordable cost to areas that cannot be served economically by investor owned entities. That historical background serves as the basis for two significant differences between electric distribution cooperatives and investor owned utilities. First, because there are no external investors or shareholders, distribution cooperatives are owned and governed exclusively by their Members – the customers they serve. Members elect a Board of Directors from the membership, and the Board is charged with running the cooperative for the benefit of the Members, in the best interest of the Members. Margins produced through the business operations of a distribution cooperative are allocated to the capital accounts of the Member-owners. There are no third-party investors or stockholders who receive a return outside of the cooperative's customers.

Second, and perhaps more significant from a ratemaking standpoint, the fact that electric distribution cooperatives serve areas that are not economically viable for investor owned utilities underscores that the cost of service for rural electric cooperatives is invariably higher than that of investor owned utilities. By way of illustration, Trico serves approximately 10 Members per mile of distribution line, which is a small fraction of the customers per mile of line served by the State's investor owned utilities (e.g. Arizona Public Service has about 100 customers per mile of distribution line and Tucson Electric Power has about 60 customers per mile of distribution line). Fewer people per mile of line means that Trico's fixed cost per Member are significantly higher than for customers of more highly concentrated more urban utilities. Higher fixed costs typically equate to higher rates, and Trico's rates continue to be higher than those of Arizona investor owned utilities. Higher fixed costs per Member also result in comparatively more lost fixed costs when Members generate power under a Net Metering tariff, and a higher amount of subsidy to distributed solar generation Members who are credited for excess power at the retail rate. For that reason, Trico believes a "one-size-fits-all" policy relating to compensation or credit for power produced through distributed generation is not appropriate.

III. CHANGES SINCE TRICO'S LAST RATE CASE.

Q. When was Trico's last rate case?

A. Trico's last rate case was filed on August 15, 2008, using a test year that ended on December 31, 2007. The Commission approved Trico's current rates on August 6, 2009 in Decision No. 71230 (Docket No. E-01461A-08-0430).

Q. How has Trico changed since its last rate case?

A. The most significant changes result from the impact of the aforementioned economic downturn that started just as our last rate case was completed, the way in we purchase power for our Members, and the impact of distributed renewable generation on Trico's cost structure.

Following the economic downturn, Trico's growth continued at a much slower rate. As a result, we scaled back the amount of capital expenditures from what we had anticipated prior to 2008. Lower capital expenditures combined with the elimination of allowances for line extensions have contributed to steady improvement in our equity since the last rate case.

Trico has also converted from an All Requirements Member ("ARM") to partial requirements status with our principal power supplier, Arizona Electric Power Cooperative, Inc. ("AEPCO") since our last test year. As a Partial Requirements Member ("PRM") of AEPCO, Trico receives a more favorable rate for power supplied by AEPCO, and we are able to purchase our power requirements over and above our allocated capacity in AEPCO generating resources from any source, including AEPCO. That has allowed us to access additional power supply alternatives for our Members. Trico entered into a 10-

year Power Purchase Agreement with Tucson Electric Power Company ("TEP") effective January 1, 2015, under which Trico will purchase 50MW of capacity and energy each year through 2017, and 85MW each year thereafter until 2025.

Finally, since our last rate case, Trico has experienced a significant increase in distributed generation deployment in our service area. While this is partially a result of the Commission's Renewable Energy Standard and Tariff rules ("REST Rules"), the biggest impact to Trico has been the dramatic increase in leased rooftop solar installations within our service territory that began in the latter part of the test year, 2014. As detailed in Ms. Cathers' and Mr. Hedrick's testimony, this rapid increase lead to an accelerated accumulation of unrecovered fixed costs, which Trico seeks to partially address in this rate case.

Q. Has Trico experienced any significant changes in the amount of energy (kWh) usage per customer?

A. Yes, while the number of customers and the total energy supplied by Trico have both increased since our last rate case (albeit at a slower rate), the average monthly residential energy usage per customer has decreased steadily from about 900 in 2008 to about 800 in 2014. This is likely a result of energy conservation efforts by Trico Members, generally milder weather trends and increased renewable resources within Trico's service territory.

Q. Since the last rate case, has Trico commenced filing renewable energy implementation plans separate from AEPCO?

A. Yes. In 2010, Trico filed its first stand-alone implementation plan – approved in Decision 72086 (January 20, 2011), and has filed separate implementation plans each year since then. Trico has had a renewable energy program in place since 2005. After the

REST Rules were adopted, Trico associated with AEPCO's renewable energy plans through 2010 (albeit with a separate tariff).

Q. Has Trico maintained a successful renewable energy plan over the years?

A. Trico has established and maintained a vibrant renewable energy program – principally focused on distributed solar generation. This includes the SunWatts Residential and Commercial Rebate Program that still offers to assist customers with the interconnection of distributed solar systems (and which had offered incentives from 2011 through 2013). Trico also has been a leader in Community Solar and installed a 227 kW facility to provide a Community Solar option for its Members – the SunWatts Sun Farm project. I am proud of the fact that Trico was recognized by the Solar Electric Power Association ("SEPA") as the Solar Cooperative of the Year in the United States for 2012. We believe Trico has had and continues to have a robust portfolio of renewable energy programs.

Q. Would Trico be in compliance with the REST Rules target for distributed generation if it were an investor-owned utility?

A. Yes. While Trico, as an electric cooperative and as set forth in A.A.C. R14-2-1814, is not subject to mandatory targets, I am happy to say that it currently exceeds the Commission's renewable energy standard distributed generation target for investor-owned utilities.

Q. Please describe in more detail what Trico has experienced since its last rate case with respect to its Members installing rooftop solar Photovoltaic ("PV") systems ("DG systems")?

A. Under its REST plans, which were adopted after the last rate case, Trico began to see Members installing DG systems at a steadily increasing rate. Initially, Trico was paying significant upfront incentives to Members with DG systems - up to 30 percent of the cost of the system. As PV costs declined and efficiency improved, Trico, like other Arizona utilities reduced its upfront incentives. Yet as anticipated, deployment of DG systems in Trico's service area continued to grow steadily through the middle of 2014. Annual DG applications grew from 65 in 2011, to 160 in 2013.

However, in late 2014 and early 2015, the number of applications for DG system interconnection skyrocketed, largely as a result of the development of the financial leasing model for DG systems. In December 2014 alone Trico received 114 applications. It received 74 applications in January 2015 and 174 applications in February 2015. As a result, Trico experienced a rapid increase in unrecovered fixed costs. As Trico is a Member owned distribution cooperative, the proliferation of DG systems has the effect of shifting the ultimate recovery of those lost fixed costs to those Members who have not installed DG systems. Trico seeks to partially address the acceleration of that cost shift in this rate case.

Q. Is Trico committed to its renewable energy programs going forward?

A. Definitely. Trico's proposed 2016 REST plan continues its commitment to DG, community solar, and working with local agencies to provide subsidized solar installations and grants for renewable energy education. Ms. Cathers will detail Trico's proposed changes to its Sun Farm Monthly Tariff that is part of this Application. Trico's proposed 2016 REST plan also provides for a study of the potential acquisition of large or utility-scale solar by the Cooperative. Utility scale solar owned directly by the Cooperative is more cost-effective than DG and does not result in lost fixed costs or cost shifts among Members.

Trico wholeheartedly supports sustainable deployment of renewable resources in its service area, including DG systems. As Directors of a Member owned cooperative, however, Trico's Board must balance the objective of maintaining a robust renewable energy program against the cost impact to all of Trico's Members. Trico does not believe that the current fixed cost shift associated with the acceleration of DG systems is necessary to maintain a reasonable and sustainable growth in renewable resources in Trico's service territory, and is seeking to partially address that shift in this rate case.

IV. COST CONTAINMENT EFFORTS SINCE THE LAST RATE CASE.

Q. Please describe Trico's efforts to contain costs over the past few years.

A. Perhaps the most significant cost containment since our last rate case resulted from Trico's conversion from ARM to PRM status with AEPCO in 2011. As an ARM, Trico was assessed a kWh rate for fixed costs associated with its allocated capacity in AEPCO generating units. This had the effect of escalating Trico's fixed generation costs as its load grew, even though its allocated capacity in AEPCO's generating units remained the same. As a PRM, Trico, like the other AEPCO PRMs, is assessed a flat fixed cost charge rather than a kWh rate, so that Trico's fixed charge no longer increases with Trico's load. Overall, the conversion to PRM status has resulted in power cost savings of more than $5 million annually for Trico Members.

Another major cost saving effort involved refinancing most of Trico's debt with the USDA Rural Utility Service ("RUS"). Since its last rate case, Trico has refinanced over $50 million of 5% RUS debt at significantly lower rates, while maintaining the same maturity schedule. That has resulted in annual savings in excess of $1 million.

I believe Trico has done a very good job of controlling our day-to-day operating costs while maintaining a safe, reliable distribution system. Employee headcount has remained flat over the last 7 years, and employee expenses have remained under control. Health insurance premiums have declined over the last three years, due in part to the Cooperative's wellness program. Our efforts to control costs are evidenced by the fact that our revenue requirement has increased by less than 2.5% overall in the 7 years since our last test year.

Q. Will these efforts continue into the future?

A. Yes. The Trico Board and employees are always mindful of our obligation to provide safe, reliable service to our Members at the lowest cost possible. Those cost control efforts will be even more critical in the future as we face potentially large increases in the cost of power following the implementation of environmental compliance measures resulting from the Environmental Protection Agency's recently promulgated Clean Power Plan, Regional Haze Rules and Mercury Standards, along with new Ozone Standards set to be released in the near future.

V. CURRENT FINANCIAL CONDITION.

Q. Please describe the current financial condition of Trico.

A. Trico is in good financial condition. Since its last rate case was concluded in 2009, Trico's Equity to Asset Ratio increased from under 28 percent to almost 40 percent for the 2014 test year, and had Operating Margins of $4.6 million in 2014. Cash and Cash Equivalents at year end were $8.5 million. The Cooperative has retired $1.5 million in capital credits to Members in each of the last 3 years.

Trico's Debt Service Coverage ("DSC") is 1.70 and its Operating Times Interest Earned Ratio ("TIER") is 1.57. These are healthy ratios.

VI. REASONS FOR FILING RATE CASE.

Q. What are the main reasons that Trico is filing this rate case?

A. First, Trico is seeking to modify how its fixed costs are recovered in order to address increasing inequities regarding who pays for the use of Trico's electric grid. Trico believes that its rate proposals in this rate case will lead to more equitable and sustainable rates for its Members. These proposals seek to modify Trico's rate design to: (i) recover fixed grid costs associated with existing distributed generation within Trico's service territory by increasing the fixed monthly customer charge and decreasing the volumetric energy rate for all Members; (ii) better match fixed cost recovery by customer class to the cost of service for that class; and (iii) reduce the fixed cost-shift and resultant subsidies to Members who install rooftop solar or other distributed generation after March 1, 2015.

Second, Trico is acquiring certain DAFs from SWTC and seeks to add that plant to its rate base, thereby acquiring ownership and control of the costs for facilities that are used and paid for by Trico. The 2.49% revenue requirement increase requested by Trico includes the carrying costs of the DAFs, and those carrying costs will be removed from Trico's Wholesale Power Cost Adjuster. Ms. Cathers' provides additional detail regarding Trico's acquisition of the DAFs in her testimony.

Third, Trico seeks to update its RRLEP. Trico does not currently provide any line extension allowance but believes that a modest allowance is now appropriate given

Trico's anticipated growth rate. Trico will also be updating and clarifying certain provisions of the RRLEP.

Fourth, Trico seeks to update its depreciation rates for advanced metering equipment, to more accurately reflect the useful life of those assets.

Finally, Trico is proposing various modifications to its interruptible rates, and is seeking approval of a new SunWatts Sun Farm Monthly Participation tariff.

Q. Why are the rate design changes needed at this time?

A. We believe that this rate case is a proactive effort to move towards equitable and sustainable rates for our Members. If we have a rate design that better matches our rates to the cost of service, our Members will pay a fair and equitable amount for their use of the Trico grid, and Trico will better position itself for long term financial stability. This rate case will not fix all of the rate design issues, but it is a step toward that fix.

Q. Is the growing amount of unrecovered fixed costs from DG Members a key reason for filing this rate case?

A. Yes. While our rate design proposals address more than just the growing amount of unrecovered fixed costs from DG Members, the rate design changes – such as increasing the monthly customer charge and reducing the amount of credit for energy produced above the DG Members' need -- do seek to address that problem. Those proposed revisions will significantly but not fully alleviate the cost recovery problems caused by the growing number of DG Members.

Q. Why isn't Trico proposing a demand rate for DG Members?

A. Although a demand rate for DG Members is an additional way to ensure that DG Members pay an equitable share of Trico's fixed costs, Trico believes that its proposals for a higher monthly charge and a modified net metering tariff are appropriate first steps in addressing the DG cost shift and having DG Members pay a more equitable share of the fixed costs of Trico's distribution infrastructure. Trico is concerned that a demand rate for DG Members would add a higher degree of complexity to Member bills than the modifications it has proposed. In addition, Trico has proposed to "grandfather" Members who applied for a DG interconnection prior to March 1, 2015 under the existing net metering tariff, because those Members acquired and sized their DG systems based on the tariffs at that time without knowledge of the proposed changes. Trico's Board believes it should not dramatically change cost structure for these original DG systems as a matter of fairness. Applying a demand charge to those grandfathered Members would be inconsistent with the Board's determination in that regard. Alternatively, creating a demand charge only for new net metering customers would be difficult to administer and explain, and would likely create issues in the future regarding applicability of the rate.

Q. Are the costs to serve DG Members mitigated or lowered by the fact that they have DG systems?

A. No. DG Members remain connected to the grid. Their peak demand does not necessarily change because of their DG system and their DG system does not always provide sufficient energy to meet their load. A DG Member essentially becomes a partial requirements customer. Still, Trico is responsible for delivering the same quality of service as before. So when there is cloud cover or when it is night, the Cooperative still must provide the same level of service as if the DG Member did not have a solar DG system. Trico must make sure the "lights are kept on" for that DG Member. Further, the

DG Member benefits from being interconnected to Trico's distribution grid, so that the DG Member has a place to shed excess energy generated by the DG system.

As a result, DG Members still need the same distribution and customer services, and incur the same costs as before. And Trico has already incurred these costs for providing service to DG Members. In fact, the costs to serve DG Members may be higher due to the greater usage of the network (typical customers do not push power into the grid). Trico has increased costs related ensuring the grid continues to operate at proper voltages, particularly when significant DG energy is being pushed back into the network.

Q. How does net metering factor into this problem?

A. Net metering in Arizona allows a customer to offset its energy costs at the retail rate for every kWh that the customer generates from a DG system. So when a DG Member uses energy produced by the DG system, the DG Member is not charged the energy rate by Trico for that energy (therefore not paying for the fixed distribution and customer costs designed to be recovered through the per-kWh energy rate.)

The problem is exacerbated by the fact that the excess energy the DG system produces, which goes back onto Trico's distribution grid, is credited to the customer at the full retail rate. The DG Member essentially gets a "rolling back" of the meter for that excess energy at the full retail rate – even when it is Trico that incurs the costs embedded in that rate (based on the fixed costs to serve that DG Member.) When excess energy is credited at the retail rate, this amplifies the lost fixed-cost problem for Trico. The amount of unrecovered fixed cost is growing significantly and rapidly, as Ms. Cathers explains in her direct testimony.

Q. Has the Commission already recognized this problem?

A. Yes. We noted in our Application in Docket No. E-01461A-15-0057 that the Commission recognized the existence of the cost-shift burden for Arizona Public Service Company in Decision No. 74202 (December 3, 2013). Specifically, the Commission found that the growth of DG systems in APS's service territory "results in a cost shift from APS's DG Customers to APS's non DG residential customers absent significant changes to APS's rate design."

Q. Is this a problem even assuming that DG provides future benefits in the near-and-long term?

A. Yes. The fixed costs I discussed earlier are embedded costs. Trico has already incurred those costs. The retail rates approved in Decision No. 71230 factor in these fixed costs, as do our proposed rates in this docket. Even with the proposal to recover more of a percentage of fixed costs through the monthly customer charges, a substantial percentage of recovery of fixed costs will remain dependent on the volumetric or commodity rate (the per-kWh energy rate.) Trico's rates are based on the cost of providing service, and not the comparable benefits of one resource over another in a future time period.

As it currently stands, crediting excess energy at the retail rate exacerbates the cost-shift to non-DG Members. Crediting at the avoided-cost rate still gives DG Members a credit for excess energy, but at a lower rate, which lessens the cost-shift problem going forward. But because DG Members still offset their own use at the full retail rate, and thereby avoid paying for the fixed costs embedded in the retail energy rate, the cost-shift problem is not eliminated. Trico's proposed rate design changes coupled with the proposed net-metering tariff revisions will significantly mitigate the problem, although it will not eliminate it. DG Members will still receive a subsidy equivalent to the avoided fixed costs on the energy produced by their system for their own use.

Q. Does Trico have the benefit of a lost-fixed cost recovery mechanism to at least partially address this problem?

A. No, and Trico is not proposing such a mechanism in this case. From the perspective of the Trico Board, a lost fixed cost recovery mechanism merely shifts the fixed costs from DG Members to non-DG Members. The Board does not believe it necessary or appropriate to institutionalize that cost shift, but rather seeks to balance the objective of maintaining a sustainable growth in DG within Trico's service territory against the cost of doing so to non-DG Members. Trico is proposing to mitigate the unrecovered fixed costs and cost-shift dilemmas through a simpler and more equitable approach which will continue the development of solar at a reasonable rate, understanding that something further may need to be done in a future rate case.

Q. Does the fact that Trico is a member-owned cooperative have particular impacts different from an investor-owned utility?

A. Yes. As I indicated earlier, electric distribution cooperatives like Trico typically have a higher cost of service than investor-owned utilities, for the most part associated with the grid costs (fixed generation, transmission and distribution). As a result, the lost fixed costs associated with Member-owned DG are comparatively much higher for a rural cooperative. In particular, by crediting a DG Member at the retail energy rate for excess power produced by the DG system, Trico is paying more for the power than investor owned utilities would pay on their systems. In addition, because Trico is Member-owned, lost fixed costs that are not otherwise recovered through Trico's Wholesale Power Cost Adjuster (i.e. fixed costs of the distribution system) act to reduce the capital accounts of non-DG Members until such costs are included in the revenue requirement through a rate case, which results in an immediate shift of cost from the DG Members to the remaining Members.

Q. Had Trico attempted to address the problem of unrecovered fixed costs due to net metering before this filing?

A. Yes, Trico had proposed the same revisions to its net metering tariff in a separate Application filed earlier this year in Docket No. E-01461A-15-0057. Ultimately, Trico determined that it would withdraw all but its request to amend the avoided cost rate to \$0.03662 per kWh. The Commission approved the partial withdrawal and the amended avoided cost rate.

Q. Had Trico engaged in significant outreach notifying persons of the potential changes to its net metering tariff in February?

A. Yes. In connection with its February 2015 Application, Trico directly contacted solar contractors active within its service area and in the City of Tucson metropolitan area. We posted notification and information on Trico's website and sent a direct mailing to our Members. At that time, we modified Trico's interconnection application documentation to require potential net-metering Members to acknowledge in writing that they are aware of Trico's Application to seek approval for the new net-metering tariff. We have since made changes to those items to be consistent with the Commission's decision approving Trico's partial withdrawal of its February 2015 Application.

Q. Besides improving the equitable recovery of fixed costs, do you believe Trico's Members benefit from the filing of this rate case?

A. Yes, I do. As I noted above, this rate case will help maintain the financial health and stability of Trico and meet the Board's financial objectives, such as increasing equity as a percentage of Trico's assets, maintaining a healthy level of cash, maintaining capital credit retirements at a strong and sustainable level, and maintaining strong DSC and TIER ratios.

VII. OVERVIEW OF RATE CASE.

A. Revenue Requirement.

Q. Please describe the Cooperative's revenue request in its Application.

A. Trico is seeking approval of a revenue requirement of $89,662,812, which is an increase of $2,182,076, or 2.49%, over adjusted test year revenues, to be effective no later than January 1, 2017. The revenue increase includes the carrying costs of the DAFs that Trico is purchasing from SWTC, and there will be a corresponding decrease in power costs passed through Trico's Wholesale Power Cost Adjuster as a result. The requested revenue requirement will provide Trico sufficient cash flow to cover its operations, to fund future necessary plant additions, replacements and improvements and to service its debt.

B. Rate Design.

Q. What rate design changes is Trico proposing?

A. Trico is proposing to raise the monthly customer charges in a gradual manner, but in a way that results in the Cooperative being less dependent on volumetric energy charges to cover fixed costs. Trico is proposing to raise the monthly customer charges by approximately $5.00 for most residential and general service customers.

For standard service residential Members, Trico is proposing to increase the monthly charge from $15 to $20. Trico is also proposing a two-tier inverted block rate design for residential Members, which will lessen the impact of the increased monthly charge on lower-use Members, including DG Members. Trico is further proposing to adjust the energy (per kWh) rate for most customer classes in order to bring them closer to the actual cost of service. Currently, certain classes are covering more of Trico's fixed costs than the cost of service study supports. For example, under the proposal, some of Trico's commercial customers will see a decrease in their energy rate.

Both Ms. Cathers and Mr. Hedrick detail the rate design changes in their respective direct testimonies.

Q. What will be the impact of the rate case on residential bills?

A. The average residential Member uses 837 kWh per month. Under our proposals, that customer will see the average monthly bill go from $116.84 to $118.80, an increase of $1.96 per month (or 1.68%).

C. Net Metering Tariff.

Q. How is Trico proposing to revise its Net Metering Tariff?

A. Trico's proposal remains the same as it proposed in its Application in February 2015. Trico's proposed change *only* affects the credit for excess generation from the DG Member's facility. Trico will still provide a credit on a net-metered DG Member's bill each month for the excess generation; but this will be credited at the avoided cost rate that has been approved by the Commission (currently $0.03662 per kWh). DG Members will no longer be able to "bank" the excess generation from their DG systems to offset the cost of future usage.

Q. Will Trico's proposal have any effect on energy generated from the DG system that is used to serve the DG Member?

A. No. The DG Member will continue to benefit from what we described as a retail-rate offset for that energy the DG Member uses that is generated from the DG system.

Q. Why is Trico proposing to credit excess energy from DG Members at the avoided cost rate?

A. The avoided cost rate is a more accurate calculation of the value to Trico of the excess energy produced by the DG Member's system. Trico does not believe it is a responsible use of the Members' money to pay more for energy from DG systems that it could otherwise purchase the power on the wholesale market. Trico's Board believes the retail-rate offset for energy that the DG Member actually uses provides an adequate subsidy and incentive to promote the continued sustainable growth of residential DG in our service territory, based on the volume of applications we have continued to receive since the proposed changes were communicated to our Members.

Q. Has Trico proposed the new Net Metering Tariff apply to all DG Members?

A. No. Trico is proposing to have its new Net Metering Tariff apply only to those members who had submitted interconnection applications to Trico after February 28, 2015. All other DG Members would be grandfathered under the current Net Metering Tariff. Moreover, the new Net Metering Tariff would apply from its effective date forward.

Trico has notified DG Members of this through mailed notices, the interconnection application for DG and on Trico's website describing its renewable energy programs.

D. Rules, Regulations and Line Extension Policy.

Q. Is Trico also proposing changes to its Rules and Regulations, including its Line Extension Policy?

A. Yes. Ms. Cathers and Mr. Hedrick provide further detail in their testimony, but the biggest change Trico is proposing is to provide an allowance for new line extensions. Presently, Trico does not provide an allowance or free footage for line extensions. Trico's proposed Line Extension Policy for residential Members will provide an allowance of up to $1,500 plus the cost of special equipment (transformer and meter that averages approximately $500 per residence). Trico anticipates that the associated increase in its capital plan would be approximately $1.5 million per year.

Q. Why is Trico proposing a line extension allowance?

A. Up until its last rate case, Trico paid the entire cost of line extensions. That policy, combined with the significant backbone and infrastructure costs associated with the explosive growth Trico experienced prior to 2008, resulted in very high levels of capital expenditures and significant strain on Trico's financial resources. The Cooperative came uncomfortably close to violating financial covenants under its loan agreements, and its equity dropped precipitously. As a result, in its 2008 rate case, Trico proposed the elimination of any allowance for line extensions. That action, along with the economic slowdown that followed, has contributed to Trico's increased financial strength since that time.

Growth in Trico's service area has continued since 2008, but at a much slower rate. Trico believes it is now appropriate to reinstate a modest line extension allowance. Trico's cost of service study indicates that the revenue stream associated with new service interconnections will support an allowance in the amount proposed. In addition, TEP offers a free footage allowance for new interconnections. Because of Trico's proximity to TEP's service territory Trico believes the lack of a line extension allowance creates a disincentive to locate new development in Trico's service territory.

E. Updated Depreciation Rates.

Q. What is Trico proposing for depreciation rates in this docket?

A. Trico is seeking to adopt new depreciation rates for its advanced meters. The current meter depreciation rate is based upon mechanical analog meters with an average useful life exceeding 30 years. Trico's metering system is now entirely automated, utilizing both power line carrier and cell based technologies. Automated meters have a much shorter useful life than mechanical meters. Therefore, Trico is proposing that the automated meters and equipment have a 12.9-year depreciation life with a corresponding depreciation rate, based on industry experience with the advanced meters that Trico has deployed in its service area. Ms. Payne addresses this in more detail in her testimony.

VIII. BOARD AUTHORIZATION AND SUPPORT FOR THE RATE CASE.

Q. Did Trico's Board approve this rate case filing?

A. Yes, the Board approved this filing on September 22, 2015.

Q. Do you and Trico's Board believe that approval of its Application is in the public interest?

A. Yes. The proposals in Trico's Application represent what the Member-elected Trico Board has determined is an appropriate balance between maintaining the financial health of the Cooperative against the cost to its Members. Trico's proposed changes to its net metering tariffs will continue the sustainable growth of distributed generation in the service territory while appropriately moderating (but not eliminating) the subsidy and cost-shift among Members.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment 2

(Cathers)

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-____

Direct Testimony of

Karen Cathers

on Behalf of

Trico Electric Cooperative, Inc.

October 23, 2015

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<u>Exhibits</u>

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Karen Cathers and my business address is 8600 West Tangerine Road, Marana, Arizona, 85658

Q. What is your position with Trico Electric Cooperative, Inc. ("Trico" or the "Company")?

A. I am the Chief Operating Officer of Trico.

Q. Please describe your responsibilities as Trico's Chief Operating Officer.

A. Among my responsibilities as Chief Operating Officer of Trico are the management and oversight of the: (i) power supply forecasting, planning and acquisition; (ii) transmission and distribution planning, engineering, and design; (iii) regulatory affairs; and (iv) renewable and energy efficiency programs. The formulation and implementation of Trico's net metering program and tariff are included within those responsibilities.

Q. Please summarize your direct testimony.

A. In my testimony, I will:

1. Provide an overview of Trico's wholesale power purchases;
2. Provide a description of Direct Assignment Facilities ("DAFs") that Trico is acquiring from Southwest Transmission Cooperative, Inc. ("SWTC") and address why Trico is acquiring those facilities;
3. Provide an overview of the anticipated financial impact of the rate case proposals on Trico's financial condition;
4. Address Trico's proposed rate design, including an overview of our proposed tariffs;
5. Describe our proposed revisions to Trico's Net Metering Tariff and the reasons for those revisions;

6. Describe our proposed Sun Farm Community Solar Monthly Tariff;

7. Address the proposed revisions to the Rules, Regulations and Line Extension Policy ("RRLEP").

I am the witness that is sponsoring our proposed tariffs and our proposed RRLEP.

II. OVERVIEW OF TRICO OPERATIONS.

Q. Please describe the plant that Trico owns.

A. Trico owns no generation facilities other than a 1.750 MW diesel generator located in a remote area which is exclusively used for backup and a 0.227 MW solar facility used for its Community Solar program.

Trico has over 3,711 miles of underground and overhead distribution system. Trico also owns over 31 miles of transmission lines, as well as three substations (at or above 69 kV).

Trico is in the process of acquiring DAFs from SWTC. DAFs are defined in the service agreements between Trico and SWTC as those transmission facilities constructed and owned by SWTC, after September 1999, that are not part of the SWTC system facilities and utilized to provide transmission service only to Trico, consistent with the Federal Energy Regulatory Commission applicable decisions. The carrying costs associated with the SWTC DAFs are passed through directly to the Member that is assigned those DAFs. These carrying costs include but are not limited to interest, depreciation, taxes, operations, maintenance, and margins. The current SWTC DAFs assigned to Trico include all or part of eight transmission substation delivery point facilities with a total approximate net book value as of January 1, 2017, of approximately $7,825,000.

Q. How does Trico acquire the power that it delivers to its Members?

A. Trico is a Class A partial requirements member of Arizona Electric Power Cooperative, Inc. (AEPCO), which generates or purchases power on a wholesale basis for Trico and other partial and all-requirement member distribution cooperatives. For the test year, Trico purchased approximately 75% of its energy from AEPCO owned units and 25% from other wholesale sources, although historically all of Trico's capacity requirements have been purchased from AEPCO. AEPCO charges Trico at wholesale for the generation capacity through a fixed monthly dollar charge currently $1,349,893 per month or $16 million per year as adjusted by AEPCO from time to time though ACC approval. AEPCO charges Trico for energy based on variable fuel costs at a fixed based rate that is adjusted either up or down pursuant to the AEPCO Purchased Power and Fuel Adjustor Clause ("PPFAC") as approved by the ACC. Trico is also a member of SWTC. Trico purchases transmission service from SWTC to deliver its rights in the AEPCO generating units and power from other sources to Trico loads. SWTC charges Trico a demand load ratio share of the SWTC fixed revenue requirement as approved by the ACC in its last rate case for network transmission and also charges Trico for point-to-point transmission under a several service agreements. Trico has also entered into a 10 year power supply agreement with Tucson Electric Power Company, effective as of January 1, 2015, for a capacity of 50 megawatts from 2015 through 2017 and 85 megawatts from 2017 through 2024. This new purchase power agreement replaces approximately 80 megawatts from two AEPCO-owned summer purchase power agreements, which terminated as of October 31, 2014. The new purchase power agreement and the termination of the two AEPCO-owned summer purchase power agreements are both included in the Trico rate case as test year adjustments to the Trico wholesale power and transmission costs.

Q. How are Trico's power costs reflected in Trico's rates?

A. Trico's power and transmission costs are approximately 65% of its total costs. Its base unbundled rate includes three elements: (i) a wholesale power energy cost, (ii) a wholesale power and transmission fixed cost and (iii) a distribution system fixed cost. Each of these three components are about one third of Trico's costs, where about two thirds of Trico costs are related to fixed (generation, transmission and distribution) and one third is related to variable fuel or energy costs. For residential customers, Trico does not have a demand charge. Although some of the fixed Trico costs are recovered in the customer charge, Trico would need to have approximately an $85 per month customer charge to recover all of the fixed costs associated with the average residential customer. The current rates for residential customers are composed of the following:

Trico Current Residential Rate Components			
	Current Rates	Avg Res Bill	% of Tot Bill
Customer Charge	$ 15.00	$ 15	13%
Variable Energy Component	$ 0.03757	$ 31	27%
Fixed Power and Transmission Component	$ 0.04543	$ 38	33%
Fixed Distribution Component	$ 0.03860	$ 32	28%
Average Residential Customer (837 kWh/month)		$ 117	100%

Trico also has a wholesale power cost adjustor ("WPCA"). In this rate case, it will be rebased to include the current cost for wholesale power and transmission in the Trico base rates. In the future, it may be adjusted if Trico's wholesale power and transmission cost is increased above or decreased below the base wholesale power and transmission costs.

III. ACQUISITION AND RATE CASE TREATMENT OF DAFS.

Q. Why is Trico acquiring these DAFs from SWTC at this time?

A. Trico has contemplated purchase of the SWTC DAFs for a number of years. The original contracts between SWTC and its Members, including Trico, anticipated that all the Members of SWTC would have DAFs, however over time the contracts have changed making it easier for Members to own facilities that would have otherwise been SWTC DAFs. As a result, Trico is the only SWTC Member with any substantial DAFs. Additionally, Trico does not plan to have any new DAFs in the future. The tracking and administration of the costs and billing associated with the DAFs has and continues to be very complex and difficult for all parties involved. Trico also sees a benefit in acquiring ownership and control of the costs and cost allocation for facilities that are used for Trico and paid for by Trico. Most importantly, Trico wants to acquire the DAFs concurrently with a Trico rate case process so the carrying costs associated with the DAFs can be recovered through Trico's base rates, rather than through the Trico WPCA, as currently recovered.

Q. When will Trico acquire the DAFs?

A. Trico anticipates acquiring the DAFs at an approximate cost of $7,824,000 as adjusted, on the effective date of the ACC approval of the rates in this case. Since they will be acquired after December 31, 2014, the DAF purchase is a post-test year plant for purposes of this case. Even so, the cost to acquire DAFs, and its corresponding impacts on other expenses is known and measurable, and are used to serve existing customers as of the end of the test year. Trico has made the corresponding adjustments to its test-year revenues.

Q. Is the net impact of Trico acquiring the DAFs a benefit to its member-customers as to the revenue requirement?

A. Yes. While the purchase adds approximately $936,010 in expenses, it also has a corresponding reduction in the WPCA expense of $1,099,428, for an estimated net impact of $163,418 reduction in operating expenses. Therefore, the DAFs will provide a small, but meaningful net benefit to Trico and its Member-customers because of Trico's lower interest rates and margin than what SWTC currently charges Trico. Moreover, on a going forward basis, the purchase of the DAFs will save considerable administrative time and effort for all parties involved.

Q. What will be the impact on customer rates?

A. David Hedrick of Guernsey Engineers, Architects and Consultants (Guernsey) addresses the rate impacts of the DAFs purchase in his direct testimony. From a conceptual standpoint, however, customers will experience an increase in base rates (from the increase to rate base and depreciation expense); but this will be coupled with a reduction in costs from AEPCO and SWTC passed through to Trico via the Cooperative's WPCA. The net impact of the DAF purchase will result in a small reduction in rates for Trico customers.

IV. IMPACT OF RATE CASE ON FINANCIAL CONDITION.

Q. What are the resulting Debt Service Coverage ("DSC") and Times Interest Earned Ratio ("TIER") derived from Trico's request?

A. If approved, Trico's DSC would be 1.94 and its Operating TIER would be 2.00, which would be improved from its adjusted DSC and TIER of 1.70 and 1.57 respectively. Maintaining a strong DSC and TIER is necessary to meet the requirements set forth by the Rural Utilities Service ("RUS"), the primary lender for Trico. Trico's ability to acquire low-cost debt from RUS and from the National Rural Utilities Cooperative Finance Corporation depends on its maintenance of healthy DSC and TIER. Mr. Hedrick details the impact of Trico's rate request on DSC and TIER in his direct testimony.

Q. **Will the relief sought in this rate case allow Trico to make necessary capital expenditures ("CAPEX") over the next five years without jeopardizing its financial condition?**

A. Yes. The rate increase Trico is proposing will allow it to make necessary investments without jeopardizing its financial ratios. Trico anticipates investing approximately $65 million in plant additions over the next five years (through 2019). Mr. Hedrick details the impact of Trico's capital plan on its financial ratios in his testimony related to the Trico financial forecast in his direct testimony.

Q. **Would the proposed rate increase allow Trico to strengthen its financial base, maintain a healthy equity ratio and allow it to achieve all of the objectives in terms of providing safe and reliable service that you mentioned above?**

A. Yes. Trico's proposed increase in its revenue requirement would allow it an opportunity to earn a 6.33% return on its fair value rate base ("FVRB") of $ 175,076,536, which equates to an operating margin for Trico of $5,364,759. It will also allow the Cooperative to maintain desired cash levels of approximately 3% of total plant. Mr. Hedrick describes the financial impact of the rate case in more detail.

V. RATE DESIGN.

Q. **What are Trico's rate design objectives in this case?**

A. In this rate case, Trico is seeking to modify its rate design so that each of its Members pays a more equitable share of Trico's fixed costs. Trico's cost of service study indicates that there are discrepancies between classes with respect to the ratio of cost of service and the costs covered by that customer class. Moreover, Trico is now experiencing the significant issue of lost fixed cost recovery due to significant increases in DG deployment in its service area.

In moving towards a more equitable allocation of fixed cost recovery, Trico must balance many factors in its rate design. For example:

1. Trico seeks to reduce the amount of unrecovered fixed costs resulting from future DG systems and reduce the fixed cost recovery shift from DG Members to non-DG Members.
3. Trico desires to continue to encourage conservation and sustainable deployment of DG systems.
4. Trico seeks to better match the costs attributable to a customer class with the revenues recovered from that class.
5. Trico seeks to provide more accurate price signals to its Members, which will result in more efficient and financially stable operations for Trico.

In addressing these factors, Trico is seeking to balance its obligation to provide equitable treatment to all of its Members against the need to avoid significant rate shifts among classes in a single rate case. In this case, Trico is proposing to balance gradualism with providing proper price signals, affordability and fairness – all while seeking to incrementally move rates towards the actual costs of providing service per customer class.

Q. **What are the overarching rate design changes that Trico is proposing in this rate case?**

A. The primary rate design changes are:

1. Trico is proposing to recover fixed grid costs associated with its existing distributed generation within Trico's service territory by increasing the fixed monthly customer charge and decreasing the volumetric energy rate for all Members, including those with DG.

2. Trico is proposing a two-tiered inclining block rates for residential customers – Trico presently has a single volumetric rate.

3. Trico is proposing to a new net metering tariff to continue to encourage sustainable deployment of DG systems, by reducing but not eliminating the fixed cost shift and resultant subsidies to Members who install rooftop solar or other distributed generation after February 28, 2015.

4. Trico is adjusting both up and down revenue recovery from customer classes to better match the cost of service for the class.

Q. Why is Trico seeking to recover more of its fixed costs through the monthly customer charge?

A. There are several reasons. First, for residential Members, Trico currently recovers approximately 13% of its fixed costs through its monthly service charge versus 87% of fixed costs recovered through the variable per-kWh energy charge. In contrast, approximately 73% of Trico's total costs are fixed versus 27% being variable costs for the average residential customer. Increasing Trico's recovery of fixed costs through increased monthly customer charges takes a step toward better matching costs to charges. It also increases revenue stability for Trico. Even so, Trico is not proposing that monthly customer charges equal the fixed costs reflected in its cost of service study. Indeed, for residential Members, Trico expects to recover only 18% of its fixed costs through the fixed monthly customer charges.

Second, less dependence on fixed cost recovery through the volumetric energy (kWh) charges decreases the economic disincentive for the utility to promote conservation, energy efficiency ("EE") and distributed generation ("DG").

Third, increasing the percentage of recovery through the monthly customer charge also reduces the cost shift to non-DG Members from DG Members.

Q. What increase is Trico proposing to the standard residential monthly basic service charge?

A. Mr. Hedrick provides more detail as to all of Trico's rate design changes. In an effort to move towards more appropriate monthly basic service charges for the residential rate class, Trico proposes to increase residential customer charge from the current $15.00 per month to $20.00 per month for the standard residential customers when new rates are implemented. The proposed customer charge is still only approximately 25% of the total fixed cost associated with the average customer and demand-related charges identified by the Trico's cost of service study for the residential customer.

Q. Why is Trico proposing a two tier volumetric rate for the residential rate classes?

A. Trico is proposing a two-tier inclining rate block structure for residential Members, detailed in Schedule H-4. For the residential rate class, Trico proposes to reduce the energy charge to $0.117600 per kWh for the first 800 kWh, with the rate increasing to $0.127600 per kWh for usage over 800 kWh.

Trico believes this two tier rate will promote energy efficiency and help offset the impact of the increased customer charge on lower usage members (including DG Members who consume less energy from Trico).

Q. **What impact will these changes have on the residential customer class in terms of the percentage increase and the customer bill?**

A. Based on average monthly energy (kWh) usage, which is 837 kWh for the test year, Trico anticipates that it will collect approximately 4.11% more revenue under the standard residential customer class with proposed rates. About half of this increase in revenue is associated with the DAF purchase which has a corresponding reduction in revenue from the wholesale power and transmission. For the residential customer using an average of 837 kWh, that customer will incur an increase of approximately $1.96 – from $116.84 to $118.80 – or about a 1.68% increase.

Q. **Please describe the changes for Trico's time-of-use ("TOU") residential rate schedule.**

A. Trico proposes to increase the residential TOU monthly customer charge from $19.00 to $24.00, while reducing the energy charges for both on-peak and off-peak kWh usage. For on-peak, Trico proposes to reduce the on-peak energy charge to $0.19320 from $0.19000 and to reduce the off-peak energy charge to $0.07000 from $0.07320. Mr. Hedrick details the reasons for the TOU residential rate changes in his direct testimony.

Q. **Please describe the changes the Company is proposing for Trico's non-residential customers.**

A. Trico is proposing similar rate design changes for its commercial customers. The changes for general service customers are designed to more appropriately recover fixed costs in the fixed portion of rates.

Q. **What monthly charge is Trico proposing for non-residential customer classes?**

A. For GS1, GS2, and GS3 customers, Trico is proposing an increase to the basic service charges for the same reasons as discussed for the residential class. The proposed monthly customer charges will reflect an increase from the current $18.00 to the proposed $23.00 (for single phase) and from $26.00 to $31.00 (for three phase). For its GS4 customers, however, the basic service charge will remain at $500.

Q. What is the Company proposing for the non-residential energy rates?

A. Similar to its proposal for residential energy charges, Trico proposes to reduce its energy charges for its GS1, GS2, and GS3 customers, as set forth in Schedule H-3. Trico's changes in non-residential rate design are adjusting to the fact that the GS3 and GS4 rate classes are earning more than the system average rate of return. As a result GS3 reflects an overall decrease and GS4 has no change proposed.

Q. What about for Trico's non-residential TOU rates?

A. For Trico's General Service TOU rates, it is proposing to increase the customer charges to $29.00 from $24.00 (for single phase) and to $37.00 from $32.00 (for three phase), while reducing the energy charge to $0.066000 from $0.063750 for all kWh usage. Since Trico was earning more from the GS TOU rate class than its system average rate of return, the changes in rate design balance the reasons behind increasing the monthly customer charges with aligning the class rate of return with the cost of service study resulting in an overall small decrease for the average GS TOU customer.

Q. Is Trico proposing any changes to its Interruptible tariff?

A. Yes. Trico proposes to merge its current interruptible customers onto one tariff and freeze the tariff (i.e., not allow for any new customers to go onto the tariff) and increase the overall rate for the combined tariff. Further, the current tariff has proven ineffective and has not provided the anticipated benefits to Trico given our wholesale power charges are billed as a fixed charge now rather than as a demand rate. Additionally, this tariff has very labor intensive administrative requirements versus the limited benefits. Trico will seek to migrate the twelve Members that are on the tariff to other tariffs between now and Trico's next rate case.

Q. Is Trico proposing similar changes to its water pumping, irrigation, outdoor and street lighting rates, with regards to changes in the monthly charges and energy rates?

A. Yes. All the changes to those rates are reflected in the "H" schedules that are part of Trico's application.

Q. As part of its rate design changes, is Trico proposing to reset its wholesale base cost of purchased power and transmission?

A. Yes, to reflect the projected cost of power, Trico seeks to reset the base cost of purchased power to $0.081711 from $0.081638 per kWh (an increase of $0.0000730 per kWh).

Q. Are you sponsoring the revised tariffs, which reflect the rate design changes?

A. Yes. The tariffs are included in **Exhibit KC-1**.

VI. NET METERING TARIFF.

Q. Ms. Cathers, did Trico previously file an application to revise its Net Metering Tariff in Docket No. E-01461A-15-0057 filed on February 26, 2015?

A. Yes. In that proceeding, Trico explained the problem of growing unrecovered fixed costs and why Trico was proposing to amend its net metering tariff as an interim solution to the problem pending a full rate case.

Q. Trico, however, ultimately filed a notice of partial withdrawal of that application?

A. Yes. Given the opposition we faced from several intervenors, and Staff's position that the problem of unrecovered fixed costs due to distributed generation ("DG") was best addressed in a rate case, Trico ultimately decided to withdraw all but its request to adjust the avoided cost rate. The Commission approved the withdrawal request in Decision No. 75227 on August 26, 2015, and approved Trico's request to adjust the avoided cost rate to $0.03662 per kWh in Decision No. 75226 on the same date.

Q. In this rate case, is Trico proposing the same modification of its Net Metering Tariff that it proposed in Docket No. E-01461A-15-0057?

A. Yes. The proposed Net Metering Tariff is included in **Exhibit KC-2** (both the clean and redline to the current Net Metering Tariff).

Q. Please summarize the issue Trico is trying to address with the modified Net Metering Tariff.

A. Trico seeks to address the growing problem of unrecovered fixed costs associated with the rapid rise in DG system installations most notably occurring at the end of 2014. Trico has already incurred those fixed costs to provide electric service to all of its member-customers (both to those customers that have DG systems ("DG Members") and those that do not ("non-DG Members"). Annual DG applications had grown from 65 in 2011, to 114 in 2012, to 160 in 2013, to 465 in 2014. Specifically, Trico had experienced almost a threefold increase in the number of solar-DG facilities applications between 2013 and 2014. In December 2014 alone, Trico received 114 applications. It received 74 applications in January 2015 and 174 applications in February 2015. Between the time when the Application in that docket was filed and the cutoff of midnight on February 28, 2015, Trico received 99 applications.

Q. How many applications for DG installations has Trico received between March 1, 2015 and September 30, 2015?

A. The number of applications have returned to levels similar to what Trico experienced in 2013 and early 2014. During that time period (March 1, 2015 to September 30, 2015), Trico received 87 applications.

Q. Please summarize how the proliferation of DG systems and net metering has led to the increase in the amount of unrecovered fixed costs for Trico?

A. Essentially, when DG Members generate a substantial amount of their own power, they avoid paying for a portion of their allocated share of the fixed costs for maintaining the grid. Even so, the DG Members are continuing to use the generation plant, transmission and distribution facilities related to the grid either when they take energy from Trico, or when they provide excess energy from their DG systems to Trico. Further, the grid facilities provide ancillary benefits to DG Members, even when DG Members are solely using energy produced from their systems for their own use. Even though Trico is proposing to recover a higher percentage of fixed costs through the monthly customer charge, there will still be a significant percentage of fixed costs recovered through the volumetric energy charges. Thus, there will still be a significant percentage of fixed costs that will go unrecovered absent revisions to the Net Metering Tariff. In other words, while Trico is proposing to reduce the percentage of fixed costs recovered through the energy charge, this phenomenon will remain even if Trico's rate design is approved as proposed.

Q. Do you have a figure as to the total amount of fixed costs that Trico will not recover?

A. Yes. As of March 1, 2015, the total amount of annual fixed costs associated with net metered residential customers that is unrecovered is approximately $1,355,947 – which comprised of distribution fixed costs and wholesale power and transmission fixed costs associated with the proposed grandfathered DG systems.

Q. Can Trico recover any of its unrecovered fixed costs now through its current rate design?

A. While Trico does currently recover some its unrecovered fixed costs (associated with generation and transmission) that are shifted to non-DG Members through Trico's WPCA, it cannot recover the other distribution related fixed costs through its current rate structure. The lost margins reduce the amount of capital credits that would otherwise be available to the Trico Members between rate cases.

Q. Were Trico's current rates developed to accommodate this phenomenon?

A. No. Trico's base rates (specifically the per-kWh energy charge) approved in Decision No. 71230 were based on Members taking a certain amount of energy from the grid, so that Trico could have a reasonable opportunity to recover its revenue requirement. With more DG Members and with the rapid rise of DG systems interconnected in Trico's service territory, the result is Trico's current rates are not designed to recover its revenue requirement given this phenomenon.

Q. Please summarize Trico's proposal to revise its net metering tariff.

A. Trico proposes the following to revise the Net Metering Tariff for DG Members with applications received after February 28, 2015:

1. For energy generated by a DG Member's system that is used to serve the DG Member's load, the DG Member continues to benefit from a full retail rate offset for that energy.
2. For any *excess* energy that is delivered to Trico from the DG Member's system, Trico will provide a credit on the DG Member's bill each month for the excess generation

at Trico's avoid cost rate, which is currently $0.03662 per kWh (thus, no longer rolling excess generation from the DG Member's system month to month).

3. The DG Member will continue to pay Trico for any energy delivered from Trico at the tariff retail rate established in this case.

Trico's proposed change *only* affects the credit for excess generation from the DG Member's facility. Trico will still provide a credit on a net-metered DG Member's bill each month for the excess generation; but this will be at the Commission-approved avoided cost rate (currently $0.03662/kWh based on 2014 actual wholesale energy costs).

Q. Does the avoided cost rate better reflect the benefit that Trico and its Members obtain from the excess DG energy delivered to Trico by its DG Members?

A. Yes. The avoided cost is a more accurate calculation. In effect, the excess energy reduces the energy that Trico must obtain to serve its load. Trico still has the same fixed costs for its distribution network and the same wholesale fixed charges – the excess DG energy does not reduce those costs. And Trico must continue to be able to provide safe and reliable electric service 24 hours a day.

In fact, the current avoided cost rate is higher than any benefit Trico receives from the excess DG energy. Moreover, Trico incurs additional costs from the two way interconnection required by DG systems, such as reliability, reserves, frequency control, voltage control, and redundancy. As set forth in Mr. Hedrick's testimony, the energy portion of Trico's volumetric rate is less than the avoided cost rate ($0.03662/kWh vs. $0.03080/kWh). This is because the approved avoided cost rate is based on actual, historical costs and the proposed unbundled energy rate is based on an adjusted test year, which reflects changes that have reduced Trico's wholesale cost for energy.

Finally, Trico's Members should not be obligated to pay more for the excess DG energy than what it is worth to Trico. Given how Trico obtains and pays for wholesale energy, the excess energy from DG Members provides no benefit to Trico and its Members beyond the avoided cost.

Q. Does Trico believe that crediting excess energy at avoided cost will better encourage customers to properly size their solar DG systems?

A. Yes. While the net-metering rules allow for sizing up to 125% of peak load, Trico believes that systems should be sized to address DG Members base load. Net metering Members under the proposed new net metering tariff will receive the retail rate for generation that serves their load and receive the avoided cost rate for any generation that is in excess of their load, which will provide a price signal to size their DG system to match their load. Trico should not have to acquire excess energy from an over-sized solar DG system at a rate four times higher than the cost from other sources. The new approach will thus encourage Members to better match the size of their rooftop system (and its production) to actual load and usage over time.

Q. Will the impacts of the new net-metering tariff be significantly different for those Members that install rooftop solar systems better matching their usage during the year?

A. No. If the Member installs a system that better matches their instantaneous usage over the course of the year, then the impact of the new tariff versus the current tariff will be small. Those Members will likely see a subsidy similar to what they would have enjoyed under the current net-metering tariff. Only those Members that install larger systems that generate far more energy than the Member uses for large portions of the year will see (on average) about a 50% reduction in subsidy with the proposed net net-metering tariff versus the current tariff. Of course, the amount of reduction depends on the particular

DG Member's usage pattern, and could vary significantly from customer to customer. Trico has observed Members installing larger systems recently, so this issue is one Trico currently faces.

Q. Is Trico proposing to maintain the cutoff of midnight on February 28, 2015 as part of its proposal in this rate case?

A. Yes. Further, and in accordance with the Commission's orders in Decision No. 75227, Trico has: (1) provided notice in its DG interconnection application materials; and (2) on its website under renewable programs – that it has proposed to maintain the same grandfathering date of March 1, 2015 for when the proposed revised Net Metering Tariff would take effect.

Q. How will the revisions to the Net Metering Tariff address the unrecovered cost problem posed by DG system proliferation and net metering?

A. In concert with the rate design changes, new DG Members will pay for a portion of fixed costs of Trico's grid services that is closer to what other Members pay for the same safe and reliable power services. But even with all of the proposals, new DG Members will still not pay as much as non-DG Members for the use of the grid. Further, the two-tier inverted block rate design for residential energy charges will reduce the impact on DG Members to the extent they are lower-use customers. Even so, the proposed revisions to the Net Metering Tariff coupled with the proposed rate design changes will reduce the amount of unrecovered fixed costs and the cost shift to non-DG Members from new DG Members to more tolerable levels.

Q. What will be the reduction in monthly lost fixed costs for the average DG Member under the new Net Metering Tariff in combination with the rate design changes Trico proposes?

A. Based on the average new DG Member, the lost fixed cost associated with DG Members will drop from about $83.34 per month to about $38.38 per month. Mr. Hedrick explains this calculation in more detail in his testimony. Although this reduction helps mitigate the lost fixed cost issue, it does not fully resolve it. The average new DG Member will still be receiving a subsidy of almost $40 per month. However, Trico believes this is an appropriate first step towards reduced subsidies and more equitable recovery of fixed costs from its Members, while maintaining a viable distributed solar program.

Q. Will there be any additional costs imposed onto new DG Members?

A. No. Trico is still not proposing a separate "net metering charge" for new DG Members. We are not proposing to place new DG Members on another rate tariff in effect, or create a new tariff for new DG Members. We are also not proposing any new demand-based rate (per-kW) charge for new DG Members as part of this case either.

Q. Why should the Commission adopt changes to the net metering tariff in this rate case if Trico is also proposing rate design changes to address the problems of the cost-shift and unrecovered fixed costs?

A. The Commission should adopt the net metering tariff changes because the current tariff is contributing significantly to the problem of unrecovered fixed costs. The rate design changes alone will not reduce the unrecovered fixed cost problem going forward enough to maintain the current Net Metering Tariff. The heart of the problem remains that the excess energy credit at the full retail rate ignores the DG Members' continuing use of Trico's grid. The rate design changes (namely, increasing the customer charge) together with the changes to the Net Metering Tariff will work hand-in-hand to reduce the going forward unrecovered fixed cost and cost-shift problems specifically caused by DG proliferation enough to a manageable level.

Q. Is Trico re-urging its request for a partial waiver of the Net Metering Rules to the extent necessary to approve the revisions to its Net Metering Tariff?

A. Yes. Crediting DG Members for excess energy at avoided cost and not rolling such energy to offset future usage varies from what is established in A.A.C. R14-2-2306. But Trico believes it is in the public interest to do so because the new net-metering tariff still provides a benefit to Trico's DG Members by crediting those Members the energy utilized to serve their load at the retail rate and for excess energy at a fairer amount, while also significantly and directly mitigating the future lost revenue and the resulting cost-shift problem presented by the current net-metering tariff.

Q. In the last proceeding to modify the net metering tariff, Trico faced significant opposition from certain parties representing certain DG interests. Is Trico trying to eradicate additional DG from being installed in its service territory?

A. No. Trico supports continuing deployment of DG in its service area, but that deployment needs to be sustainable and not unduly harmful to its Members as a whole. The current rate design combined with the current Net Metering Tariff Trico has created is simply attempting to address the issue in a manner that is in the best interests of its Members as a whole.

VII. SUN FARM MONTHLY TARIFF.

Q. Is Trico proposing a new Sun Farm Monthly Tariff?

A. Yes. Trico's Community Solar Project – the SunWatts Sun Farm – remains operational and Trico members can purchase certain increments up to their average monthly kWh energy usage in the last 12-month period. However, Trico is now proposing a new option that requires no up-front dollars, by allowing customers to purchase panel output through a monthly solar energy charge. This solar energy charge will stay fixed for a 20-year term. Trico customers, under this option, can purchase whole-panel increments up to, but not to exceed, their minimum monthly kWh energy usage in the last 12 months.

Q. Why is Trico proposing this new Sun Farm Monthly Tariff?

A. This option will provide an opportunity for Members to participate in our Sun Watts community solar program even if they do not want (or are unable) to pay an upfront cost for participation. The proposed Sun Farm Monthly Tariff is included in **Exhibit KC-3**.

VIII. RULES, REGULATIONS AND LINE EXTENSION POLICY.

Q. Why is Trico proposing changes to its RRLEP?

A. Trico is proposing modifications to its RRLEP to update provisions to meet current operational needs, better align them with our customers' needs and ultimately provide better customer service. Trico's RRLEP predate the Arizona Administrative Code ("Code") that the Commission adopted in 1982, but have been amended on multiple occasions. Several of Trico's proposed changes are to better align with the Code, but also to modernize the RRLEP and better align them with current business practices. In addition, some of the proposed revisions are intended to clarify and reorganize certain provisions of the RRLEP to make them easier to read and understand and to reduce potential confusion.

Trico is also proposing revisions to its Line Extension Policy, which is a part of its RRLEP.

The revised RRLEP (both redlined and clean versions) are attached to my testimony as **Exhibit KC-4**.

Q. Please summarize Trico's existing Line Extension policy.

A. In Decision No. 71230, the Commission approved Trico's proposal to eliminate the free footage allowance for line extensions, which was intended to improve its ability to recover costs associated with then-anticipated continuation of above-average growth in Trico's service territory. Eliminating free footage was necessary at that time to help improve its equity capitalization ratio and to avoid the potential of violating its debt covenants with respect to DSC and TIER. It also conformed to Commission decisions for other electric utilities at that time.

Q. What is Trico proposing to change as part of this case?

A. Trico is proposing to reinstate a line extension allowance for all customer classes with the exception of large commercial and industrial classes. For each new permanent residential customer the allowance proposed is: (1) $1,500 per line extension for each new permanent residence; and (2) the cost of special equipment (such as a transformer and/or meter) that usually averages approximately $500. This results in a residential line extension allowable credit of up to about $2,000. Trico is also proposing to amend its RRLEP to update and clarify certain provisions.

Q. Why is Trico proposing those particular amounts for line extensions?

A. While the cost of service for Trico supports a $2,833 allowable investment for permanent residences (based on a 35-year revenue stream), Trico is seeking to balance providing some allowance for new residences together with the impacts to its existing member-customers. Mr. Hedrick provides detail on the parameters of an appropriate allowances.

Q. Why is Trico proposing to reinstate a line extension allowance at this time?

A. Growth has slowed in Trico's service area, so Trico is no longer facing enormous capital demands, particularly in its distribution system/backbone facilities, if some line extension allowance is provided. Encouraging growth in Trico's predominantly-rural service territory can benefit existing customers through economies of scale over the long term. Moreover, Trico's service area is adjacent to Tucson Electric Power's service area and TEP has reinstituted a free footage allowance. Trico believes it is appropriate to have an allowance so that development does not happen primarily in the adjacent TEP area.

Q. Why is Trico not proposing to simply reinstate a free-footage allowance for line extensions?

A. Given the diverse geography of Trico's service area, line extension costs can vary significantly from place to place on a per foot basis. A set allowance is a more equitable approach for Trico. Also, because of the price volatility of equipment and material used for line extensions, the fixed dollar amount will better maintain an allowance consistent with the Cooperative's cost of service.

Q. Ms. Cathers, why should the Commission reinstate a free dollar allowance for line extensions, when Trico is seeking to reduce the subsidy to DG Members in the same case?

A. New Member connections results in increased revenues for Trico. A new residential connection provides about $77 per year in margin on average. Over a 35 year life of the connection, the revenues exceed the allowance. The calculated allowance provides that Trico and its Members will benefit from the increase revenues. On the other hand, DG customers are now avoiding paying for infrastructure that was already installed in order to provide safe and reliable service to that Member. And the amount of lost revenue is over

$1,000 per year for the average DG Member. Trico has no way to fully recoup that lost revenue.

Q. Does this conclude your Direct Testimony?

A. Yes.

Exhibit KC-1

TRICO ELECTRIC COOPERATIVE, INC.

Marana, Arizona

STANDARD OFFER TARIFFS

Effective

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ELECTRIC RATES

STANDARD OFFER TARIFF

INDEX

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ____________

STANDARD OFFER TARIFF

RESIDENTIAL SERVICE
SCHEDULE RS1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Residential Service Rate (RS1) is applicable for residential purposes in individual private dwellings and in individually metered apartments, condominiums, and similar residential units, when such service is supplied at one premise through one point of delivery and measured through one meter.

Not applicable to resale or standby. This rate may be applicable to three (3) phase service used for domestic purposes only. Three phase service is required for motors of an individual rating capacity of 10 H.P. or more.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, or 120/208 volt three phase

Monthly Rate

STANDARD RATE RS1	Power Supply		Distribution Charges					Total Rate
			Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)								
Single-Phase			$5.23	$0.98	$6.33	$7.46	$20.00	$20.00
Three-Phase			$5.23	$0.98	$6.33	$7.46	$20.00	$20.00
Energy Charge ($/kWh)								
First 800 kWh/month	$0.0770					$0.0406	$0.0406	$0.1176
Over 800 kWh/month	$0.0870					$0.0406	$0.0406	$0.1276

RESIDENTIAL SERVICE
SCHEDULE RS1

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

RESIDENTIAL TIME OF USE SERVICE
SCHEDULE RS2TOU

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Residential Time of Use Service Rate (RS2TOU) is applicable for residential purposes in individual private dwellings and in individually metered apartments, condominiums, and similar residential units, when such service is supplied at one premise through one point of delivery and measured through one meter.

Not applicable to resale or standby. This rate may be applicable to three (3) phase service used for domestic purposes only. Three phase service is required for motors of an individual rating capacity of 10 H.P. or more.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, or 120/208 volt three phase

Monthly Rate

TIME-OF-USE RATE RS2TOU	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single Phase		$11.18	$0.98	$6.33	$5.51	$24.00	$24.00
Three Phase		$11.18	$0.98	$6.33	$5.51	$24.00	$24.00
Energy Charge ($/kWh)							
On-Peak kWh	$0.1224				$0.07550	$0.07550	$0.1979
Off-Peak kWh	$0.0624				$0.01550	$0.01550	$0.0779

RESIDENTIAL TIME OF USE SERVICE
SCHEDULE (RS2TOU)

Definition of On-Peak

April 1 through October 31: For this rate schedule, on-peak hours are 1:00 p.m. to 9:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

November 1 through March 31: For this rate schedule, on-peak hours are 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

RESIDENTIAL TIME OF USE SERVICE
SCHEDULE (RS2TOU)

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

***Definition of Holidays**

Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. If a Holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a Holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Less Than 10 kW Rate (GS1) is applicable for single and three phase service for more than one residence from a single metering point, where the service is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters and has a monthly demand of less than 10 kW. All service shall be delivered at a single service location. The Cooperative reserves the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase, or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply		Distribution Charges					Total Rate
			Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)								
Single Phase			$5.54	$0.98	$6.33	$10.15	$23.00	$23.00
Three Phase			$5.54	$0.98	$6.33	$18.15	$31.00	$31.00
Energy Charge ($/kWh)	$0.0758					$0.0579	$0.0579	$0.1337

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS2
GENERAL SERVICE 10 KW TO 200 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service 10 kW to 200 kW Rate (GS2) is applicable for single and three phase service where the service is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters; the monthly billing demand is greater than 10 kW but less than 200 kW and has an average monthly load factor of 30% or less based on twelve months of actual consumption history, or in the absence of such history, on service load characteristics. All service shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single Phase		$5.54	$0.98	$6.33	$10.15	$23.00	$23.00
Three Phase		$5.54	$0.98	$6.33	$18.15	$31.00	$31.00
Billing Demand Charge* ($/kW/Month)							
First 10 kW/month	no charge						no charge
Each kW over 10 kW/month	$4.50						$4.50
Energy Charge ($/kWh)	$0.0944				$0.0520	$0.0520	$0.1464

*The Billing Demand Charge shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

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Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS3
GENERAL SERVICE LESS THAN 12,000 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Less Than 12,000 kW Rate (GS3) is applicable for single and three phase service where the service is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters; the monthly billing demand is between 10 kW and 11,999 kW. All service shall be delivered to a single service location. The Cooperative reserves the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$10.15	$23.00	$23.00
Three-Phase		$5.54	$0.98	$6.33	$18.15	$31.00	$31.00
Billing Demand Charge* ($/kW/Month)	$15.00				$3.00	$18.00	$18.00
Energy Charge ($/kWh)	$0.0401				$0.0348	$0.0348	$0.0749

*The Billing Demand Charge shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month.

GENERAL SERVICE
SCHEDULE GS3
GENERAL SERVICE LESS THAN 12,000 KW

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Power Factor

The Customer shall maintain power factor of not less than 95% leading or lagging. The Cooperative shall have the right to measure such power factor at any time. Should such measurement establish that the power factor of the Customer is less than 95% leading or lagging, the Customer shall upon 60 days written notice correct such power factor to 95%. If not timely corrected, the Cooperative shall have the right to increase the kWh for billing purposes by one percent for each one percent of power factor below 95% leading or lagging.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

GENERAL SERVICE
SCHEDULE GS3
GENERAL SERVICE LESS THAN 12,000 KW

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

GENERAL SERVICE TIME OF USE - EXPERIMENTAL
SCHEDULE GS-TOU

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served. This rate is limited to the first 100 qualified Customers.

Application

The General Service Time of Use Rate – Experimental (GS-TOU) is applicable for single and three phase service for any Customer who would otherwise be eligible for either the General Service 1 (GS1), General Service 2 (GS2) or General Service 3 (GS3) rate. All service shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo) Single-Phase Three-Phase		 $11.18 $11.18	 $0.98 $0.98	 $6.33 $6.33	 $10.51 $18.51	 $29.00 $37.00	 $29.00 $37.00
Billing Demand Charge* ($/kW/Month)	$0.00				$5.95	$5.95	$5.95
Coincident Demand Charge** ($/kW/Month)	$29.50				$0.00	$0 .00	$29.50
Energy Charge ($/kWh)	$0.0460				$0.0200	$0.0200	$0.0660

GENERAL SERVICE TIME OF USE - EXPERIMENTAL
SCHEDULE GS-TOU

Minimum Monthly Charge

The greater of the following:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

Power Factor

The Customer shall maintain power factor of not less than 95% but not greater than unity. The Cooperative shall have the right to measure such power factor at any time. Should such measurement establish that the power factor of the Customer is less than 95% or greater than unity, the Customer shall upon 60 days written notice correct such power factor to 95% to unity. If not timely corrected, the Cooperative shall have the right to increase the kWh for billing purposes by one percent for each one percent of power factor below 95% or above unity.

Billing Demand

The billing demand shall be the maximum kilowatt demand established by the Customer for any period of 15 consecutive minutes during the month for which the bill is rendered, as indicated or recorded by a suitable metering device, but not less than the highest billing demand in the previous eleven months.

Coincident Demand

The Coincident Demand is the Customer's monthly metered demand as recorded by suitable metering device at the time of the SWTC peak.

Other Provisions

The Customer will be provided by the Cooperative with information concerning historical SWTC monthly peak dates and times.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

GENERAL SERVICE TIME OF USE - EXPERIMENTAL
SCHEDULE GS-TOU

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Greater Than 2000 kW and Less Than 10,000 kW Rate (GS4) is applicable for three-phase service for all electric service used for Commercial, Business, Professional and Industrial peak loads in excess of 2,000 kW but not to exceed 9,999 kW which are supplied at one point of delivery and measured through one meter. Existing Customers served by this tariff may continue to take service under this tariff if they met tariff eligibility requirements prior to the effective date. Service under this rate tariff cannot be interrupted intentionally to avoid demand charges.

Alternately, at the Customer's option it may take delivery at multiple delivery points with one primary metering point provided that the Customer pays the Cooperative a non-refundable contribution in aid of construction or, at the Cooperative's discretion, the Cooperative will install the facilities required to serve multiple delivery points and the Customer will pay for such facilities pursuant to a monthly facilities charge assessed based upon a cost analysis to serve the load. The Cooperative has the right to meter in the most practicable manner, either primary or secondary voltage. Service is available only if the Cooperative has adequate facilities to serve the Customer or if adequate facilities can be built at the Customer's expense to provide such service.

Type of Service

At available transmission or distribution voltages determined by the Cooperative. Where service of the type desired by the Customer is not already available at the point of delivery, additional charges under the Cooperative's RRLEP and special contract arrangements may be required prior to service being furnished.

Monthly Rate

a. Customer Charge:

Meter Cost	$450.97 per month
Meter Reading	$ 0.98 per month
Billing	$ 6.33 per month
Access	$ 41.72 per month
Total Customer Charge	$500.00 per month

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

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b. Distribution Demand Charge at the Applicable Metering Point:

Transmission Delivery	$0.21 per kW of Billing Demand, or
Distribution Substation Delivery	$1.75 per kW of Billing Demand, or
Distribution Primary Delivery	$7.19 per kW of Billing Demand, or
Distribution Secondary Delivery	$7.70 per kW of Billing Demand

Definition of Service Levels
Transmission Delivery is defined as service taken at 69 kV or higher.

Substation Delivery is defined as service taken directly from the low side bus of the distribution substation or where Customer has requested that multiple points of delivery be metered at the low side bus of the distribution substation. Where multiple delivery points are metered at the low side bus of the distribution substation, the Customer will be charged an additional facilities charge for the Cooperative-owned, operated or maintained facilities on the Customer side of the meter

Distribution Primary is defined as service taken at standard distribution voltages where the Customer owns the final distribution transformation equipment or where the Customer has requested that multiple points of delivery be metered at a single primary metering location. Where multiple delivery points are metered at a single primary metering location, the Customer will be charged an additional facilities charge for the Cooperative-owned, operated or maintained facilities on the Customer side of the meter.

Distribution Secondary is defined as service taken at standard secondary voltages where the Cooperative owns the final distribution transformation equipment.

c. Wholesale Power Cost:
The Wholesale Power Cost shall be the cost of electricity to serve the Customer, including but not limited to, capacity, energy, transmission, ancillary services and fuel charges for the current billing period plus adjustments applied to the current monthly billing to account for differences in actual purchased electricity costs billed in previous periods from all providers who provide services in connection with the Wholesale Power Cost. The Wholesale Power Cost will be calculated using the billing units defined in the same manner as defined in the wholesale rate to the Cooperative, including any ratchet provisions in the wholesale rate. The Customer's billing units may be adjusted for line losses, as determined by the Cooperative, to calculate the Customer's power cost at the wholesale supplier's metering point to the Cooperative.

d. Facilities Charge:
An additional monthly charge for the provision of distribution facilities as determined by the written Agreement between the Cooperative and the Customer.

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

Determination of Facilities Billing Demand

The Billing Demand for purposes of determining the Distribution Demand Charge will be the greater of: (1) the contract demand as defined in the Agreement for Electric Service, (2) the highest maximum thirty-minute demand established during the current and previous eleven billing periods, or (3) 2,000 kW.

Minimum Monthly Charge

The greater of the amount specified in the written Agreement between the Cooperative and the Customer or the sum of the monthly Customer Charge, Distribution Demand Charge, and Facilities Charge, not including any wholesale power cost adjuster or any other adder approved by the Arizona Corporation Commission.

Power Factor

The Customer shall maintain power factor at the time of the Customer's maximum demand as close to unity as possible. The Cooperative shall have the right to measure such power factor at any time during the billing period. In the event the power factor measured at the time of the Customer's maximum demand is less than 95% lagging or leading, such maximum shall be adjusted for billing purposes by dividing such maximum measured demand by the measured power factor multiplied by 0.95.

Tax Adjustment

To each of the charges computed in this Tariff, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues and/or the price or revenue from the electric distribution, capacity and energy and transmission and ancillary services, sold and/or the volume of energy purchased for sale and/or sold hereunder.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions, or use of service, the Cooperative will assist in determining if a change in rate schedule is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

All electric service provided pursuant to this Tariff shall be set forth in a written agreement between the Cooperative and the Customer. Any service provisions that are different from the provisions of the Tariff shall be set forth in a written agreement that will require the approval of the Arizona Corporation Commission. The written agreement shall contain, among other provisions, provisions for a Contract Demand, Minimum Monthly Charge and a Facilities Charge to cover capital costs and operation and maintenance costs, if applicable. Should the Customer request service at the Transmission Delivery rate, and should the line connections be made directly with the lines of the Cooperative's transmission

GENERAL SERVICE
SCHEDULE GS4
GENERAL SERVICE GREATER THAN 2,000 KW AND LESS THAN 10,000 KW

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provider, then the contract may become a three-party contract to cover the provisions required by the Cooperative's transmission provider.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

WATER PUMPING SERVICE
SCHEDULE WP (FROZEN)

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Water Pumping Service Rate (WP) is applicable to all electric pump installations that are furnishing water to Customers on a commercial basis prior to effective date. All water pumping Customers connected after the effective date will be placed on applicable General Service Rate. All service to an installation shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$10.15	$23.00	$23.00
Three-Phase		$5.54	$0.98	$6.33	$18.15	$31.00	$31.00
Energy Charge ($/kWh)	$0.104				$0.0395	$0.0395	$0.1435

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer.

WATER PUMPING SERVICE
SCHEDULE WP (FROZEN)

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

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Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

IRRIGATION SERVICE
SCHEDULE IR1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Irrigation Service Rate (IR1) is applicable to all single and three phase irrigation pumping installations of ten (10) horsepower pumps or larger. This rate is only applicable to farm use. Not applicable where water is sold to other Customers, not for resale, breakdown or standby or auxiliary service. All service to an installation shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$10.15	$23.00	$23.00
Three-Phase		$5.54	$0.98	$6.33	$18.15	$31.00	$31.00
Energy Charge ($/kWh)	$0.0817				$0.0603	$0.0603	$0.1420

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

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Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

TIME OF DAY PUMPING SERVICE
SCHEDULE TODP

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Time of Day Pumping Service Rate (TODP) is applicable to all water pumping installations of ten (10) horsepower pumps or larger. All service to an installation shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

TIME OF DAY RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.54	$0.98	$6.33	$10.15	$23.00	$23.00
Three-Phase		$5.54	$0.98	$6.33	$18.15	$31.00	$31.00
Billing Demand Charge ($/kW)* On-Peak	$16.00						$16.00
Billing Demand Charge ($/kW)** Off-Peak	$0.00				$1.75	$1.75	$1.75
Energy Charge($/kWh)							
On-Peak	$0.0680				($0.0065)	($0.0065)	$0.0615
Off-Peak	$0.0680				($0.0065)	($0.0065)	$0.0615

*The Billing Demand Charge On-Peak shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month during the on-peak period of that billing month.

TIME OF DAY PUMPING SERVICE
SCHEDULE TODP

**The Billing Demand Charge Off-Peak shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month during the off-peak period of that billing month.

Definition of On-Peak

April 1 through October 31: For this rate schedule, on-peak hours are 1:00 p.m. to 9:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

November 1 through March 31: For this rate schedule, on-peak hours are 6:00 a.m. to 10:00 a.m., and 6:00 p.m. to 10:00 p.m., Monday through Friday. All other hours, including Saturday, Sunday and *Holidays, are considered to be Off-Peak.

Metering Cost

The Customer shall pay the Cooperative, prior to installation, any cost for the Time-of-Day Energy and Demand Meter, which cost exceeds the metering cost that would be incurred by the Cooperative for such a pumping installation without a Time-of-Day Meter.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material

TIME OF DAY PUMPING SERVICE
SCHEDULE TODP

changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

***Definition of Holidays**

Holidays are defined as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. If a Holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a Holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

LIGHTING SERVICE
SCHEDULE OL1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Lighting Service Rate (OL1) is applicable to Cooperative owned and operated lighting facilities generally on private property and otherwise subject to local jurisdictional lighting ordinances.

Type of Service

Single-phase, unmetered, 60 hertz, at one standard voltage 120/240.

Monthly Rate

For the Cooperative owned, operated and maintained lighting, the monthly rate shall be as follows, based on estimated average monthly usage for unmetered lights:

Cooperative-Owned and Maintained Lighting Service	Power Supply		Distribution			Total Rate
			Billing	Access	Total	
Security Lights	$4.33			$7.67	$7.67	$12.00
Additional Poles for Lights				$10.90	$10.90	$10.90

150 Watt HPS	$3.68			$8.14	$8.14	$11.82
250 Watt HPS	$6.13			$6.37	$6.37	$12.50
400 Watt HPS	$9.81			$2.89	$2.89	$12.70
55 Watt LPS	$2.21			$9.19	$9.19	$11.40
90 Watt LPS	$2.21			$9.19	$9.19	$11.40
135 Watt LPS	$3.68			$8.14	$8.14	$11.82
100 Watt HPS	$2.45			$9.02	$9.02	$11.47

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period. The Cooperative will advise the Customer of the applicable inspection requirements, if any, required by the jurisdictional authority in which the light is proposed.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff does not exist, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services. A Service Availability Charge shall be paid by the Customer who elects to have the lighting service disabled but remain connected in place. Lights disabled or disconnected for a period of 6 consecutive months are considered idle or inactive, and shall be subject to inspection requirements prior to reactivation depending on the jurisdictional authority.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
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Marana, Arizona 85658
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Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

STREET LIGHTING SERVICE
SCHEDULE SL1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Street Lighting Service Rate (SL1) is applicable for lighting public streets, alleys, thoroughfares, public parks and playgrounds within the Cooperative's Certificated Area as contracted with city, town or other governmental entities. This tariff applies to Customer provided lighting facilities which are operated by the Cooperative.

General Maintenance

The Cooperative shall have no duty to inspect the facilities to determine if any lights of any of the facilities operated by the Cooperative are not functioning or satisfactorily functional. The duty of inspecting the functioning state of the lights is the obligation of the Customer. When the Cooperative is properly notified by the Customer that such lights or other facilities are not functioning or satisfactorily functioning, the Cooperative within a reasonable time will maintain such lights or facilities.

Light or Pole Numbering

Customer will provide and affix physical numbering of all lights on the light standard or lighting poles for all installations in order to facilitate accurate inventory, reporting, and locating. Affixed numbering is required prior to energizing facilities. Numbering must be durable, weather proof, and be legible from the ground and shall follow the numbering scheme the Cooperative will provide to the Customer.

Maintenance By The Cooperative

Rates include all labor and material necessary for the operation, inspection, cleaning, and/or replacement by the Cooperative of lamps, photocells and standard fixture glassware. Replacement is limited to certain glassware such as is commonly used and manufactured in reasonably large quantities which the Cooperative is able to obtain in a reasonable timeframe and reasonable cost for the Customer furnished lighting, based on the manufacturer's data provided by the Customer or already on record with the Cooperative. The Cooperative will invoice the Customer, at the Cooperative's rate, the cost for all other replacement material (not labor) used such as poles, fixtures, ballasts, non-standard glass, wiring or fusing type devices.

Installation and Maintenance by Customer

The Customer is responsible for all the supply, installation and materials, including, but not limited to, foundations, metal light standards, approved light poles if wood, fixtures, secondary wiring, boxes, trenching, backfill, shading, conduit system, fusing, circuit breakers and electrical panels, from the Cooperative's designated distribution facilities to the point of delivery at each of the Customer's street light facilities. The point of delivery is defined for the tariff as the point of connection at the base of the pole when the Cooperative's source is underground or at the drip loop at the top of the pole when the Cooperative's source is overhead. This includes providing all applicable design, engineering, drawings, plans, permits and inspections related to the Customer's installation and which have been approved by the Cooperative. The Customer is responsible for all maintenance and repair of lighting circuitry beyond the point of delivery, damage repairs or replacements to lighting foundations, and damage repairs or replacements to any underground boxes and for all trench stability and backfills.

Type of Service

Single-phase, unmetered, 60 hertz, at one standard voltage 120/240.

Monthly Rate

For the Customer owned and Cooperative maintained street lighting system including lamps and glass replacements, subject to the Customer's responsibility set forth above, the monthly rate shall be as follows, based on estimated average monthly usage for unmetered lights:

Customer-Provided and Cooperative-Maintained Lighting Service	Power Supply		Distribution			Total Rate
			Billing	Access	Total	
150 Watt HPS	$3.68			$7.08	$7.08	$10.76
250 Watt HPS	$6.13			$4.63	$4.63	$10.76
400 Watt HPS	$9.81			$7.96	$7.96	$17.77
55 Watt LPS	$2.21			$5.42	$5.42	$7.63
90 Watt LPS	$2.21			$10.07	$10.07	$12.28
135 Watt LPS	$3.68			$7.08	$7.08	$10.76
180 Watt LPS	$4.41			$8.78	$8.78	$13.19
100 Watt HPS	$2.45			$8.31	$8.31	$10.76
Standard Wood Pole (25' – 30')*				$1.38	$1.38	$1.38
10' - 20' Metal Pole				$3.64	$3.64	$3.64
21' – 30' Metal Pole				$4.34	$4.34	$4.34
31' – 40' Metal Pole				$4.34	$4.34	$4.34

*Measured from the top of foundation base to top of metal pole or from existing grade to top of wood pole

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

STREET LIGHTING SERVICE
SCHEDULE SL1

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff does not exist, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services. A Service Availability Charge shall be paid by the Customer who elects to have the lighting service disabled but remain connected in place. Lights disabled or disconnected for a period of 6 consecutive months are considered idle or inactive, and shall be subject to inspection requirements prior to reactivation depending on the jurisdictional authority.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

INTERRUPTIBLE SERVICE
SCHEDULE IS1 (FROZEN)

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served. The Interruptible Service Rate (IS1) is applicable to Customers only prior to the effective date of this tariff. No new Customers will be accepted on this tariff after the effective date of the tariff.

Application

The Interruptible Service for Commercial and Industrial rate (IS1) is applicable for General Service Customers for Commercial, Business, Professional, and Industrial, Irrigation Pumping and Water Pumping loads from in excess of 10 kW and a monthly load factor greater than 30% in any month within a 12 month period. The Cooperative shall have the right to meter the installation in the most practical manner, either primary or secondary voltage, and to determine the number of meter (service) points at any installation.

In the event the Customer has metered demand at the time of the Southwest Transmission Cooperative, Inc. (SWTC) or its successor organization, peak more than twice in a calendar year, the Cooperative may disconnect the controlling device and discontinue Interruptible Service. A Customer removed for non-compliance may not be considered for Interruptible Service for a minimum of eighteen (18) months.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase, or 277/480 volt three phase.

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$11.18	$0.98	$6.33	$17.51	$36.00	$36.00
Three-Phase		$11.18	$0.98	$6.33	$26.51	$45.00	$45.00
Coincident Demand Charge* ($/kW/Month)	$19.50						$19.50

INTERRUPTIBLE SERVICE FOR COMMERCIAL AND INDUSTRIAL SCHEDULE IS1 (FROZEN)

Billing Demand Charge** ($/kW/Month)	$0.00	$1.75	$1.75	$1.75
Energy Charge ($/kWh)	$0.0653	$0.02220	$0.02220	$0.0875

*The Coincident Demand Charge is applied to the Customer's monthly measured demand as recorded by suitable metering device at the time of the SWTC peak or if Trico does not initiate control at the proper time to avoid the SWTC billing peak or if the control system does not properly function to disconnect the load, the Customer will not be billed the Coincident Demand Charge. However the Customer will be billed the Coincident Demand Charge using the Customers demand from the time of the last successful Trico initiated control.

** The Billing Demand Charge shall be applied to the Customer's monthly metered demand as recorded by suitable metering device at the time of the Customers highest 15 minute interval demand for the billing month.

Metering Cost

The Customer shall pay the Cooperative, prior to installation, any cost for the time-of-use and demand meter, special metering or control equipment which cost exceeds the cost that would be incurred by the Cooperative for non-interruptible service.

Control and Metering

The service will be interrupted anytime Trico anticipates the possibility of a maximum monthly peak kilowatt demand. Control will be initiated by Trico and the control signal will be via radio-controlled equipment or notification will be provided to the Customer by telephone or some other normal method of load control. The Cooperative will not interrupt more than twelve times in any given month.

The account will be metered with a time-of-use/demand meter to enable Trico to accurately measure the Customer's kW Demand during control periods and at the time of monthly SWTC billing peak. If Trico does not initiate control at the proper time to avoid the SWTC billing peak or if the control system does not properly function to disconnect the load, the Customer will not be billed the Coincident Demand Charge. However the Customer will be billed the Coincident Demand Charge using the Customers demand from the time of the last successful Trico initiated control.

An Interruptible Service Agreement, discussing all conditions of interruptible service, will be signed by Trico and the Customer.

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the Customer

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in the Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

Service Availability Charge

A Service Availability Charge to be paid by the Customer to the Cooperative may be included in the contract to reimburse the Cooperative for its operating expenses with regard to idle or standby services in connection with the facilities constructed or installed pursuant to the contract based upon the Cooperative's estimate of its actual operating costs for such idle or standby services.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

OPTIONAL ELECTRIC SERVICE FOR QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES 100 KW AND GREATER
SCHEDULE COGEN1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Optional Electric Service for Qualified Cogeneration and Small Power Production Facilities 100 kW and Greater Rate (COGEN1) is applicable to Customers of the Cooperative that own and operate qualified cogeneration and small power production facilities of 100 kW or more that meet qualifying status as defined under 18 CFR, Chapter 1, Part 292, Subpart B of the Federal Energy Regulatory Commission's regulations and pursuant to the Arizona Corporation Commission's Decision No. 52345. The facility's generator(s) and Customer's load must be located at the same premise.

The owner of the Qualifying Facility (QF) shall enter into a contract pertaining to the operation of the QF by the QF owner with the Cooperative, the Cooperative's power supplier, Arizona Electric Power Cooperative, Inc. (AEPCO), and the Cooperative's transmission provider, Southwest Transmission Cooperative, Inc. (SWTC), to implement this schedule COGEN1 consistent with the terms and conditions set forth herein.

Type of Service

Single- or three-phase, alternating current, 60 cycles, at available secondary or primary voltages at one standard voltage as may be selected by the Customer.

Supplementary Power

A. Definition of Supplementary Power
Supplementary power is the kW capacity and related kWh energy purchased by the QF in excess of the production capability of the QF's generating equipment.

B. Rates
The rates charged for supplementary power shall be the appropriate standard offer retail Tariff of the Cooperative which is applicable to the QF's class of service or any new retail rate agreed to by the parties and approved by the Arizona Corporation Commission.

C. Determination of Supplementary Energy
Supplementary energy shall be equal to the metered kWh being supplied to the QF, less any kWh billed as standby or maintenance energy.

D. Determination of Supplemental Demand
Supplemental demand shall be the greater of:

1. The metered demand, measured in accordance with the Cooperative's appropriate standard offer retail rate schedule, less any standby and maintenance demand; or
2. The minimum supplemental billing demand specified in the QF's contract.

Standby and Maintenance Power

A. Definition of Standby - Maintenance Power
Standby and maintenance power is the kW capacity and related kWh supplied by the Cooperative attributable to forced or scheduled outages by the QF, respectively.

B. Rates
Reservation/Capacity Charge
The reservation/capacity charge for standby and maintenance power shall be the sum of the distribution billing demand charge in the applicable direct access retail rate schedule plus the applicable demand charges in AEPCO's Tariff and SWTC's Tariff each month multiplied by the contract Standby Capacity, as determined in Section E. of this section.

Energy Charge
The rate applicable to standby and maintenance energy shall be the sum of the distribution energy charge in the applicable direct access retail rate schedule plus the current energy rate from AEPCO multiplied by the sum of the Standby Energy and Maintenance Energy as determined in Sections C and D of this section.

C. Determination of Standby Energy
Standby energy is defined as electric energy supplied by the Cooperative to replace power ordinarily generated by the Customer's generation facility during unscheduled full and partial outages of said facility. Standby energy is equal to the difference between the maximum energy output of the Customer's generator(s) and the energy measured on the Customer's generator meter(s) for the billing period, except those periods where energy supplied by the Cooperative is zero.

D. Determination of Maintenance Energy
Maintenance energy is defined as energy supplied to the Customer to a maximum of the Contract Standby Capacity times the hours in the Scheduled Maintenance period. Maintenance periods shall not exceed 30 days and must be scheduled during off peak months. Customer shall supply the Cooperative with a maintenance Schedule for a 12-month period at least 60 days prior to the beginning of that period, which is subject to the Cooperative's approval. Energy used in excess of a 30-day period of unauthorized maintenance energy shall be billed on the Supplemental Power Rate as specified in this Schedule.

E. Contract Standby Capacity kW
Contract Standby Capacity kilowatt (kW) amount is the amount of cogeneration or self-generation capacity for which the Customer contracts with the Cooperative for Standby

Service. If the contract Standby Capacity is exceeded and not covered by the Supplementary Power provisions of this tariff, then the contract standby capacity is automatically increased to the new level. The Contract Standby Capacity kW cannot exceed the maximum net output rating(s) of the connected generator(s).

Basic Service Charge

The monthly basic service charge shall be the service charge contained in the Cooperative's current applicable retail rate schedule.

Conditions of Service

Scheduled outages for maintenance by the QF shall be submitted each December to AEPCO for the next coming year for its approval. Scheduled outages will not be permitted during the months of April through October.

Interconnection Charge

The QF shall pay all costs associated with any and all additions, modifications or alterations to SWTC's or Trico Electric Cooperative's electric system necessitated or incurred in the establishment and operation of the interconnection with the QF, including but not limited to any and all modifications required for the metering of power and energy or for the efficient, safe and reliable operation of the QF's facilities with SWTC's electric system or the Cooperative's electric system.

Facility Charge on Dedicated Facilities

The QF shall be required to pay to the Cooperative a monthly facilities charge to recover all related costs of any dedicated facilities constructed to serve the QF on a firm power and energy basis.

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

Contract Period

As provided in the Cooperative's agreement for service with the Customer.

OPTIONAL ELECTRIC SERVICE FOR QUALIFIED COGENERATION AND SMALL POWER PRODUCTION FACILITIES 100 KW AND GREATER SCHEDULE COGEN1

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

Demand Side Management (DSM) Programs; DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

COGENERATION QUALIFYING FACILITIES SERVICE
SCHEDULE QF1

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The Cogeneration Qualifying Facilities Rate (QF1) is applicable to owners of co-generation qualifying facilities and small power production facilities under 100 kW who are retail Customers and who enter into a written contract with the Cooperative with respect to such service. Service shall be supplied at one point of delivery where part or all of the electrical requirements of the Customer can be supplied from a source or sources, owned by the Customer, and where such sources are connected for parallel operation of the Customer's system with the system of the Cooperative. Customer sources may include but are not limited to windmills, water wheels, solar conversion and geothermal devices, each of which is capable of generating less than 100 kW.

Type of Service

The type of service furnished the Customer pursuant to this rate tariff shall be determined in the reasonable discretion of the Cooperative.

Monthly Rate

All purchases from the Cooperative and sales to the Cooperative shall be treated separately. For capacity and energy supplied by the Cooperative to the Customer, the applicable rate shall apply. For energy supplied by the Customer to the Cooperative, the rates shall be as follows:

For non-firm power the purchase rate will be the sum of the wholesale energy and fuel charges from the Cooperative's wholesale power supplier. For firm service the purchase rate will be the non-firm purchase rate plus ten percent (10%).

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes of governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Rules, Regulations and Line Extension Policy (RRLEP)

The RRLEP of the Cooperative as on file with the Arizona Corporation Commission shall apply to this rate schedule.

COGENERATION QUALIFYING FACILITIES SERVICE
SCHEDULE QF1

Upon application for service or upon request, the Cooperative will assist the Customer in selecting the rate schedule best suited to his requirements, but the Cooperative does not guarantee the Customer will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions or use of service, the Cooperative will assist in determining if a change in rates is desirable. No more than one (1) such change at the Customer's request will be made within any twelve (12) month period.

Contract

If service is requested in the Cooperative's Certificated Area and the provisions outlined in the Availability Clause of this rate tariff cannot be met, it will be necessary for the Cooperative and Customer to mutually agree, in a written contract, on the conditions under which service will be made available.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

STANDARD OFFER TARIFF

SCHEDULE OF SPECIAL CHARGES
SCHEDULE SC

SERVICE ESTABLISHMENT FEE:

For the establishment of service to a single existing connection:	**$ 50.00**
For the establishment of service to a single new construction service connection:	**$ 100.00**

A Service Establishment Fee shall entitle the Customer to one service connection including transfer of service. The Service Establishment Fee shall be non-refundable, non-transferable and shall not apply against a final or other bill rendered by the Cooperative to the Customer. An additional Service Establishment Fee shall be collected for each additional service connection, or transfer of service.

RE-ESTABLISHMENT FEE DURING REGULAR HOURS:	**$ 50.00**
RE-ESTABLISHMENT FEE AFTER REGULAR HOURS:	**$ 70.00**

A fee will be charged to re-establish electric service when it is reconnected to the same Customer who requested the service to be disconnected. If the disconnection period is 12 months or less, the applicable monthly Customer Charge for each month of the disconnection period shall also be paid by the Customer. Should the Customer request the re-establishment after regular hours, the after hours fee will be charged.

SERVICE CALLS AND SERVICE CONNECTION FEES:	**$ 50.00**
RETURN TRIP:	**$ 50.00**

The fees for Service Calls, Return Trip and Service Connections during regular hours shall be charged in accordance with Section 144 of the Rules, as defined below. Reasonable efforts will be made to advise the Customer about appropriate service call fees before the service call begins. Fees shall be applicable for each trip made.

A. For interruptions caused by the Customer's willful act or omission, negligence or failure of Customer-owned equipment, even though the Cooperative is unable to work beyond the point of delivery.

B. For reconnection of electric service to any Customer previously disconnected for non-payment, unlawful use of service, misrepresentation to the Cooperative, unsafe conditions, threats to Cooperative personnel or property, failure to permit access, detrimental effects of Customer loads on the Cooperative System, failure to establish credit and/or sign an agreement for service, or any other reason authorizing the Cooperative to make such disconnections; per trip.

SCHEDULE OF SPECIAL CHARGES
SCHEDULE SC

C. For response to a power interruption call where it is determined that the Customer's equipment is at fault and there is electricity at the point of delivery.

D. To a Customer who fails to comply with any of the Cooperative's Conditions for Supplying Service requirements listed under Section 106 or any other applicable section, or fails to meet any of the Customer's Responsibility. Including return trips for Cooperative inspection of distributed generation.

SERVICE CALLS AFTER REGULAR HOURS:

For calls requiring a meter crew:	**$ 70.00**
For calls requiring a service crew:	**$ 175.00**

The fees for Service Calls after Regular Hours shall be charged in accordance with Section 144 of the Rules, as defined below. The amount of the Service Fees shall be determined by the type of personnel needed. Reasonable efforts will be made to advise the Customer about appropriate service call fees before the service call begins. Fees shall be applicable for each trip made.

A. For interruptions caused by the Customer's willful act or omission, negligence or failure of Customer-owned equipment, even though the Cooperative is unable to perform any work beyond the point of delivery.

B. For reconnection of electric service to any Customer previously disconnected for non-payment, unlawful use of service, misrepresentation to the Cooperative, unsafe conditions, threats to Cooperative personnel or property, failure to permit access, detrimental effects of Customer loads on the Cooperative system, failure to establish credit and/or sign an agreement for service or any other reason authorizing the Cooperative or any other such disconnection. Such work will be performed only when requested and agreed to by the Customer.

C. For response to a power interruption call where it is determined that the Customer's equipment is at fault and there is electricity at the point of delivery.

D. To a Customer who fails to comply with any of the Cooperative's Conditions for Supplying Service requirements listed under Section 106 or any other applicable section of the Rules, or fails to meet any of the Customer's Responsibility in Steps.

METER RE-READS: **$ 25.00**

The fees for Meter Re-reads shall be charged in accordance with Section 315 of the Rules which has been amended to read as follows. The Cooperative will reread a meter at the request of the Customer for a fee, provided that the original reading was not in error. When a reading is found to be in error, the re-read shall be at no charge to the Customer.

SCHEDULE OF SPECIAL CHARGES
SCHEDULE SC

CUSTOMER-REQUESTED METER TESTS: **$ 35.00**

The fees for Customer-Requested Meter Tests shall be charged in accordance with Section 331 of the Rules. However, if the meter is found to be in error by more than three percent (3%), no meter testing fee will be charge to the Customer.

SERVICE CHARGE FOR INSUFFICIENT FUNDS CHECK, PAYMENT TRANSACTION RETURN OR CHARGE BACK: **$ 30.00**

The fees for insufficient funds check, payment transaction returns, or charge backs shall be charged in accordance with Section 337 of the Rules.

LATE PAYMENT CHARGE: **1% of Unpaid Balance**

A one percent (1%) late payment charge on the unpaid balance will be applied after 30 days, from the date the bill is rendered, as defined in Section 321 of the Rules.

COLLECTION FEE: **$ 50.00**

This fee will be applied each time a Cooperative authorized representative must make a field contact regarding a delinquent bill, picks up a payment at the request of the Customer, or must return to the same premises when the Customer fails to have funds available for a service reconnect, previously disconnected for non-payment, as defined in Section 144 of the Rules.

SERVICE AVAILABILITY CHARGE:

A Service Availability Charge may be charged to reimburse the Cooperative for its operating expenses with regard to idle or standby services. The Service Availability charge may be based on the monthly Customer charge or minimum, per Section 372 of the Rules, or be based upon the Cooperative's estimate of its actual operating costs for such idle or standby services, whichever the Cooperative determines appropriate.

INTEREST ON DEPOSITS:

The Cooperative will pay an interest rate on deposits, as referred to in Section 126 of the Rules, equal to the Annual Three Month Commercial Financial Paper (TMCFP) rate as published by the Federal Reserve. This floating interest rate is applicable to Customer security deposits held by the Cooperative for new Customers or Customers who have not paid their bills in a timely fashion. The Cooperative will update the TMCFP rate annually, in January of each year.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: September 1, 2013

STANDARD OFFER TARIFF

DEMAND SIDE MANAGEMENT ADJUSTMENT
SCHEDULE DSMA

Background
On August 10, 2010, the Arizona Corporation Commission ("Commission") issued Decision No. 71819 that contained an Electric Energy Efficiency Standard ("EEES") which set forth annual energy efficiency requirements for all affected electric utilities in the State of Arizona as well as a requirement that each affected electric utility file with the Commission for approval of a Demand Side Management ("DSM") Tariff to fund such energy efficiency requirements.

Availability
In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served. The standard Rules, Regulations and Line Extension Policies of the Cooperative, as on file from time to time with the Arizona Corporation Commission, shall apply where not inconsistent with this tariff.

Application
The Cooperative shall recover its costs for Commission pre-approved DSM programs through a DSM mechanism which shall provide for a separate and specific Commission accounting for pre-approved DSM costs. The Demand Side Management Adjustment Tariff (DSMA) shall be applicable to all Customers receiving standard service and will be assessed monthly, per billing meter, on a per kilowatt-hour of the retail electricity purchased by the consumer.

Monthly Rate

The DSMA shall be applied to all monthly bills at $0.000058 per kilowatt-hour, per billing meter.

The DSMA is in addition to all other rates and charges applicable for service to the Customer.

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2015

STANDARD OFFER TARIFF

RENEWABLE ENERGY STANDARD TARIFF
SCHEDULE RES

Background
On November 14, 2006, the Arizona Corporation Commission ("Commission") issued Decision No. 69127 that contained a Renewable Energy Standard ("RES") which set forth annual renewable energy requirements for all affected electric utilities in the State of Arizona as well as a requirement that each affected electric utility file with the Commission for approval a RES Tariff to fund such renewable energy requirements.

Availability
In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application
On all bills for all governmental and agricultural Customers/Customers, a Renewable Energy Standard Surcharge mandated by the Arizona Corporation Commission ("Commission") will be assessed monthly, per billing meter, at the lesser of the per kilowatt-hour of retail electricity purchased by the consumer, or the maximum, both as stated below. In the case of unmetered services, Trico Electric Cooperative, Inc. ("Cooperative") shall, for purposes of billing the RES Surcharge and subject to the maximum assessment set forth herein, use the lesser of (i) the load profile or otherwise estimated kWh required to provide the service in question; or (ii) the service's contract kWh.

Monthly Rate

Customer	kWh	Maximum
Governmental and Agricultural	$0.00	$0.00

RENEWABLE ENERGY STANDARD TARIFF
SCHEDULE RES

Application
On all bills in all other tariff service categories than those listed above, an RES Surcharge mandated by the Commission will be assessed monthly, per billing meter, at the lesser of the per kilowatt-hour of retail electricity purchased by the consumer, or the maximum stated below.

In the case of unmetered services, the Cooperative shall, for purposes of billing the RES Surcharge and subject to the maximum assessment set forth herein, use the lesser of (i) the load profile or otherwise estimated kWh required to provide the service in question; or (ii) the service's contract kWh.

Monthly Rate

Customer		kWh	Maximum
Residential		$0.00	$0.00
Non-Residential		$0.00	$0.00
Non-Residential whose metered demand is 3,000 kW or more for 3 consecutive months		$0.00	$0.00

The RES Surcharge is in addition to all other rates and charges applicable to service to the Customer/Customer.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2011

STANDARD OFFER TARIFF

RENEWABLE ENERGY CUSTOMER SELF-DIRECTED TARIFF
SCHEDULE RESD

Background
On November 14, 2006, the Arizona Corporation Commission ("Commission") issued Decision No. 69127 that contained a Renewable Energy Standard ("RES") that set forth annual renewable energy requirements for all affected electric utilities in the State of Arizona as well as a requirement that each affected electric utility file with the Commission for approval a RES Customer Self-Directed Option Tariff as defined below.

Availability
The RES Customer Self-Directed Option is available to single and three phase service for Non-Residential Customers with multiple meters that pay more than $25,000 annually in RES Surcharge funds pursuant to the Renewable Energy Standard Tariff for any number of related accounts or services within the Trico Electric Cooperative, Inc. ("Cooperative") service territory ("Eligible Customer").

Application
An Eligible Customer may apply to the Cooperative to receive funds to install Distributed Renewable Energy Resources. An Eligible Customer seeking to participate in this program shall submit to the Cooperative a completed application that describes the Renewable Energy Resources that it proposes to install and the projected cost of the project. An Eligible Customer shall provide at least half of the funding necessary to complete the project described in its application.

An Eligible Customer shall enter into a contract with the Cooperative that specifies, at a minimum the following information: the type of Distributed Generation ("DG") resource, its total estimated cost, kWh output, its completion date, the expected life of the DG system, a schedule of the Eligible Customer's expenditures and invoices for the DG system, Cooperative payments to an Eligible Customer for the DG system and the amount of a Security Bond or Letter of Credit necessary to ensure the future operation of the Eligible Customer's DG System, metering equipment, maintenance, insurance and related costs.

Before connection to the Cooperative's electrical system, an Eligible Customer's DG Resource shall meet all of the Cooperative's DG interconnection requirements and guidelines.

All Renewable Energy Credits derived from the project, including generation and extra credit multipliers, shall be applied to satisfy the Cooperative's Annual Renewable Energy Requirement.

The funds annually received by an Eligible Customer pursuant to this tariff may not exceed the amount annually paid by the Eligible Customer pursuant to the RES Surcharge Tariff.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2011

VOLUNTARY RENEWABLE ENERGY STANDARD PROGRAM TARIFF
SCHEDULE VRES

Availability
The Renewable Energy Standard ("RES") Voluntary Contribution Program is available to all Customers of Trico Electric Cooperative, Inc. ("Cooperative") who wish to contribute funds in support of the construction and acquisition of renewable resources.

Background
On November 14, 2006, the Arizona Corporation Commission ("Commission") issued Decision No. 69127 that contained a Renewable Energy Standard ("RES") that set forth annual renewable energy requirements for all affected electric utilities in the State of Arizona. The RES Plan may be modified from time to time on further application to the Commission. Funds to support the RES Plan are collected by the Cooperative pursuant to Commission Rules and applicable RES Surcharge tariffs and are remitted to Cooperative for expenditure in accordance with the terms of the approved RES Plan. The purpose of this RES Voluntary Contribution Program is to allow Customers an option to contribute additional amounts if they desire in support of the RES Plan.

Contribution Program
Participation in the Contribution Program is voluntary. Any Customer desiring to participate in the Contribution Program may do so by completing and returning to the Cooperative a form supplied by the Cooperative specifying the amount of the monthly contribution. Customers may purchase 50 kWh blocks of green energy for an additional cost of $2.00 per block. The amount of the cost of the blocks selected will then be added to the Customer's bill on a monthly basis. All monthly contributions associated with this tariff shall be utilized to permit the participation in the Contribution Program. Customers may cancel their participation in the Contribution Program at any time by notifying the Cooperative at least 30 days in advance of the Customer's billing date of their decision to cancel effective as to such billing date on a form supplied by the Cooperative.

Elections to participate or to cancel participation in the Contribution Program may only be by completion of applications on forms supplied by the Cooperative, which are available at the Cooperative's main office or on the Cooperative's website.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: January 1, 2011

SUNWATTS SUN FARM TARIFF
SCHEDULE RESF

Background and Availability

The Arizona Corporation Commission ("Commission") approved the Renewable Energy Standard and Tariff Rules ("REST Rules") in Decision No. 69127 dated November 14, 2006, which set out the renewable energy requirements for all affected electric utilities in the State of Arizona. Trico Electric Cooperative, Inc. ("Cooperative") has prepared a REST Plan which provides for rebate support of Customer owned renewable resources and larger scale renewable resources. The REST Plan may be modified from time to time on further application to the Commission.

The Residential Community Solar Demonstration Project Voluntary Purchase Program ("SunWatts Sun Farm") is part of the Cooperative REST Plan and is available to all RS1, RS1TOU, GS1, GS2 and GS3 Customers of the Cooperative who wish to participate in support of renewable resources through purchase of energy output from the installation of a Cooperative-owned Photovoltaic (PV) generation facility. A Customer may purchase panel output up to but not to exceed their average monthly kWh energy usage in the last twelve month period up to a maximum of 10,000 watts per Customer.

The Sun Watts Sun Farm is designed to produce 227,000 watts and is located at the Cooperative office facility at 8600 W. Tangerine Road, Marana, Arizona 85658. The Cooperative plans to utilize all proceeds associated with this tariff for future expansion of the SunWatts Sun Farm through construction of additional SunWatts Sun Farm renewable resources.

Program

The SunWatts Sun Farm provides for voluntary participation by residential and small commercial Customers which may benefit renters and other Customers who cannot install renewable resources on their property, to Customers that want to expend only a small amount of initial capital on renewable energy.

Any Customer desiring to participate in the SunWatts Sun Farm must complete and return an application. Participation shall be on a first-come, first-serve basis until the full output of the facility is assigned. Each applicant awarded panel output will enter into a purchase contract with the Cooperative, which will specify the rights and obligations of the arrangements for a twenty year term.

SUNWATTS SUN FARM TARIFF
SCHEDULE RESF

Customers may purchase the output of PV panels from the SunWatts Sun Farm in ¼, ½ and full panel increments. The Customer will be billed the full cost of the panels contracted as a one-time up-front charge.

The Customer will receive a credit for the energy output of the panel(s), estimated to be 432 kWh per year, per panel, in accordance with the rates and charges under the Customer's Standard Rate Schedule in a similar fashion as the Cooperative's Net Metering Tariff Schedule NM. The Cooperative will apply the credit to the Customer's monthly bill for the 20 year term of the purchase contract or until such time as the Customer's purchase contract is terminated or the Customer assigns some or all of the solar panels subject to a purchase contract subject to the Cooperative's written approval. The Cooperative shall retain the rights to all the Renewable Energy Credits (RECs) produced by the Sun Watts Sun Farm.

Pricing of the Sun Watts Sun Farm panels is described in the table below:

Panel Size	Cost
Quarter Panel	$230
One Half Panel	$460
Full Panel	$920

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

NET METERING TARIFF
SCHEDULE NM (FROZEN)

Availability

Net Metering service is available to all Customers of Trico Electric Cooperative, Inc. (Cooperative) with a qualifying Net Metering Facility. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades. The electric energy generated by or on behalf of the Customer from a qualifying Net Metering Facility and delivered to the Cooperative's distribution facilities may be used to offset electric energy provided by the Cooperative during the applicable billing period. The Net Metering Tariff (NM) is applicable to Customers prior to March 1, 2015. No new Customers will be accepted on this tariff after February 28, 2015.

Net Metering Facility means a facility for the production of electricity that:

a. Is operated by or on behalf of the Customer and is located on the Customer's premises;
b. Is intended primarily to provide part or all of the Customer's requirements for electricity;
c. Uses Renewable Resources, a Fuel Cell or CHP (as defined below);
d. Has a generating capacity less than or equal to 125% of the Customer's total connected load, or in the absence of Customer load data, capacity less than or equal to the Customer's electric service drop capacity; and
e. Is interconnected with and can operate in parallel and in phase with the Cooperative's existing distribution system.

Service under this tariff is available provided the rated capacity of the Customer's Net Metering Facility does not exceed the Cooperative's service capacity. The Customer shall comply with all of the Cooperative's interconnection standards. The Customer is also required to sign and complete a net metering application prior to being provided Net Metering Service.

Metering

Metering installed for the service provided under this tariff shall be capable of registering and accumulating the kilowatt-hours (kWh) of electricity flowing in both directions in a billing period.

NET METERING TARIFF
SCHEDULE NM (FROZEN)

Monthly Billing

If the kWh energy supplied by the Cooperative exceeds the kWh energy that is generated by the Customer's Net Metering Facility and delivered back to the Cooperative during the billing period, the Customer shall be billed for the net kWh energy supplied by the Cooperative in accordance with the rates and charges under the Customer's Standard Rate Schedule.

If the kWh energy generated by the Customer's Net Metering Facility and delivered back to the Cooperative exceeds the kWh energy supplied by the Cooperative in the billing period, the Customer shall be credited during subsequent billing periods for the excess kWh energy generated. The Cooperative shall apply the credit by using the excess kWh energy generated during the billing period to reduce the kWh energy supplied (not kW or kVA demand or Customer charges) and billed by the Cooperative during the subsequent billing periods.

Customers taking service under time-of-use rates who are to receive credit in a subsequent billing period for excess kWh energy generated shall receive such credit during the following billing periods during the on- or off- peak periods corresponding to the on- or off- peak periods in which the kWh energy were generated by the Customer.

Each Calendar Year, for the Customer bills produced in October (September usage) or in the last billing period that the Customer discontinues service under this tariff, the Cooperative shall issue a check or billing credit to Customers with Net Metering Facilities for the balance of any credit due in excess of amounts owed by the Customer to the Cooperative for Non-Firm Power. The payment for any remaining credits shall be at the Cooperative's Annual Average Avoided Cost. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh. Any payment for Firm Power will be pursuant to a separate contract.

Administrative Charge

In order to determine accurate billing and usage, net metering Customers will need to have interval meter data available (minimum data collection of every half hour). This information is needed to ensure accurate billing and to calculate the net kWh energy billed or credited to the Customer's account. The following table shows the incremental costs for the increased data collection applicable to all rate classes.

Administrative Charge		**Monthly Rate**
Monthly Data Cost		$3.38

NET METERING TARIFF
SCHEDULE NM (FROZEN)

Definitions

1. Annual Average Avoided Cost: Defined as the average annual wholesale fuel and energy costs per kWh energy purchased from the Cooperative's wholesale power supplier during the calendar year. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh.

2. Calendar Year: The Calendar Year is defined as October 1 through September 30, for the purpose of determining the billing credit for the balance of any credit due in excess of amounts owed by the Customer to the Cooperative.

3. Renewable Resource: Means natural resources that can be replenished by natural processes, including biomass, biogas, geothermal, hydroelectric, solar or wind.

4. Combined Heat and Power or CHP: Means a system that generates electricity and useful thermal energy in a single, integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility (also known as cogeneration).

5. Fuel Cell: Means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be from Renewable Resources.

6. Non-Firm Power: Electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided, and the power can be interrupted by the Customer at any time.
7. Firm Power: Electric power available from the Customer's facilities, upon demand, at all times with an expected or demonstrated reliability that is covered by a separate multiparty purchase agreement among the Customer, and the Cooperative.

8. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. On-peak and off-peak time periods will be determined by the applicable Standard Rate Schedule.

9. Standard Rate Schedule: Any of the Cooperative's retail rate schedules with metered kWh charges.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ________________

ESTIMATION METHODOLOGIES
SCHEDULE EM

Application

The Estimation Methodologies Rate (EM) is applicable for purposes of bill estimation for all tariffs in the event a valid meter reading cannot be acquired. The Cooperative will make every reasonable attempt to secure an accurate reading of the meter. The Cooperative will make special efforts to secure an accurate reading of the meters for accounts with demand reading.

This rate is not applicable to resale or standby services.

Conditions for Estimated Bills

Estimated bills will be issued only under the following conditions:

A. Labor shortages or work stoppages beyond the control of the Cooperative.

B. Severe weather conditions, emergencies or other causes beyond the Cooperative's control which prevent the Cooperative from reading the meter.

C. Circumstances that make it dangerous or impossible to read the meter, including but not limited to: locked gates, blocked access to meters, threatening or abusive conduct of Customers, vicious or dangerous animals or missing meters.

D. Failure of a Customer who reads his own meter to deliver his meter reading to the Cooperative in accordance with the requirements of the Cooperative billing cycle. E. To facilitate timely billing for Customers using load profiles.

Notice of Estimation

Each bill based on estimated usage will indicate that it is an estimated bill and note the reason for estimation.

Estimation Procedures

Trico currently utilizes a Customer information system (CIS) for billing, bill calculations and bill estimations.

A. Detailed descriptions of estimation procedures for each of the conditions are numbered 1-12 below include but are not limited to:

ESTIMATION METHODOLOGIES
SCHEDULE EM

	Conditions for Estimated Bills	Estimation Procedures
1.	A kWh estimate with at least one year of history for the same Customer at same premise or new Customer with at least one year of premise history.	The CIS system calculates the estimate using the kWh, same month one year prior, from the same premise.
2.	A kWh estimate with less than 12 months' history for the same Customer at same premise.	The CIS system calculates the estimate using the kWh of the preceding month from the same premise.
3.	A kWh estimate with less than 12 months' history for a new Customer but with history on the premise.	The CIS system calculates the estimate using the kWh of the preceding month from the same premise.
4.	A kWh estimate with no prior consumption history.	The CIS system will bill the fixed monthly Customer charge only. The kWh will be billed with the next valid read in accordance with the Arizona Administrative Code.
5.	A kW estimate with a least one year of history for the same Customer at same premise or new Customer with one year of premise history.	The CIS system calculates the estimate using the kW, same month one year prior, from the same premise.
6.	A kW estimate with less than 12 months' history for the same Customer at same premise.	The CIS system calculates the estimate using the kW of the preceding month from the same premise.
7.	A kW estimate with less than 12 months' history for a new Customer but with history on the premise.	The CIS system calculates the estimate using the kW of the preceding month from the same premise.
8.	A kW estimate with no prior consumption history.	The CIS system does not estimate, a service order is issued for a meter technician to obtain a valid read.
9.	Time-of Use estimate with at least one year of history for the same Customer at same premise or new Customer with at least one year of premise history.	Time-of-Use has two readings, "on-peak" and "off-peak". The CIS system calculates the estimate using the "on-peak" and "off-peak" kWh reads, same month one year prior from the same premise.
10.	Time-of-Use estimate with less than 12 months' history for the same Customer at same premise.	Time-of-Use has two readings, "on-peak" and "off-peak". The CIS system calculates the estimate using the "on peak" and "off-peak" kWh of the preceding month from the same premise.
11.	Time-of-Use estimate with less than 12 months' history for a new Customer but with history on the premise.	Time-of-Use has two readings, "on-peak" and "off-peak". The CIS system calculates the estimate using the "on peak" and "off-peak" kWh of the preceding month from the same premise.
12.	Time-of-Use estimate with no prior consumption history for a new Customer at new premise.	The CIS system will bill the fixed monthly Customer charge only. The kWh will be billed with the next valid read in accordance with the Arizona Administrative Code.

ESTIMATION METHODOLOGIES
SCHEDULE EM

B. Variance in estimation methods for differing conditions.

Examples of differing causes for estimation include, but are not limited to: tampering, energy diversion, damaged or destroyed meter, partial meter failure, and meter reading equipment failure.

In the event the meter has been tampered with or destroyed, or energy diversion has occurred, the methods referred to in item A. above still apply, prorating the usage if the estimation period is less than a full billing cycle. Examples;

Tampering and/or Energy Diversion:

A valid read was obtained on October 1, Year Two. A tampering or energy diversion is discovered on October 15th, the meter has the same reading from October 1, Year Two. An investigation reveals the service is active and electricity is being consumed. The same service history indicated a kWh usage of 900 kWh for the month of October Year One. A manual estimate will prorate based upon a daily average of the 900 kWh divided by the number of days in the history record the same month (31) for a total of 29 kWh per day times the number of days tampered (15) for a final estimate of 435 kWh.

If the service does not have a 12 month history the same formula is used with the past 3 month average.

In the event the investigation reveals evidence that the tampering or energy diversion occurred for a period exceeding one month, the Cooperative will use the applicable estimation procedure to the point in time that the tampering or energy diversion may be definitely fixed, or 12 months.

Meter Damaged/Destroyed:

The same estimation procedure as described in item A. above is used if it is determined that the damage or destruction is caused by the Customer to the point in time that the damage or destruction may be definitely fixed or 12 months.

In the event the damage or destruction is otherwise caused, the estimation procedure is the same as described in item A. above, but the Customer responsibility is limited to 3 months for residential Customers and 6 months for non-residential Customers.

Partial Meter Failure:

If a meter is found to be deficient in recording any portion of the actual usage, the kW and kWh are estimated based on the percentage of deficiency for a period limited to 3 months for residential Customers and 6 months for non-residential Customers.

ESTIMATION METHODOLOGIES
SCHEDULE EM

C. Conditions when estimations are calculated by the CIS system.

The CIS system calculates the estimate when the meter of a service does not record a valid read for the normal billing cycle for any of the reasons listed under "Conditions for Estimated Bills" above.

D. Conditions when estimations are made manually

The manual estimate is made when there is a partial meter failure, or there is tampering, or a damaged/destroyed meter for less than the normal billing cycle and the bill must be prorated.

E. Procedures to minimize the need for using estimated data.

If feasible, the meter reader is asked to return to the service for a valid read. If the service has access problems an Offsite Meter Reading (OMR) or Automated Meter Reading (AMR) device may be installed. However, the Cooperative shall have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with property used in furnishing service and the exercise to any and all rights secured to it by law or the Arizona Corporation Commission.

F. Procedures for estimating first and final bills.

First and final bills are not estimated unless the meter fails. If the reading is not recorded for the first bill, the first bill is issued for the fixed monthly charge only. The total kWh will be billed on the first valid read. The final bill is not issued until such time a valid read is secured.

In the event of metering equipment that is damaged, destroyed or absent for the first or final bill, the estimate is the same as B. and D. above.

In the event of metering equipment failure for the first or final bill, the estimate is the same as B. and D. above.

In the event of metering equipment failure, is damaged, destroyed or absent for an account with a demand reading, for the first or final bill, the kWh and/or kW estimate is based on the connected equipment operating characteristics.

G. Procedure for estimation using Customer specific data.

If there is no service history available on which to base an estimate, the kWh and/or kW estimate is based on the connected equipment operating characteristics.

ESTIMATION METHODOLOGIES
SCHEDULE EM

H. Prepaid Electric Service Estimation Methodology.

If there are communication issues that prevent the Cooperative from obtaining a valid daily kWh reading, the kWh consumption will continue to accumulate in the meter. When a valid daily reading results in a negative account balance, the Customer will be notified that they have 2 business days to replenish the account to avoid disconnection for a negative balance. The web portal will indicate no usage for the days with missing kWh readings. The Cooperative will provide all notices in this order: 1) home phone, 2) voicemail, 3) written letter, or 4) e-mail (if available).

If after 7 days of no valid kWh readings, the Cooperative will physically check and/or replace the meter, the Customer will be notified and one of the following actions will be applied to determine or estimate the kWh consumption:

1. If a valid reading can be obtained from the meter and the reading results in a negative account balance, the Customer will have a minimum of 5 business days to bring the account into a positive balance to avoid disconnection for a negative account balance.
2. If the Cooperative cannot obtain a valid reading from the meter, Trico will use the last valid 5 day average kWh consumption, to determine the amount of kWh to be applied to the account. If this calculated billing results in the account having a negative account balance the Customer will have a minimum of 5 business days to bring the account into a positive balance to avoid disconnection for a negative account balance.
3. If the Customer does not have any prior consumption history, Trico will bill the daily fixed charges, plus applicable taxes only. If this billing results in the account having a negative account balance, the Customer will have a minimum of 5 business days to bring the account into a positive balance to avoid disconnection.

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: May 19, 2015

EXPERIMENTAL TARIFF

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

Availability

Available, on a voluntary basis, to Customers in the territory served by the Cooperative for Residential Use throughout the Cooperative's Service Area where the facilities of the Cooperative are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served, subject to the Cooperative's Service Conditions.

Participation allowed under this Tariff shall be determined by the Cooperative. Customers specified under Arizona Administrative Code R14-2-211.A.5 shall not be eligible for Schedule RPS. These ineligible Customers include, but are not limited to, those where termination of service would be especially dangerous to the health of the Customer, as determined by a licensed medical physician; those Customers where life supporting equipment used in the home is dependent on utility service; and those Customers where weather would be especially dangerous to health.

Application

Applicable, by request of the Customer only, to a Customer otherwise served under the Cooperative's Residential Service, Rate Schedule RS1 for all Single Family Dwellings when all service is supplied at one Point of Delivery through a single Service Line and Energy is metered through one Meter.

Not applicable to resale or standby or Customers that are served on any other rate schedule or Customers on the Cooperative's Levelized Billing Plan, deferred payment plan or installment plan.

Type of Service

The Type of service available under this schedule will be determined by the Cooperative and will only include 120/240 volt single phase residential accounts.

Monthly Rate

STANDARD RATE RESIDENTIAL PREPAID SERVICE	Power Supply		Metering	Meter Reading	Billing	Access	Total	Total Rate
Customer Charge ($/Customer/Day)			$0.1821	$0.0322	$0.2081	$0.2351	$0.6575	$0.6575
Energy Charge ($/kWh)								
First 800 kWh/mo	$0.0770							$0.1176
Over 800 kWh/mo	$0.0870					$0.0406	$0.0406	$0.1276

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

Tax Adjustment

To the charge computed in this rate schedule, including all adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Cooperative and/or the price or revenue from the electric energy or service sold and/or the volume of energy purchased for sale and/or sold hereunder.

Wholesale Power Cost Adjustment

The Cooperative shall, if purchased power cost is increased or decreased above or below the base purchased power cost of $0.081711 per kWh sold, flow through such increases or decreases to all classes of Customers.

In addition to the foregoing, all kWh sold to each Customer under this rate schedule shall be subject to an additional temporary wholesale power cost adjustment, if any, that may be charged the Cooperative by its supplier of electricity which consists of an additional surcharge, a temporary credit and/or a fuel bank surcharge.

Renewable Energy Standard (RES) Surcharge

The Cooperative shall add to its bill a RES Surcharge in accordance with the approved RES tariff to help offset the costs associated with the Cooperative's programs designed to promote alternative generation requirements that satisfy the RES as approved by the Arizona Corporation Commission. Other charges may be applicable subject to approval by the Arizona Corporation Commission.

The RPS tariff is subject to the REST Surcharge on a per kWh basis as all other Trico rates, but with the use of a daily (rather than monthly) REST Surcharge Cap. The methodology for calculating a daily REST surcharge Cap is based on the following formula; the Monthly Residential Rest Surcharge maximum × 12 months ÷ 365 days rounded to nearest mill (1/10 of a penny).

Demand Side Management Programs - DSM Adjustment Mechanism

The Cooperative shall recover its cost for pre-approved DSM programs through a separate DSM adjustment mechanism which shall provide for a separate and specific accounting for pre-approved DSM costs.

Rules and Regulations

The Rules and Regulations and Line Extension Policies of the Cooperative ("Rules") as on file with the Commission shall apply to this rate schedule.

The following Service Conditions of the Cooperative (based on A.A.C. R14-2 -201 to 213)), on file with the Commission, shall NOT apply to the following: Rules 125 through 131; Rules 301 through 303; Rules 307, 318; Rules 320 through 322; Rule 324; Rules 342 through 351; and Rule 358.

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

Experimental Service Conditions Applicable to Prepaid Metering Service Only

A. Availability:
The Prepaid Electric Service is available only to new or existing residential Customers with the following exceptions:
1. Residential critical load Customers are excluded from the prepaid electric service program.
2. Customers identified under ACC R14-2-211A.5 and those Customers under appropriate circumstances but beyond the scope of ACC R14-211.A.5 are not eligible for this rate.
3. Invoice groups which include loans or special billing.
4. Customer must have a valid email account and phone capable of receiving the messages and low balance alerts.

B. Enrollment:
The Customer must make a request and complete a Prepaid Electric Service Application.
1. In addition to the information provided in Rule 101, the prepaid applicant is encouraged to provide the following:
   a. Secondary email address
   b. Cell phone number with text capability and/or second phone number
   c. Other approved method of communication other than US Postal Mail.
2. The Cooperative will allow enrollment into prepaid service if the Customer meets the eligibility requirements, including:
   a. The Customer must pay all applicable fees prior to commencement of service.
   b. A $50.00 credit balance has been established to activate the account.

C. Billing, Payments and Infomation:
Paper statements will not be provided under the prepaid program. Billing information, as well as payment and account information can be obtained at:
1. Trico business offices during normal business hours.
2. Integrated Voice Recognition (IVR) at 520-744-2944 or 1-866-999-8441.
3. Online at www.trico.coop 24 hours a day.

D. Estimating Prepaid Balances and Customer Notices:
1. Trico can provide an estimate based upon the most current use history of the Customer, of the suggested amount to be initially deposited with Trico and the estimated days that such prepayment should provide paid electric service for the Customer.
2. As energy is consumed, the credit balance is reduced until either the balance is exhausted or additional payments are added to the balance. Balances can be checked online at www.trico.coop any time. Upon request, Customers can be notified of their estimated balance by email, and/or other electronic means if Customer provides the necessary contact information.
   a. The notice will be generated daily when the Customer's credit balance is less than their current daily average usage times four (4). The daily average usage will be calculated using up to the previous thirty (30) days of consumption history.
   b. These estimates are based on the historic information available but can be affected by changes in the Customer's usage or needs. The Customer is responsible for ensuring that a credit balance is maintained on the account.

E. Transfers and optional Debt Recovery for Outstanding Balances
1. Accounts that are on existing post-paid electric service may be converted to prepaid electric service.

RESIDENTIAL PREPAID SERVICE
SCHEDULE RPS

2. When existing Customers that convert from post-paid residential service the existing deposit, if any, is applied toward any outstanding balance of the post-paid account with the remaining credit applied to prepaid service.
3. All post-paid fees and unbilled energy charges must be paid in full except for the provisions below:
   a. There is a debt recovery feature available within limits to recover amounts due from a prior post-paid account, when applying for prepaid service. A percentage (20% to 50%) of each prepaid electric service payment can be applied to an outstanding debt up to $400.00
   b. Outstanding amounts over $400.00 must be paid down to the $400.00 level prior to being eligible for the prepaid electric service program.
   c. The Customer agrees to make prepaid payments of sufficient amounts to pay down the outstanding amounts in no more than four (4) months.
   d. If the Customer fails to pay the outstanding balance within the four (4) months allowed, Trico has the right to disconnect the prepaid service until the outstanding balance is paid in full.
4. Trico will transfer the existing membership fee on the post-paid to the new account where the Customer will not be required to make an additional payment.
5. The Customer may elect to convert from prepaid electric service back to post-paid service. At which time, the Cooperative may require full payment of the deposit to continue service. Customers who cancel their prepaid accounts may not re-apply for a new Prepaid account at the same location for a six (6) month period.

F. Terminating and Restoring Prepaid Electric Service:

Prepaid meters are equipped to allow remote disconnection / reconnection of service.

1. Service terminated at the request of the Customer will receive a refund of any remaining credit on the account after all final bill amounts have been calculated.
2. Electric service may be subject to immediate disconnection any time the account does not have a credit balance.
3. Following a disconnect because the account does not have a credit balance, the Customer must pay any unpaid balance from the result of energy consumption from the time the account has reached a zero ($0.00) balance and when the Cooperative issued the disconnection command, plus purchase a minimum of $20.00 prepaid electric service, if applicable, before service is reconnected.
4. If an account is disconnected because the account does not have a credit balance and does not become current after ten (10) days, the account will be considered closed and the Cooperative will mail a final bill to the last known address of the Customer on file for all unpaid charges.
5. Service will not be disconnected where weather will be especially dangerous to health as defined in the Cooperative's Rules or as determined by the Commission.

Exhibit KC-2

"CLEAN"

ELECTRIC RATES

TRICO ELECTRIC COOPERATIVE, INC.
8600 W. Tangerine Road
Marana, Arizona 85653
Filed By: Vincent Nitido
Title: General Manager/CEO

Effective Date: ______________

STANDARD OFFER TARIFF

NET METERING TARIFF
SCHEDULE NM1

Availability

Net Metering service is available to all customers of Trico Electric Cooperative, Inc. (Cooperative) with a qualifying Net Metering Facility. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades. The electric energy generated by or on behalf of the customer from a qualifying Net Metering Facility and delivered to the Cooperative's distribution facilities may be used to offset electric energy provided by the Cooperative during the applicable billing period in accordance with the provisions of the Monthly Billing described herein.

Net Metering Facility means a facility for the production of electricity that:

a. Is operated by or on behalf of the customer and is located on the customer's premises;
b. Is intended primarily to provide part or all of the customer's requirements for electricity;
c. Uses Renewable Resources, a Fuel Cell or CHP (as defined below);
d. Has a generating capacity less than or equal to 125% of the customer's total connected load, or in the absence of customer load data, capacity less than or equal to the customer's electric service drop capacity; and
e. Is interconnected with and can operate in parallel and in phase with the Cooperative's existing distribution system.

Service under this tariff is available provided the rated capacity of the customer's Net Metering Facility does not exceed the Cooperative's service capacity. The customer shall comply with all of the Cooperative's interconnection standards. The customer is also required to sign and complete a net metering application prior to being provided Net Metering Service.

Metering

Metering installed for the service provided under this tariff shall be capable of registering and accumulating the kilowatt-hours (kWh) of electricity flowing in both directions in a billing period.

Monthly Billing

The energy (kWh) supplied by the Cooperative to the customer during the billing period, shall be billed by the Cooperative in accordance with the rates and charges under the customer's Standard Rate Schedule.

The energy (kWh) generated by the customer's Net Metering Facility and delivered back to the Cooperative shall be credited to the customer during the billing period at the Cooperative's Annual Average Avoided Cost. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh. Any payment for Firm Power will be pursuant to a separate contract.

Administrative Charge

In order to determine accurate billing and usage, net metering customers will need to have interval meter data available (minimum data collection of every half hour). This information is needed to ensure accurate billing and to calculate the net energy (kWh) billed or credited to the customer's account. The following table shows the incremental costs for the increased data collection applicable to all rate classes.

Administrative Charge		**Monthly Rate**
Monthly Data Cost		$3.38

NET METERING TARIFF
SCHEDULE NM1

Definitions

1. Annual Average Avoided Cost: Defined as the average annual wholesale fuel and energy costs per kWh energy purchased from the Cooperative's wholesale power supplier during the calendar year. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh.

2. Renewable Resource: Means natural resources that can be replenished by natural processes, including biomass, biogas, geothermal, hydroelectric, solar or wind.

3. Combined Heat and Power or CHP: Means a system that generates electricity and useful thermal energy in a single, integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility (also known as cogeneration).

4. Fuel Cell: Means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be from Renewable Resources.

5. Non-Firm Power: Electric power which is supplied by the customer's generator at the customer's option, where no firm guarantee is provided, and the power can be interrupted by the customer at any time.

6. Firm Power: Electric power available from the customer's facilities, upon demand, at all times with an expected or demonstrated reliability that is covered by a separate multiparty purchase agreement among the customer, the Cooperative, Arizona Electric Power Cooperative and Southwest Transmission Cooperative.

7. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. On-peak and off-peak time periods will be determined by the applicable Standard Rate Schedule.

8. Standard Rate Schedule: Any of the Cooperative's retail rate schedules with metered energy (kWh) charges.

“REDLINE”

ELECTRIC RATES

TRICO ELECTRIC COOPERATIVE, INC.
8600 W. Tangerine Road
Marana, Arizona 85653
Filed By: Vincent Nitido
Title: General Manager/CEO

Effective Date: ~~September 1, 2015~~______________

STANDARD OFFER TARIFF

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NET METERING TARIFF
SCHEDULE ~~NM~~NM1

Availability

Net Metering service is available to all customers of Trico Electric Cooperative, Inc. (Cooperative) with a qualifying Net Metering Facility. Participation under this schedule is subject to availability of enhanced metering and billing system upgrades. The electric energy generated by or on behalf of the customer from a qualifying Net Metering Facility and delivered to the Cooperative's distribution facilities may be used to offset electric energy provided by the Cooperative during the applicable billing period in accordance with the provisions of the Monthly Billing described herein.

Net Metering Facility means a facility for the production of electricity that:

a. Is operated by or on behalf of the customer and is located on the customer's premises;
b. Is intended primarily to provide part or all of the customer's requirements for electricity;
c. Uses Renewable Resources, a Fuel Cell or CHP (as defined below);
d. Has a generating capacity less than or equal to 125% of the customer's total connected load, or in the absence of customer load data, capacity less than or equal to the customer's electric service drop capacity; and
e. Is interconnected with and can operate in parallel and in phase with the Cooperative's existing distribution system.

Service under this tariff is available provided the rated capacity of the customer's Net Metering Facility does not exceed the Cooperative's service capacity. The customer shall comply with all of the Cooperative's interconnection standards. The customer is also required to sign and complete a net metering application prior to being provided Net Metering Service.

~~Net Metering Facilities with generation capacity that exceeds 1,000 kilowatts, which are interconnected presently, or desire to become interconnected, may, at Arizona Electric Power Cooperative's option, be subject to the negotiated terms and conditions set forth in multilateral contracts among the customer, Arizona Electric Power Cooperative, Southwest Transmission Cooperative and the Cooperative.~~

Metering

Metering installed for the service provided under this tariff shall be capable of registering and accumulating the kilowatt-hours (kWh) of electricity flowing in both directions in a billing period.

NET METERING TARIFF
SCHEDULE ~~NM~~NM1

Monthly Billing

~~If the kWh~~The energy (kWh) supplied by the Cooperative ~~exceeds the kWh energy that are generated by the customer's Net Metering Facility and delivered back~~ to the ~~Cooperative~~customer during the billing period, ~~the customer~~ shall be billed ~~for the net kWh energy supplied~~ by the Cooperative in accordance with the rates and charges under the customer's Standard Rate Schedule.

~~If the kWh~~The energy (kWh) generated by the customer's Net Metering Facility and delivered back to the Cooperative ~~exceeds the kWh energy supplied by the Cooperative in the billing period, the customer~~ shall be credited to the customer during ~~subsequent billing periods for the excess kWh energy generated. The Cooperative shall apply the credit by using the excess kWh energy generated during the billing period to reduce the kWh energy supplied (not kW or kVA demand or customer charges) and billed by the Cooperative during the subsequent billing periods.~~

~~Customers taking service under time-of-use rates who are to receive credit in a subsequent billing period for excess kWh energy generated shall receive such credit during the following billing periods during the on- or off- peak periods corresponding to the on- or off- peak periods in which the kWh energy were generated by the customer.~~

~~Each Calendar Year, for the customer bills produced in October (September usage) or in the last billing period that the customer discontinues service under this tariff, the Cooperative shall issue a check or billing credit to customers with Net Metering Facilities for the balance of any credit due in excess of amounts owed by the customer to the Cooperative for Non-Firm Power. The payment for any remaining credits shall be~~the billing period at the Cooperative's Annual Average Avoided Cost. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh. Any payment for Firm Power will be pursuant to a separate contract.

Administrative Charge

In order to determine accurate billing and usage, net metering customers will need to have interval meter data available (minimum data collection of every half hour). This information is needed to ensure accurate billing and to calculate the net ~~kWh~~ energy (kWh) billed or credited to the customer's account. The following table shows the incremental costs for the increased data collection applicable to all rate classes.

Administrative Charge	Monthly Rate
Monthly Data Cost	$3.38

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NET METERING TARIFF
SCHEDULE ~~NM~~NM1

Definitions

1. Annual Average Avoided Cost: Defined as the average annual wholesale fuel and energy costs per kWh energy purchased from the Cooperative's wholesale power supplier during the calendar year. The Cooperative's Annual Average Avoided Cost shall be set at $0.03662 per kWh.

~~2. Calendar Year: The Calendar Year is defined as October 1 through September 30, for the purpose of determining the billing credit for the balance of any credit due in excess of amounts owed by the customer to the Cooperative.~~

~~3.~~2. Renewable Resource: Means natural resources that can be replenished by natural processes, including biomass, biogas, geothermal, hydroelectric, solar or wind.

~~4.~~3. Combined Heat and Power or CHP: Means a system that generates electricity and useful thermal energy in a single, integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility (also known as cogeneration).

~~5.~~4. Fuel Cell: Means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be from Renewable Resources.

~~6.~~5. Non-Firm Power: Electric power which is supplied by the customer's generator at the customer's option, where no firm guarantee is provided, and the power can be interrupted by the customer at any time.

~~7.~~6. Firm Power: Electric power available from the customer's facilities, upon demand, at all times with an expected or demonstrated reliability that is covered by a separate multiparty purchase agreement among the customer, the Cooperative, Arizona Electric Power Cooperative and Southwest Transmission Cooperative.

~~8.~~7. Time Periods: Mountain Standard Time shall be used in the application of this rate schedule. On-peak and off-peak time periods will be determined by the applicable Standard Rate Schedule.

~~9.~~8. Standard Rate Schedule: Any of the Cooperative's retail rate schedules with metered energy (kWh) charges.

Exhibit KC-3

ELECTRIC RATES

Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: ______________

STANDARD OFFER TARIFF

SUNWATTS SUN FARM MONTHLY PARTICIPATION TARIFF
SCHEDULE RESFM

Background and Availability

The Arizona Corporation Commission ("Commission") approved the Renewable Energy Standard and Tariff Rules ("REST Rules") in Decision No. 69127 dated November 14, 2006, which set out the renewable energy requirements for all affected electric utilities in the State of Arizona. Trico Electric Cooperative, Inc. ("Cooperative") has prepared a REST Plan which provides for rebate support of customer owned renewable resources and larger scale renewable resources. The REST Plan may be modified from time to time on further application to the Commission.

The Residential Community Solar Demonstration Project Voluntary Purchase Program ("SunWatts Sun Farm") is part of the Cooperative REST Plan and is available to all RS1, GS1, GS2 and GS3 customers of the Cooperative who wish to participate in support of renewable resources through the purchase of energy output from the installation of a Cooperative-owned Photovoltaic (PV) generation facility. Customers being served under the Cooperative's time of use or self-generation tariffs may not purchase power under this Schedule RESFM (including, but not limited to the Cooperative's Net Metering Tariff Schedule NM).

Program

The Sun Watts Sun Farm is located at the Cooperative office facility at 8600 W. Tangerine Road, Marana, Arizona 85658. The SunWatts Sun Farm provides for voluntary participation by residential and small commercial customers which may benefit renters and other customers who cannot install renewable resources on their property, as well as, customers that want to expend minimal initial capital on renewable energy. The Cooperative plans to utilize all proceeds associated with this tariff for future expansion of the SunWatts Sun Farm through construction of additional SunWatts Sun Farm renewable resources.

A customer may purchase panel output up to but not to exceed their minimum monthly kWh energy usage in the last twelve month period. A Customer can purchase solar energy output in solar blocks of 432 kWh per year or 36 kWh per month. The Cooperative will apply the energy charge to the customer's monthly bill for a 20 year term or until such time as the customer cancels his/her participation in the program.

Rate

Wholesale power, transmission and distribution fixed costs will be applied to all energy delivered, including energy delivered under this Schedule RESFM. The customer is responsible for paying (each month) all charges incurred under their applicable rate schedule, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based or fixed charges under the Customer's current Rate will not be affected by elections under Schedule RESFM. No discounts specified in any of the above-listed standard offer tariffs will apply to this Rate. Table 1 below provides a summary of the proposed Cooperative Standard Offer Tariffs effective ______________ and Table 2 provides the resultant customer energy rate for each rate class with the RESSFM Tariff applied.

Table 1: Standard Offer Tariffs

Rate Class	Fixed Cost Portion Energy Rate ($/kWh)	Varriable Cost Portion Energy Rate ($/kWh)	Total Energy Rate ($/kWh)
RS1			
First 800 kWh/mo	$0.0868	$0.0308	$0.1176
Over 800 kWh/mo	$0.0968	$0.0308	$0.1276
GS1	$0.1029	$0.0308	$0.1337
GS2	$0.1156	$0.0308	$0.1464
GS3	$0.0441	$0.0308	$0.0749

Table 2: Schedule RESFM Applied to Standard Offer Tariffs

Rate Class	Fixed Cost Portion Energy Rate ($/kWh)	Varriable Cost Portion Energy Rate ($/kWh)	Total Energy Rate ($/kWh)
RS1			
First 800 kWh/mo	$0.0868	$0.06132	$0.1481
Over 800 kWh/mo	$0.0968	$0.06132	$0.1581
GS1	$0.1029	$0.06132	$0.1642
GS2	$0.1156	$0.06132	$0.1769
GS3	$0.0441	$0.06132	$0.1054

Terms and Conditions

1. Participation in this program is limited in the Cooperative's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis.

2. Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Schedule RESFM is prohibited. Should the Customer cancel service for any reason, his or her subscription under RESFM will expire.

3. Customers may add or delete solar blocks once within a twelve month period. Any addition of solar blocks will be at the then offered solar block energy rate.

4. Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular energy rate. Any electric

usage below the amount covered by the solar block(s) will not be rolled forward and credited again to the Customer's usage in the following month.

5. All contracted solar block energy and associated charges in a billing month will be excluded from the calculation of the Cooperative's Wholesale Power Cost Adjustor (PCA) and REST charges and/or credits.

6. The Cooperative shall retain the rights to all the Renewable Energy Credits (RECs) produced by the Sun Watts Sun Farm.

Exhibit KC-4

“CLEAN”

Rules,
Regulations
&
Line
Extension
Policies

Trico Electric Cooperative, Inc.
Rules, Regulations and Line Extension Policies
Effective Date: ________________

INDEX

PART 1. APPLICATION FOR ELECTRIC SERVICE

PART 2. LINE EXTENSIONS

PART 3. METER READING, BILLING, COLLECTION AND TERMINATION OF SERVICE PROCEDURES

PART 4. DISPUTE REQUIREMENTS

DEFINITIONS

1. ABBREVIATIONS: Certain references, organizations and regulatory agencies have been abbreviated to acronyms throughout as a matter of convenience.

   ACC - Arizona Corporation Commission

   NEC - National Electrical Code

   NESC - National Electrical Safety Code

   NRUCFC (CFC) or CFC - National Rural Utilities Cooperative Finance Corporation

   RRLEP – These Rules, Regulations & Line Extension Policies

   RUS - Rural Utilities Service

2. ADVANCE IN AID OF CONSTRUCTION (ADVANCE): Funds provided to the Cooperative by the Applicant under the terms of a line extension agreement the value of which may be refundable.

3. AGREEMENT: Synonymous with "Contract" as used herein.

4. APPLICANT: Any person, firm, agent, organization, corporation or governmental body applying for electric service from the Cooperative.

5. APPLICATION: A request to the Cooperative for electric service, as distinguished from an inquiry as to the availability or charges for such service.

6. ARIZONA CORPORATION COMMISSION: The regulatory authority of the State of Arizona having jurisdiction over Trico Electric Cooperative, Inc., abbreviated as "ACC" in these RRLEP.

6. AUTOMATIC METER READING (AMR): Automatic Meter Reading (AMR) is the remote collection of consumption data from Customers' utility meters using telephony, radio frequency, power-line and satellite communications technologies.

7. BILLING DEPOSITS: As used in Sections 119 through 126 of these RRLEP, it shall be deemed to mean deposits made by Customers as a guaranty of the payment of the bills for electric service rendered by the Cooperative.

8. BILLING MONTH: The period between any two regular readings of the Cooperative's meters at approximately 30 day intervals.

9. BILLING PERIOD: The time interval between two consecutive meter readings that are taken for billing purposes.

10. CODES: Applicable electric Codes may be the NEC the NESC any Rule or Regulation adopted by RUS, or by a City, Town, County and/or State authority. Any such permitting, clearance requirements or specification the Cooperative deems necessary and or prudent in accordance with sound engineering practices and safety guidelines.

11. CONNECTED LOAD: Total of the nameplate ratings or measured load of the electrical equipment connected to the electrical installation or system.

12. CONTRIBUTION IN AID OF CONSTRUCTION (CONTRIBUTION): Funds provided to the Cooperative by the Applicant under the terms of a line extension agreement or service connection Tariff, none of which is refundable.

13. COOPERATIVE: Trico Electric Cooperative, Inc.

14. COOPERATIVE EQUIPMENT: The service lines, meter installations, structures, devices, apparatus, hardware and other facilities installed by or on behalf of, and/or owned by, the Cooperative and/or other transmission and distribution facilities of the Cooperative's system.

15. COOPERATIVE'S SPECIFICATIONS: Established standards and requirements supplied to Customers to obtain, construct, or maintain their electric service equipment, in accordance with applicable Codes, sound engineering, construction and financial practices.

16. CUSTOMER: The person or entity in whose name service is rendered, as evidenced by the signature on the application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service.

17. CUSTOMER CHARGE: The amount the Customer must pay the Cooperative for the availability of electric service, excluding any electricity used, as specified in the Cooperative's Tariffs.

18. CUSTOMER'S SERVICE ENTRANCE: In general, all conductors, devices, apparatus, and hardware on the Customer's side of the Point of Delivery, except the Cooperative's meter installation.

19. DAY: Calendar day.

20. DEMAND: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units.

21. DEVELOPER: Any individual, partnership, corporation, governmental agency, or other organization, funding and/or developing lots or parcels of land for use, sale or lease, either improved or unimproved with real property improvements on such lots or parcels.

22. DISTRIBUTION LINES: Any of the Cooperative's power system lines operated at distribution voltages below 69 kV.

23. EFFECTIVE DATE: The effective date of these RRLEP, as approved by the ACC.

24. ELECTRICAL SERVICE: The availability of electric energy, metered or otherwise, available to the Customer within established standards of voltage and frequency to the Point of Delivery.

25. ELDERLY: A person who is 62 years of age or older.

26. ENERGY: Electrical energy, expressed in kilowatt-hours (kWh).

27. HANDICAPPED: A person with a medically diagnosed physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out activities of daily living or protect oneself from neglect or hazardous situations without assistance from others.

28. ILLNESS: A medical ailment or sickness for which a residential Customer obtains a verifiable document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

29. INABILITY TO PAY: Circumstances where a residential Customer:

    A. Is not gainfully employed and unable to pay; or

    B. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that the Customer receives his bill and can obtain verification of that fact from the government welfare assistance agency; and

    C. Has an annual income below the published federal poverty level and can produce evidence of this; and

D. Signs a declaration verifying that the Customer meets one of the above criteria and is either Elderly, Handicapped, or suffers from Illness.

30. INTERRUPTIBLE ELECTRIC SERVICE: Electric service that is subject to interruption as specified in the Cooperative's Tariff.

31. KILOWATT (kW): A unit of power equal to 1,000 watts.

32. KILOWATT HOUR (kWh): Electric energy equivalent to the amount of electric energy delivered in one hour when delivery is at a constant rate of 1 kilowatt.

33. LINE EXTENSION: The lines and equipment necessary to extend the electric distribution system of the Cooperative to provide service to one or more additional Customers.

34. MASTER METER: A meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

35. MEMBER: Any Member of the public, including person, firm, association, corporation and bodies politic or subdivision thereof, who has qualified for Membership as provided for in the By-Laws of the Cooperative.

36. METER: The instrument for measuring and indicating or recording the flow of electricity that has passed through it.

37. METER INSTALLATION: The meter(s) and auxiliary devices and hardware, if any, constituting the Cooperative's equipment needed to measure energy use and/or billing demand supplied to the Customer.

38. METER TAMPERING: Any situation where a meter or associated devices and wiring has been illegally altered. Common examples are but are not limited to; meter bypassing, use of magnets to slow the meter recording, and broken meter seals.

39. MINIMUM CHARGE: The amount the Customer must pay for the availability of electric service, including an amount of usage, as specified in the Cooperative's Tariffs.

40. NEW SERVICE ESTABLISHMENT FEE: A charge as specified in the Cooperative's Tariffs for service requiring new construction.

41. PERMANENT SERVICE: Electric service, which in the opinion of the Cooperative, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature.

42. PERSON: Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

43. POINT OF DELIVERY: The point where facilities (whether owned, leased, or under license by a customer) connect to the Cooperative's facilities, as denoted in the Cooperative's electric service specifications or by written agreement.

44. POWER: The rate of generating, transferring or using electric energy, usually expressed in kilowatts.

45. PREMISES: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.

46. PROPER NOTICE: Unless specified otherwise, a written message delivered by first class mail, via email, or in person by one party to the other at the recipient's last known address, the period of notice commencing from the date of email delivery or mailing.

47. REGULAR HOURS: The hours 8:00 a.m. to 4:30 p.m. Monday through Friday shall be considered regular hours, except for Cooperative holidays. However, service hours may be worked at hours different from those listed as regular hours.

48. RESIDENTIAL USE: Service to Customers using electricity for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, residential water well and other residential uses and includes use in apartment buildings, mobile home parks, and other multiunit residential buildings.

49. SERVICE AREA: The territory in which the Cooperative has been granted a Certificate of Convenience and Necessity (CC&N) and is authorized by the law to provide electric service.

50. SERVICE AVAILABILITY CHARGE: A charge for the purpose of maintaining adequate revenue to cover the operating costs of an extension of line whenever service is idle for all or part of the time or is in an environment that requires higher than average operating costs.

51. SERVICE CONNECTION/DISCONNECTION: The attachment/detachment of electric service by an authorized representative of the Cooperative including operation of Customer owned disconnect devices, if appropriate for safety reasons.

52. SERVICE ESTABLISHMENT: The establishment of electric service to the Customer when the Customer's facilities are ready and acceptable to the Cooperative and the Cooperative needs only to install or read a meter or turn the service on.

53. SERVICE LINE: The line extending from a distribution line or transformer to the Customer's premises or Point of Delivery.

54. SERVICE RECONNECT CHARGE: The charge as specified in the Cooperative's Tariffs which must be paid by the Customer prior to reestablishment of electric service each time the electricity is disconnected for nonpayment or whenever service is discontinued for failure otherwise to comply with the Cooperative's Tariffs, or these RRLEP.

55. SERVICE REESTABLISHMENT CHARGE: A charge as specified in the Cooperative's Tariffs for service at the same location where service disconnection was made for the same Customer.

56. SINGLE FAMILY DWELLING: A house, an apartment, a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as a permanent home.

57. SPINE FACILITIES OR BACKBONE FACILITIES: A large capacity electric distribution system generally not directly connected to individual lots and designed, sized, and constructed to provide adequate service of the proper phase and voltage to the boundary of blocks or large parcels within an approved Master Planned Development in which such blocks or parcels are intended to be subdivided in the future into platted blocks or subdivisions for residential and commercial uses; or the large capacity electric distribution system required to serve an area comprised of a large subdivision or several subdivisions or many platted subdivisions which are not part of a Master Planned Development but which by their proximity to each other and by their zoned uses are similar in nature to a Master Planned Development, and in this event such spine system may be adjacent to individual lots.

58. TARIFFS: The documents filed with the ACC which list the services and products offered by the Cooperative and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products.

59. TEMPORARY SERVICE: Service to premises or enterprises which are temporary in character, or where it is known in advance that the service will be of limited duration. Service which, in the opinion of the Cooperative, is for operations of a speculative character

is also considered temporary service and will be required to make an advance for the cost of retiring the service .

60. TERRITORIAL EXTENT: The RRLEP will be effective and apply throughout the Service Area of the Cooperative by an order or orders of the ACC or by judgment of the courts of Arizona, or by the specific orders of approved rate Tariffs of the ACC, in which such event modifications shall govern where applicable.

61. THIRD PARTY NOTIFICATION: A notice sent to an individual or a public entity willing to receive notification of the pending discontinuance of service of a Customer of record in order to make arrangements on behalf of said Customer satisfactory to the Cooperative.

62. TRICO: Trico Electric Cooperative, Inc.

63. WEATHER ESPECIALLY DANGEROUS TO HEALTH: That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanographic and Administration Service, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

PART 1.
APPLICATION FOR ELECTRIC SERVICE

101. APPLYING FOR ELECTRIC SERVICE

Trico may require a new Applicant for service to appear at Trico's offices at 8600 W. Tangerine Rd., Marana, Arizona, to produce proof of identity and sign the appropriate application form or contract before service is supplied by Trico.

102. APPLICATION FOR SERVICE

A. The application for service form may require, but not necessarily be limited to, the following information:

1. Name or names of Applicant(s).
2. Service address or location and telephone number.
3. Billing address/telephone number if different from service address.
4. Address where service was previously provided and email address (when available)
5. Date Applicant will be ready for service.
6. Statement as to whether premises have been previously supplied with electric service, and if so, date service was discontinued and the reason therefore.
7. Purpose for which service is used.
8. Statement as to whether Applicant is owner, tenant or agent for the premises. For tenants, a copy of the signed rental agreement and contact information for owner.
9. Information concerning the energy and demand requirements of the Customer.
10. Type and kind of life support equipment used, or to be used, by the Customer.
11. Applicant's social security number or driver's license number.
12. Applicant's verification of legal age.
13. Name, phone number, relationship and address of Applicant's closest living relative not living in the home.

B. Customer specific information shall not be released without specific prior written authorization unless the information is requested by law enforcement or other public agency, or is requested by the ACC or its Staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer.

C. Where service is requested by two or more individuals at the same location, Trico has the right to collect the full amount owed from any one of the Applicants.

D. In the absence of a signed application or contract for service, the supplying of electric service by the Cooperative and the acceptance thereof by the Customer shall be deemed to constitute an agreement by and between the Cooperative and Customer for furnishing and receiving electric service under the Cooperative's applicable rates, minimums and provisions for making electric service available.

103. DOUBTFUL PERMANENCY

If, in the Cooperative's opinion, the nature of the Customer's requirement for electric service is doubtful as to whether it constitutes Permanent Service, then the Customer must enter into a contract with the Cooperative and pay the entire cost of construction, including any necessary equipment to serve the Customer (e.g., transformers and associated structures), as well as the cost of retirement of facilities to be installed for the purposes of providing service to the Customer.. The contract shall include provisions that when the permanent nature of the service has been established to the satisfaction of the Cooperative, the RRLEP that pertain to Permanent Service shall be applicable.

104. EXTENSION OF LINE REQUIRED

When an extension of the Cooperative's electric lines is requested, the Cooperative shall advise the Applicant(s) of the provisions of the line extension policies in Sections 201-217, including the costs associated with the proposed line extension. Provisions of the line extension policy are limited to services applicable in the Cooperative's approved Tariffs, utility grade quality of power, and construction is limited to the Cooperative's construction standards. Provisions of the line extension policy are limited to the Cooperative's established alternating nominal distribution voltages 14.4/24.9 kV, Y-Y transformation and construction limited to the Cooperative's construction standards. Other distribution voltages and transmission voltages may be provided on case-by-case basis. The Cooperative has established alternating nominal transmission voltage of 69kV or 115kV that are available in many areas of the Cooperative's system.

105. SERVICE BEYOND SCOPE OF LINE EXTENSION POLICY

When the service requested is different from the standard conditions as noted in Section 104 and elsewhere in this policy, service may be extended to the Applicant(s) under a separate contractual agreement which shall be filed with the ACC.

106. CONDITION FOR SUPPLYING SERVICE

The Cooperative reserves the right to determine the conditions under which an extension will be granted. Conditions for service and extending service to the Customer will be based upon the following:

A. Customer has wired his premises in accordance with the applicable Codes.

B. Customer has installed the electric service entrance equipment in a suitable location and with suitable protection so that the loss of power or the partial loss of voltage, or phases does not damage the Customer's facilities, electric system, and or appliances.

C. In case of temporary construction service, the electric service entrance equipment shall conform to 106.A and 106.E.

D. All such installations shall be in accordance with the Cooperative's specifications and located at an outdoor location accessible to the Cooperative.

E. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper rights-of-way locations.

F. Developers shall have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

G. The Customer agrees to have his installation comply and continue to maintain compliance with the applicable Codes. The Customer will also provide, at their own expense all permitting, licensing, clearances and processes and periodic inspections under their control for which they are responsible, prior to the service being connected.

H. The Customer will be responsible for the electric bills of all services.

I. Customer agrees that failure to maintain compliance with the Codes is cause for disconnection of the service. Code compliance is required before service will be restored.

J. A reduced starter acceptable to the Cooperative shall be installed by the Customer for all 200 HP motors and above and may be required by the Cooperative for motors 40 HP and above.

107. IDENTIFICATION OF LOAD AND PREMISES

The premises and electric load to be served by the Cooperative shall be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Cooperative shall be required to act upon a request for electric service. Existing electric with multiple services at the premises may require that the Customer provide the Cooperative's meter number for the service they wish to connect.

108. IDENTIFICATION OF RESPONSIBLE PARTY

The identity of the party(ies) responsible for accounts in the name of any Customer shall be established in a manner acceptable to the Cooperative. Any person applying for service to be connected in the name of or in care of another Customer shall furnish to the Cooperative acceptable written approval from that Customer guaranteeing payment of all bills under the account. Application for service by a minor shall be subject to written assurance of a party responsible for such service as required by the Cooperative. The Customer is responsible in all cases for service supplied to the premises until the Cooperative has received proper notice of the effective date of termination or transfer of service. The Customer shall also promptly notify the Cooperative of any change in billing address.

109. ASSIGNMENT OF RATE TARIFF

The Cooperative shall use its best efforts to assign the appropriate rate Tariff for the customer's service based on the available data at the time of the service application. The Cooperative shall use its best efforts to notify the Customer of the applicable rate Tariff if the Customer's service classification has changed after initial application, and shall not be required to refund the difference in charge under different rate Tariffs. Upon written notification of any material changes in the Customer installation or load conditions, the Cooperative will assist in determining if a change in rate Tariff is desirable, but not more than one such change at the Customer's request may be made within any 12-month period.

110. TAMPERING WITH OR DAMAGING COOPERATIVE EQUIPMENT

The Customer agrees, when accepting service, that no one except authorized Trico representatives shall be allowed to remove or replace any Cooperative equipment installed on the Customer's property. The Customer will be held responsible for any broken seals, tampering, or interfering with the Cooperative's meter(s), equipment, or property installed on the Customer's premises. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or Customer's wrongful act or omission on the part of any of the Customer's agents, employees, licensees, or contractors. The Cooperative also has the right to refer any matter regarding tampering to the appropriate law enforcement authorities as a criminal matter, including for criminal damage to utility equipment.

111. GROUNDS FOR REFUSAL OF SERVICE

The Cooperative may refuse to establish service if any of the following conditions exist:

A. The Applicant is indebted to the Cooperative and the Applicant has not paid the outstanding balance and fees in full.

B. A condition exists which in the Cooperative's judgment is unsafe or hazardous to the Applicant, the general population, or the Cooperative's personnel or facilities.

C. Applicant refuses to provide the Cooperative with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements.

D. Customer is known to be in violation of any of the Cooperative's Tariffs filed with the ACC.

E. Failure of the Customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer, and which the Cooperative has conditioned providing service upon.

F. Applicant falsifies or misrepresents his or her identity for the purpose of obtaining service.

G. Applicant is in violation of these RRLEP or any applicable Rule or regulation of the ACC or any applicable law, or is in default as to any prior agreement between the Applicant and the Cooperative.

H. Customer has failed to comply with the Codes or permitting/inspection requirements.

112. SCHEDULING OF SERVICE ESTABLISHMENT

After an Applicant has complied with the Cooperative's application and deposit requirement, the requirements of Sections 104-106, and has been accepted for service by the Cooperative, the Cooperative shall schedule that Customer for service establishment.

113. SERVICE ESTABLISHMENT EXCEPTION

Service establishments shall be scheduled for completion within five working days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five working day limitation.

114. SERVICE ESTABLISHMENT BY THE COOPERATIVE

Service establishment shall be made only by a qualified Cooperative service representative or its agent or contractor.

115. TEMPORARY SERVICE PAYMENT REQUIREMENTS

Applicants for Temporary Service may be required to pay the Cooperative in advance of service establishment, a contribution in aid of construction, based on the estimated cost of installing and removing the facilities, less any salvage, necessary for furnishing the desired service. Temporary Service must meet the requirements of any and all applicable Codes as defined in these RRLEP.

116. TEMPORARY SERVICE - LESS THAN ONE MONTH

Where the duration of service is to be less than one month and the Applicant does not have any outstanding debts to the Cooperative, the Applicant may also be required to advance a sum of money equal to the estimated bill for service and a service establishment fee in lieu of a minimum-security deposit.

117. TEMPORARY SERVICE - MORE THAN ONE MONTH

Where the duration of service is to exceed one month, the Applicant may also be required to meet the deposit requirements of the Cooperative.

118. CHANGE OF CLASSIFICATION

If at any time during the term of the agreement for temporary services the character of a temporary Customer's operations change so that in the opinion of the Cooperative, the Customer is classified as permanent, the terms of the Cooperative's RRLEP applicable to Line Extensions will apply. Cost of retirement advance shall be refunded to the Customer once the service is no longer classified as temporary.

119. BILLING DEPOSIT REQUIREMENTS

The Cooperative will not require a deposit from an Applicant for service if the Applicant is able to meet any of the requirements below:

1. The Applicant has existing service with the Cooperative of a comparable nature, was not delinquent in payment (including returned payments) more than twice during the last 12 consecutive months, has not been disconnected for non-payment, nor had more than two insufficient funds checks, e-checks, credit card or other electronic payments declined.
2. The Applicant can produce a letter of credit from a current electric utility receiving service for a minimum of the past two years; and was neither delinquent in payment more than twice during the last 12 consecutive months of service nor was disconnected for non-payment.

120. BILLING DEPOSIT RECEIPT

The Cooperative may issue a nonnegotiable receipt to the Applicant for the billing deposit. The inability of the Customer to produce such a receipt shall in no way impair his right to receive a refund of the billing deposit, if it is reflected on the Cooperative's records.

121. INTEREST ON BILLING DEPOSITS

Billing Deposits shall be interest bearing; the interest rate and method of calculation is defined in the Schedule of Special Charges, Interest on Billing Deposits clause.

122. BILLING DEPOSIT REFUND

Billing deposits will automatically be refunded by applying the billing deposit and accrued interest to the account by the Cooperative after 12 consecutive months, during which time the Customer has not been delinquent more than two times in a 12-month period, or at the discretion of the Cooperative at any time before service is discontinued. Upon discontinuance of service, the Cooperative shall have a reasonable time, but not less than three working days (Monday through Friday excluding holidays) in which to read and remove its meters and to ascertain that the obligations of the Customer have been duly performed before being required to return a billing deposit. Upon final discontinuance of the use of the service and full settlement of all bills by the Customer, any billing deposit, not previously refunded, with accrued interest, (if any), in accordance with the provisions of this policy will be returned to the Customer or at the Cooperative election, it may be applied to the payment of any unpaid accounts of the Customer and the balance, (if any), returned to the Customer. Deposits paid due to tampering will be held for a minimum of two years or applied to the final bill, if service is terminated before the end of the two-year minimum.

Upon written request, an existing deposit may be transferred to another account holder if the deposit is eligible for refund or if a vacating customer wishes to transfer his/her deposit to the new tenant and the final bill has been paid in full.

123. BILLING DEPOSIT AMOUNT

The amount of a billing deposit required by the Cooperative shall be determined according to the following terms:

A. Residential Customer billing deposits may be equal to no more than two times that of the Customer or customer class, estimated average monthly bill.

B. Non-residential Customer billing deposits may be equal to no more than two and one-half times that of the Customer's estimated average monthly bill.

124. BILLING DEPOSIT ADJUSTMENT

A. The Cooperative may review the Customer's usage after service has been connected and adjust the billing deposit amount based upon the Customer's actual usage.

B. The Cooperative may require a residential Customer to establish or reestablish a billing deposit if the Customer has become delinquent in the payment of two monthly bills within a 12 consecutive month period or has been disconnected for service during the last 12 months.

125. BILLING DEPOSIT PER METER

A separate billing deposit may be required for each meter installed.

126. BILLING DEPOSITS AND SERVICE SUSPENSION

Customer billing deposits shall not prevent the Cooperative from terminating the agreement for service with a Customer, or suspending service for any failure in the performance of Customer obligations under the agreement for service, or any violation of the Cooperative's RRLEP in effect from time to time as approved by the ACC.

127. OBLIGATIONS OF MEMBER

In addition to the provisions of these RRLEP and the Cooperative's Tariffs, each Member shall be bound by the Articles of Incorporation and By-Laws of the Cooperative, as the same may be amended from time to time. Customers who elect not to become a Member shall be bound by these RRLEP and the Cooperative's Tariffs.

128. MEMBERSHIP LIMIT

No Customer may hold more than one membership and a membership may be held jointly by a legally married couple pursuant to the provisions of the By-Laws of the Cooperative.

129. RESPONSIBILITY OF THE COOPERATIVE

The Cooperative shall use reasonable diligence to provide or continue to provide electric service; but if in the event service fails, is interrupted, curtailed, becomes defective or becomes unlawful to provide, due to any cause that is beyond the reasonable control of the Cooperative (including from acts of God or the public enemy, accidents, strikes, labor troubles or by action of the elements, the inability to secure rights-of-way, governmental permits, or certificates, franchises or licenses) then the Cooperative will not be liable for any inability to provide such service. The Cooperative shall also not be liable to the Customer or any other person for damages resulting from failures, interruptions or defects of service or any consequential damages sustained by the Customer or person due to any such failure, interruption or defect of service.

130. RATE TARIFFS

The Cooperative shall make available, upon Customer request, the rate Tariff pursuant to which the Customer receives electric service from the Cooperative.

131. TARIFFS AND RRLEP

The Cooperative shall make available upon Customer request a summary of the Cooperative's Tariffs or the Cooperative's RRLEP concerning:

A. Billing Deposits

B. Termination of service

C. Billing and collection

D. Complaint handling

These RRLEP will be effective and apply throughout the Service Area of the Cooperative by an order or orders of the ACC or by judgment of the courts of Arizona, or by the specific orders of approved rate Tariffs of the ACC, in which such event modifications shall govern where applicable.

132. RECORD OF CONSUMPTION

The Cooperative upon request of a Customer shall provide a statement of actual consumption by such Customer for each billing period during the prior 12 months unless such data is not reasonably attainable.

133. CUSTOMER RIGHTS

The Cooperative shall inform all new Customers of their right to obtain the information specified in Section 130, 131 and 132.

134. RESPONSIBILITY OF THE CUSTOMER

The Customer, in addition to the other responsibilities set forth in these RRLEP, shall be responsible for:

A. Use of electric service.

B. The repair or maintenance of Customer-owned equipment beyond the Point of Delivery, including any condition that adversely affects the Cooperative's service to the Customer or to others.

C. Prompt notification to the Cooperative by the fastest available means of outages.

D. Prompt notification to the Cooperative of any material changes in the Customer's installation or load conditions.

E. Prompt notification to the Cooperative of any other conditions in the Customer's electric service resulting in substandard or irregular electric service.

F. The Customer shall provide all utility easements and access as required under Section 145 at no cost to the cooperative.

135. SERVICE CALL FEES

In general, there is no charge to the Customer for service calls related to voltage problems, malfunctions of the Cooperative's equipment and other areas where the Cooperative is responsible. The Cooperative may charge a fee for the services defined below in accordance with the applicable Tariffs of the Cooperative. The amount of the service fee will be determined by the type of personnel needed and whether the work is performed during working or nonworking hours. Reasonable efforts will be made to advise the Customer about appropriate service call fees before the service call begins. Some examples of these service calls are (but are not limited to) the following:

A. Each Customer may be charged a fee for the Service Establishment, reestablishment, or reconnection of utility services, including transfers of service or return trips in the event the initial trip was unsuccessful due to the fault of the Customer. The Service Establishment fee shall entitle the Customer to one service connection. The Service Establishment fee is non-refundable, non-transferable and does not apply against a final or any other bill rendered by the Cooperative to the Customer.

B. A response to a power interruption call where it is determined that the Customer's equipment is at fault and there is electricity at the Point of Delivery.

C. An interruption caused by the Customer's willful act or omission, negligence or failure of Customer-owned equipment, even though the Cooperative is unable to perform any work beyond the Point of Delivery.

D. The Customer's service was previously disconnected for non-payment, unlawful use of service, misrepresentation to the Cooperative, unsafe conditions, threats to Cooperative personnel or property, failure to permit access, detrimental effects of Customer loads on the Cooperative system, failure to establish credit and/or sign an agreement for service, or any other reason authorizing the Cooperative to make such disconnection.

E. A reestablishment of electric service to be reconnected when the same Customer who requested the service to be disconnected, remains a resident at the same premises.

F. A return trip to the same premises when the Customer fails to comply with the Cooperative's conditions for supplying service or fails to supply access to the premises for the initial trip.

136. SERVICE INTERRUPTION

The Cooperative may temporarily suspend service to make repairs, replacements, maintenance, tests or inspections of Cooperative equipment or to make tests, inspections, connections or disconnections of Cooperative service. The Cooperative shall make reasonable efforts to notify the Customer about the need for and the duration of a planned service interruption, but it may suspend service in an emergency situation without prior notice to the Customer.

137. DAMAGES TO THE COOPERATIVE

In the event any of the causes of interruptions set forth in Section 135 or any negligence by the Customer or Customer's electric service cause damage to the Cooperative's property or personnel or the ability of the Cooperative to provide service to others, the responsible party shall be fully liable to the Cooperative therefor and the service charges set forth in such Sections shall not affect the right to recover the amount of such damages.

138. SERVICE CHARGES DUE

The service charges and damages referred to in Sections 135 and 137 shall be added to the Customer's monthly bill and be subject to collections and termination. The Customer must pay all charges for reconnection of any service disconnected for non-payment prior to reconnection.

139. MOBILE HOME PARKS

A. The Cooperative shall have the right to refuse service to all new construction of and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is metered to each unit by the Cooperative. This includes the Cooperative having the right to refuse any Master Meter arrangement for the expansion of such existing parks. Line extensions and service connections to serve such expansion shall be governed by the Line Extension and Service Connection Policy of the Cooperative.

B. Permanent residential mobile home parks for the purpose of this Section shall mean mobile home parks where, in the opinion of the Cooperative, the average length of stay for an occupant is a minimum of six months.

C. For the purposes of this Section, expansion means the addition of permanent residential spaces in excess of that existing at the effective date of this Section.

140. RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS, AND OTHER MULTI-UNIT RESIDENTIAL BUILDINGS

A. Trico will not allow any Master Meter arrangement for construction of any new apartment complex, condominium, or multi-unit residential building unless:

1. a centralized heating, ventilation and/or air conditioning system will serve all of the buildings within the apartment or condominium complex; and

2. the contractor can provide to the Cooperative an analysis demonstrating that the central unit will result in a favorable cost benefit relationship.

B. At a minimum, the cost/benefit analysis should consider the following elements for a central unit as compared to individual units:

1. Equipment and labor costs
2. Financing costs
3. Maintenance costs
4. Estimated kWh usage
5. Estimated kW demand on a coincident demand and non-coincident demand basis (for individual units)
6. Cost of meters and installation
7. Customer account cost (one account vs. several accounts)

141. CUSTOMER PROVIDED FACILITIES

Each Customer obtaining service shall be responsible for all electric facilities on the Customer's side of the Point of Delivery, including the service entrance and the meter socket. In addition, Customers obtaining 200 amp or larger service may be responsible for the service lines as determined by the Cooperative.

142. METER LOCATION

Meters and service switches in conjunction with the meter shall be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection and where such activities will not cause intolerable interference and inconvenience to the Customer. The Customer shall provide and maintain, without cost to the Cooperative, at a suitable and easily accessible location, sufficient and proper space for installation of meters as set forth in the Codes and/or Trico's specifications.

143. METER SERVICE LINE ALTERATION

Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer shall provide and have installed at his expense all wiring materials and equipment necessary for relocating the meter and service line connection and the Cooperative may make a charge not to exceed the actual cost for moving the meter and/or service line as set forth in Section 203.

144. COOPERATIVE FACILITIES

A. The Cooperative shall provide facilities adequate to service the electric load agreed upon at the time of application for service or service upgrade in accordance with applicable Tariffs and electric utility standards, but not electric load added after the last effective service agreement. If the Customer has any question as to the adequacy of the Cooperative's electric facilities then the Customer is responsible to obtain whatever assurance necessary to alleviate those concerns and the Cooperative is obligated to advise the Customer of the process and, if necessary, costs to respond to the Customer's concerns.

B. The cost of any service line in excess of the size or length required to provide adequate service shall be paid as set forth in Sections 104 and 105.

145. RIGHTS-OF-WAY

The Cooperative shall be granted rights-of-way and easement(s) over the property of the Customer, of sufficient width for the construction, maintenance, operation, repair, replacement, relocation, removal or use of any and all wire, poles, machinery, supplies, equipment, metering and regulating and other apparatus and fixtures necessary or convenient for the supplying of electric service to the Customer. The Cooperative shall be given safe and unimpaired access at reasonable times to the premises of the Customer for the purpose of reading meters, testing, repairing, relocating, removing or exchanging any or all equipment or facilities necessary to provide or remove electric service to the Customer. Immediate and unannounced access may be necessary when the Cooperative is dealing with an outage or emergency. The required easement(s) and access shall be conveyed to the Cooperative prior to service being made available to the Customer without cost to the Cooperative. The Cooperative may discontinue service after proper notice is issued if there are violations of the required safe and unimpaired access.

146. OBLIGATION FOR RIGHTS-OF-WAY

The Cooperative shall not be obligated to bear any part of the cost of obtaining rights-of-way, easements, licenses or permits. The Customer may be required to put up a non-interest bearing cost deposit(s) before work to obtain said rights-of-way can begin or continue. Any part of the deposit not used for obtaining rights-of-way may be applied toward and become part of the deposit required as set forth in Section 119 or Part 2 of this policy.

It is the Customer or Applicant's responsibility to obtain the right-of-way from all third parties; however, the Cooperative may assist when resources exist to do so, at the expense of the Customer. It is the Customer or Applicant's responsibility to notify the third parties, neighbor(s) and/or adjacent landowners of the design, surveying and construction activities that could affect them or their surroundings.

147. CUSTOMER FACILITIES IN RIGHTS-OF-WAY

When the Cooperative discovers that a Customer or his agent is performing work or has constructed facilities adjacent to or within an easement or rights-of-way and such work, construction or facility or establishes or owns any vegetation, ornamental or not, that obstructs or poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, rules, regulations, Codes or Trico's specifications or significantly interferes with the Cooperative's access to equipment, the Cooperative shall notify the Customer or his agent and shall take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

148. RIGHTS-OF-WAY EASEMENTS FOR ELECTRIC DISTRIBUTION AND SERVICE LINES

The Cooperative shall construct or cause to be constructed and shall own, operate and maintain all electric distribution and service lines along public streets, roads and highways and on public lands and private property which the Cooperative has the legal right to occupy.

149. RIGHTS-OF-WAY IN SUBDIVISIONS

Rights-of-way and easements suitable to the Cooperative must be furnished by the developer at no cost to the Cooperative and in reasonable time to meet service requirements. No electric facilities shall be installed by the Cooperative until the final grades have been established and furnished to the Cooperative. In addition, the easement strips, alleys, and streets must be graded by the developer to standards determined by the Cooperative, before the Cooperative will commence construction. Such clearance and grading must be maintained by the developer during construction by the Cooperative.

150. RELOCATION OF FACILITIES

If, subsequent to construction, the clearance or grade is changed in such a way as to require relocation of facilities, or if deemed advisable by the Cooperative to require changing any underground to overhead or overhead to underground, the cost of any damage, relocation, replacement and/or resulting repairs shall be borne by the developer or the property owner of the real property which adversely affected the Cooperative facilities.

151. SERVICE UPGRADE POLICY

When the Cooperative receives written notification from the Customer of plans to upgrade an existing service panel or plans to increase the load demand or in any way alter the existing service configuration or source voltage, the Cooperative shall determine the ability and efficacy of its existing facilities to sustain safe, reliable, and adequate service to satisfy the Customer's service changes. The Cooperative will require load information and electrical data from the Customer and Cooperative will determine the alterations, upgrades, replacements, or additions of facilities, if any, required by the Cooperative to accommodate the Customer's changes. The Customer shall be charged the cost of construction and labor associated with retirement of any existing facilities for any service upgrade requiring material changes by the Cooperative. When in the Cooperative's opinion the existing facilities are eligible for replacement related to normal maintenance, a credit for the current value of the replacement materials may be given. The Cooperative shall apply a credit allowance exactly equal to the material and labor cost of any special equipment, such as transformers, required to serve the Customer. The cost of any line extension in excess of that allowed at no charge shall be paid for by the Applicant as a non-refundable Contribution in Aid of Construction. The conditions for supplying or refusing electric service in Sections 106 and 111, respectively, shall apply to service upgrades.

PART 2.
LINE EXTENSIONS

201. STATEMENT OF POLICY

The provisions of this policy shall define the conditions governing line extensions. Extensions of distribution or transmission facilities and lines of existing standard voltages necessary to furnish permanent electric service to Applicants and Customers of the Cooperative will be made by the Cooperative in accordance with the provision of this Part 2 and the Sections in Part 1 and 3 that are applicable, (e.g. 104, 105 and 364). These provisions shall apply throughout the entire Service Area of the Cooperative unless modified by the provisions of an effective rate Tariff or specific order of the ACC, in which cases the provisions of the rate Tariff or order shall govern to the extent applicable.

The Cooperative will construct, own, operate and maintain lines along public streets, roads and highways, which the Cooperative has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Cooperative may be obtained without cost to or condemnation by the Cooperative.

A. Upon request by an Applicant for a line extension, the Cooperative shall prepare without charge, a preliminary sketch and rough estimate of the costs to be paid by the Applicant.

B. Any Applicant for a line extension requesting the Cooperative to prepare detailed plans, specifications, or cost estimates, may be required to deposit with the Cooperative an amount equal to the estimated cost of preparation. The Cooperative, upon request, will make available within 90 days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed line extension. Where the Applicant authorizes the Cooperative to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be non-refundable. If the extension is to include oversizing of facilities to be done at the Cooperative's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdivisions providing the utility with approved plats shall be provided with plans, specifications, or cost estimates within 45 days after receipt of the deposit referred to in Section 208B.

C. When the Cooperative requires an Applicant to contribute funds for a line extension, the Cooperative will furnish the Applicant with a line extension agreement.

D. All line extension agreements requiring payment by the Applicant shall be in writing and signed by both parties.

E. The provisions of this policy shall apply only to those Applicants who in the Cooperative's judgment will be a Permanent Service.

F. In all applications of an equipment allowance of line extension costs, the equipment allowance shall follow the requirements of a Permanent Service Point of Delivery on the Customer's real property, at one location, unless multiple Points of Delivery are deemed by the Cooperative reasonable and economical.

G. The Cooperative will charge a New Service Establishment Fee per service to each Applicant requiring construction of a new service, in accordance with the applicable approved Tariffs.

202. MINIMUM WRITTEN AGREEMENT REQUIREMENTS

Each line extension agreement or cost letter, at a minimum, will include the following information:

A. Name and address of Applicant

B. Proposed service address and location

C. Description of requested service

D. Description and sketch of the requested service, line extension and if in a duly recorded real estate subdivision, of the subdivision with the lot numbers thereof

E. A cost estimate is to include materials, labor, reasonable overhead, and other costs as necessary

F. Payment terms

G. A concise explanation of any refunding provisions if applicable

H. Explanation of required easements, if any, or confirmation of existing easements adequate and legal for Trico's use prior to Trico's commitment to a line extension route and agreement

I. After the easements are obtained and the agreement is signed, the Cooperative will provide the estimated number of days to start construction and the number of days needed to complete construction of the line extension

J. Any service availability charge

203. LINE EXTENSION COSTS

Line extension costs shall be established through use of a power line design program, and using Trico's historical costs, information, and data, to calculate the following:

A. Material

B. Direct labor

C. Overhead: Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs such as:

1. Indirect labor
2. Engineering
3. Transportation
4. Taxes, e.g. (FICA, State & Federal Unemployment which are properly allocated to construction)
5. Insurance
6. Stores expense
7. General office expenses allocated to costs of construction
8. Power operated equipment
9. Employee Pension and Benefits
10. Margins
11. Miscellaneous expenses properly chargeable to construction

D. All extension agreements shall be signed by the Customer, and all applicable deposits and/or contributions in aid of construction shall be paid to the Cooperative, prior to construction.

204. LINE EXTENSION MEASUREMENT

Line extension measurement for design and cost purposes shall be along the most direct and practical route of construction required, and no equipment allowance shall be granted for any facility beyond the most direct and practical route to the nearest practical Point of Delivery as determined by the Cooperative.

205. EXTENSION TO RESIDENTIAL CUSTOMERS

A Equipment Allowance: Upon satisfactory completion of the required site improvements to demonstrate the permanent nature of the Applicant's installation, the Cooperative shall grant an equipment allowance not to exceed $1,500 per Permanent Service, applied as a credit towards the Applicant's line extension fees. In addition, the Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformers and metering equipment, required to serve the customer. The Applicant shall pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to residential Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

206. EXTENSION TO NON-PERMANENT RESIDENTIAL CUSTOMERS

A. Equipment Allowance: Upon satisfactory completion of the required site improvements to demonstrate the permanent nature of the Applicant's installation, the Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformer and metering equipment required to serve the Customer. The Applicant shall pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to non-permanent residential Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

207. EXTENSION TO GENERAL SERVICE 3 AND 4 CUSTOMERS

A. Equipment Allowance: A Customer with an applicable rate Tariff of General Service 3 (GS3) or General Service 4 (GS4) is not eligible for an equipment allowance whatsoever, and is wholly responsible for the full-calculated cost of any line extension, which the Customer will pay as a non-refundable Contribution in Aid to Construction.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to GS3 and GS4 Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

208. OVERHEAD OR UNDERGROUND DISTRIBUTION FACILITIES WITHIN DULY-RECORDED REAL ESTATE SUBDIVISIONS OR COMPARABLE UNRECORDED DEVELOPMENT

A. General Statement: With respect to overhead or underground distribution facilities within a duly recorded subdivision, the Cooperative will be responsible for the construction of the electric facilities for Residential Customers. All Commercial Customers within subdivision will be covered by Sections 201 through 204, and either Section 207 or 209 (whichever is applicable). In the event the extension is underground the Developer of the recorded subdivision shall provide and install at Developer's expense the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes, and other preparation for electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative. At its option, the Cooperative may elect at the Developer's expense to perform the necessary activities to fulfill the Developer's responsibility hereunder; provided, the expense to the Developer is equal to or less than the expense in the event the Developer performed such activities.

B. Application Fee: The Developer shall pay a $75 per lot non-refundable application fee before the Cooperative shall be obligated to commence the electric design for the subdivision, including planning or design of off-site facilities. For extensions in subdivisions not directly connected to facilities providing service to subdivision lots, but that will be connected to the Cooperative's facilities providing service to subdivision lots ("Spine Facilities" or "Backbone Facilities"), the Cooperative shall collect a nonrefundable application fee equal to the design, inspection, and rights-of-way costs. In that case, the fee will be calculated to serve such Spine Facilities, or five percent of the total calculated cost to construct, design, inspect, and obtain right-of-way, of such Spine Facilities, whichever is greater.

C. Agreement: Distribution facilities will be constructed by the Cooperative within a subdivision or development in advance of application for Permanent Service, after the Cooperative and the Developer of the subdivision or development have entered into a written contract which provides, among other things, for:

1. Equipment Allowance for Developers: The Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformers required to serve the future Customers. The Applicant will pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

2. Contribution in Aid of Construction: The total calculated installed cost of such distribution facilities and Spine Facilities, exclusive of transformers, shall be paid to the Cooperative as a non-refundable Contribution in Aid of Construction. The total calculated installed cost shall include all electric facilities that include Spine Facilities or Backbone Facilities required and sized to serve the total construction of the subdivision or development, and may include all or a portion of off-site facility extensions or off-site facility improvements which the Cooperative has deemed necessary to serve the subdivision or development. The Developer shall be required to install all

conduit systems, equipment and transformer basements, and furnish and install all concrete equipment pads per the Cooperative's requirements, including all such conduit and associated facility to the service side of any customer applying for service before the Cooperative is obligated to serve said Customer. The non-refundable lot application fee required per Section 208.B shall be deducted from the total calculated installed cost. A written agreement with a term of five years commencing from the date of completion of construction of these electric facilities, shall be executed by the Developer and the Developer shall pay Trico all deposits in the amounts stated in the agreement prior to the installation of the electric facilities. If after five years, from the completion of the construction of the distribution facilities the development is not complete, the Cooperative shall have the right to execute and record a lien on the unsold portion of the property to secure: (1) the payment by the Developer to the Cooperative of any existing and new service availability charges, which is the fixed fee set forth in the applicable Tariff for idle services; or (2) the cost to the Cooperative to retire or abandon the unused facilities, whichever in the Cooperative's opinion is in the best interest of the Cooperative; or (3) the Cooperative shall have the right to retire any or all of the idle facilities it deems necessary, with proper notice, in accordance with Section 364.

3. Actual Cost of Construction. Within 60 days after the completion of construction, inspection and closeout by the Cooperative of the facilities to serve the subdivision or development, the Cooperative may advise the Developer in writing of the actual costs of such construction. In the event the actual costs are given to the Customer and such actual costs are less than the calculated cost for which payment has been made by the Developer to the Cooperative, the Cooperative shall promptly refund to the Developer the difference. In such event if such actual costs are greater than such calculated cost, the Cooperative shall invoice to Customer and the Customer shall promptly pay such invoiced amount.

D. Service to Residential Customer: Each residential customer or his or her agent (Applicant) within duly recorded real estate subdivisions will be required to make application for service in accordance with Sections 201-205.

209. ALL OTHER EXTENSIONS.

A non-refundable Contribution in Aid of Construction for line extensions is required for all other line extensions of any class or type not otherwise provided in these RRLEP, but which are covered by the standard offer provisions of Section 104. The following formula will determine the amount of the Applicant's non-refundable Contribution in Aid of Construction for such extensions. If the amount calculated below is zero or negative, no Contribution in Aid of Construction is required for provision of electric service.

Cooperative's Allowable Investment = Annual Revenue / Return Factor

Total Project Cost = Direct Cost + System Cost

Applicant's Contribution = Total Project Cost – Cooperative's Allowable Investment

Where:

Direct Cost	=	The cost of distribution or transmission facilities necessary to provide electric service to Customer, determined by estimating all necessary expenditures, including, but not limited to, metering, services, transformers, and rearrangement of existing electrical facilities. This cost includes only the cost of the above-mentioned facilities that are necessary to provide service to the particular customer requesting service and does not include the costs of facilities necessary to meet future anticipated load growth, or to improve the service reliability in the general area for the benefit of existing and future customers.
System cost	=	Cooperative's average allocated investment costs associated with Customer's on-peak and off-peak demands as approved in Cooperative's most recent rate case for the appropriate class of Customer. Investment cost accounts considered in determining the allocated investment costs are those applicable 300 series FERC accounts and other rate base items, including plant held for future use, cash working capital, materials and supplies, prepayments, customer deposits, reserve for insurance and other cost-fee capital.
Annual Revenue	=	Estimated annual revenue from Customer computed from estimated demand and kWh, excluding fuel cost and sales tax.
Return Factor	=	Fixed charge rate, including O&M, taxes, insurance, necessary to convert an annual revenue stream to the total revenue associated with estimated life of project.

The Cooperative's Allowable Investment will be determined based on Annual Revenue for the current 12-month period.

210. CONVERSION OF EXISTING LINE

A. To the extent the provisions of Arizona Revised Statutes, Title 40, Chapter 2, Article 6.1 ("Article 6.1") are applicable, a conversion of overhead to underground lines shall be made pursuant to Article 6.1.

B. In the event that Article 6.1 is not applicable, when requested by Customer or Customers to convert all or a portion of distribution lines from single-phase to three-phase overhead, or single phase to three-phase underground or from overhead to underground, the following shall be applicable to such conversion:

1. The Customer(s) shall provide all utility easements and access as required by Section 145 at no cost to the Cooperative.
2. The Customer(s), at the Customer's (Customers') expense, shall provide the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, in accordance with the specifications and schedules of the Cooperative and local

codes and shall perform all street, curb and sidewalk repairs at the Customer's expense in accordance with local jurisdiction prior to the Cooperative's commencement of the conversion.

3. The Customer(s) shall pay to the Cooperative a Contribution in Aid of Construction the cost of the existing line at present value, less credit for salvage, if any, plus retirement cost, plus any applicable line extension costs, less any applicable equipment allowances, prior to the start of construction.
4. The Customer(s) shall sign any additional agreements, which may include a consensual lien to secure payment of all unpaid obligations of the Customer(s) pursuant to this Section 210, which shall be recorded in the office of the county recorder.

211. ADVANCES UNDER PREVIOUS RRLEP AND CONTRACTS

At the time these new RRLEP are approved by the ACC all existing agreements, contracts, or cost letters with or to customers shall remain in effect in accordance with the term or time period stated in those agreements, contracts, or cost letters; and amounts advanced under the conditions established by a Section previously in effect shall remain nonrefundable or will be refunded in accordance with the requirements of such effective contract under which the advance was made.

212. EXTENSIONS FOR TEMPORARY SERVICE

Extensions for Temporary Service (including for operations of a speculative character or questionable permanency) will be made in accordance with the provisions pertaining to Temporary Service set forth in Section 115 through 118.

213. SPECIAL OR EXCESS FACILITIES

Under these RRLEP, the Cooperative shall install only those facilities which it deems are necessary to render service in accordance with the rate Tariffs. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Cooperative normally would install, the extra cost thereof shall be paid by the Customer.

214. PRIMARY VOLTAGE SERVICE

When the Cooperative agrees to provide primary service to a new or existing Customer, the Point of Delivery shall be determined solely by the Cooperative. The Customer shall provide the entire distribution system between the Point of Delivery and the Customer's load, unless otherwise specified in the written agreement between the Customer and the Cooperative (where the agreement shall provide for facilities charge(s), for the Cooperative's distribution on the Customer's side, from the Point of Delivery). The system will be treated as primary service for the purposes of billing. The Cooperative reserves the right to approve of or require modification of the Customer's distribution plan or system prior to installation and connection with Trico's system. Instrument transformers, meters, poles and all other equipment associated with the primary service metering will be installed by the Cooperative at the Customer's expense. The Customer and the Cooperative will agree on who will pay for the facilities on the Customer's side (load side) of the Point of Delivery. Facilities charge(s) as part of the monthly power bill will include applicable charges for operations, maintenance, depreciation, customer expense, administration expense, and rate of return. Unless otherwise set forth in the written agreement between the Customer and the Cooperative, the Customer will pay, as a Contribution in Aid of Construction, 100 percent of the cost of any line extension – as well as any and all upgrades to the distribution and transmission facilities between the nearest existing Trico power facility capable of providing for the Customer's load and the point of delivery, of such size and capacity required to serve the Customer, less any oversize or excess facilities constructed for the Cooperative's system needs. The Customer will have the option to pay for the cost of all upgrades to the nearest existing facilities that may not otherwise be capable of providing the requested load to the Customer's requested Point of Delivery if it would be the least cost to the Customer.

215. PROTECTIVE EQUIPMENT

The Customer shall provide, own, and maintain such protective equipment necessary to ensure isolation of the Customer's service from the Cooperative's system due to abnormal conditions. It is the responsibility of the Customer to provide protection and/or power -conditioning devices required to provide the quality of power necessary for optimum performance of voltage-sensitive equipment. Voltage sensitive equipment is defined as equipment that does not function with utility grade power, e.g. computers. Some motors may be sensitive to the loss of a phase. It is the Customer's responsibility to protect their equipment from loss of voltage, phase, frequency, or deviation in standard voltage.

216. CUSTOMER GENERATION EQUIPMENT

A. A Customer installing any means of stand-by generation, which is not intended to become interconnected with the Cooperative's service, shall install a double-throw transfer switch that will prevent connection of the Customer's equipment to the Cooperative's power system.

B. A Customer installing any generation equipment intended to operate in parallel with the Cooperative's electric system, must meet all the provisions of the Cooperative's policies and guidelines. The Customer shall make no connections to the electric system without specific inspection and approval by the Cooperative and shall enter into a parallel operation, power sale and interconnection agreement with the Cooperative.

C. The Cooperative shall be notified to inspect, and if satisfactory, approve said connection. Any unapproved installations shall be grounds for immediate disconnection of the Customer's service.

217. RELOCATION OF COOPERATIVE FACILITIES

When the Cooperative is requested to relocate its facilities for the benefit and/or convenience of a Customer, the Customer shall reimburse the Cooperative for the total cost of the work to be performed prior to the start of construction. When the relocation involves underground facilities, the Customer's responsibilities in Section 210 shall apply.

PART 3.
METER READING, BILLING, COLLECTION AND TERMINATION OF SERVICE PROCEDURES

301. FREQUENCY OF METER READING

The Cooperative reserves the right to read meters on a schedule less frequent than monthly where the location is so remote or inaccessible that fewer actual readings are in the best interest of operating economy. However, in no event will meters be read less frequently than every three months. Every attempt shall be made to read meters monthly on as close to the same day as practical. However, meter readings may be scheduled for periods of not less than 25 days or more than 35 days.

302. ESTIMATION OF BILL, FIRST AND SECOND MONTH

If the Cooperative is unable to read the meter on the scheduled meter read date, the Cooperative will estimate the consumption for the first and, if applicable, the second billing period thereafter in accordance with the Estimation Methodology Tariff, Schedule EM as approved by the ACC.

303. ESTIMATION OF BILL AFTER SECOND MONTH

After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Cooperative will make every attempt to secure an accurate reading of the meter.

304. ESTIMATED BILLS

Subject to the provisions of Section 306, estimated bills will be issued according to Trico's Estimation Methodology Tariff, Schedule EM and under the following conditions:

A. Labor shortages or work stoppages beyond the control of the Cooperative.

B. Severe weather conditions or emergencies or which prevent the Cooperative from reading the meter.

C. Circumstances that make it dangerous or impossible to read the meter, including but not limited to: locked gates, blocked access to meters, threatening or abusive customers, vicious or dangerous animals or missing meters.

D. Failure of customer who reads his own meter to deliver his meter reading to the Cooperative in accordance with the requirements of the Cooperative billing cycle.

E. To facilitate timely billing for customers using load profiles.

305. NOTICE OF ESTIMATION

Each bill based on estimated usage will indicate that it is an estimated bill.

306. RECORD OF CONSUMPTION

The registration of the Cooperative's meter at the Customer's Point of Delivery shall constitute evidence of the amount of energy and/or billing demand used by the Customer, except where unmetered service is supplied. However, in the event of failure of the Cooperative's meter or inability of an authorized representative of the Cooperative to obtain an actual reading, a reasonable estimate shall be made per Section 302.

307. RATE TARIFFS BASED ON SINGLE POINT OF DELIVERY

Unless otherwise specifically provided in the rate Tariff or by contract, each of the Cooperative's rate Tariffs are based upon the supplying of electric service to one Customer at a single Point of Delivery and at a single voltage and phase classification, and any additional service supplied to the same Customer at other Points of Delivery or at a different voltage of phase classification shall be separately metered and billed, except as provided in Section 317.

308. MEASURING OF ELECTRIC SERVICE

All energy sold to Customers, and except that sold according to fixed charge Tariffs, shall be measured by commercially acceptable measuring devices owned and maintained by the Cooperative, except where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the ACC.

309. MORE THAN ONE METER

When there is more than one meter at a location, the service and metering equipment shall be so tagged or plainly marked as to indicate the location metered.

310. METER MULTIPLIERS

Meters which are not direct reading shall have the multiplier plainly marked on the meter, meter panel or meter base.

311. RECORDING METER DATA

All data taken from recording meters shall be marked with the date of the record, meter number, Customer information, data multiplier, transformer multiplier(s), date removed and items measured.

312. METER SETTINGS

Metering equipment shall not be set "fast" or "slow" to compensate for supply transformer or line losses.

313. CUSTOMER REQUESTED REREADS

The Cooperative, at the Customer's request, will reread that Customer's meter once within 10 working days after such request by the Customer.

314. REREAD CHARGE

The Cooperative may charge the Customer for any reread at a rate on file and approved by the ACC in Trico's Schedule of Special Charges, if the original reading was not in error. When a reading is found to be in error, the reread shall be at no charge to the Customer.

315. ACCESS TO CUSTOMER PREMISES

The Cooperative shall at all times have the right of safe ingress to and egress from the premises at all reasonable hours for any purpose reasonably connected with the Cooperative's property used in furnishing service, reading meters, and the exercise of any and all rights secured to it by law or these RRLEP. The Cooperative will continue to check the meter, including Automated Meters, periodically or for cause. Failure on the part of the Customer to comply with these RRLEP for access to its meter may lead to the discontinuance of service. An authorized agent/representative of the Cooperative, is authorized to enter any premises using Trico's electricity to inspect the use and quality of the electricity (A.R.S. § 40-431), to read meters, and to connect or disconnect services (A.A.C. R14-2-211).

316. FREQUENCY AND METHODS OF BILLING.

The Cooperative shall bill monthly for services rendered by sending the bill via the United States Mail, e-mail, posting to a secure website or other acceptable means of delivery.

317. COMBINING OF METER READINGS

Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two or more meters will not be combined unless otherwise provided for in the Cooperative's Tariffs.

318. MINIMUM BILLING INFORMATION

Each bill for residential service will contain the following minimum information:

A. Date and meter reading at the start of the billing period or number of days in the billing period

B. Date and meter reading at the end of the billing period

C. Billed usage and demand

D. Rate Tariff number/designation

E. Cooperative's telephone number

F. Customer's name

G. Service account number

H. Amount due and due date

I. Past due amount and subject to termination date

J. Adjustment factor, where applicable

K. Taxes

L. The ACC's address.

319. BILLING TERMS

All bills for electric service are due and payable no later than 15 days from the date the bill is rendered as evidenced in Section 320. The Cooperative shall consider any bill delinquent when payment is not received within this time frame and the Customer may incur a late payment charge.

320. EVIDENCE OF RENDERING DATE

For purposes of this Section, the date a bill is rendered may be evidenced by:

A. The postmark date

B. The mailing date

C. The billing date shown on the bill (however, the billing date shall not differ from the postmark or mailing date by more than two days)

D. The transmission date of electronic bills

321. DELINQUENT BILLS

All delinquent bills for which payment has not been received within five days shall be subject to the provisions of the Cooperative's termination procedures.

322. PLACE OF PAYMENT

All payments shall be made at or mailed to the office of the Cooperative or to the Cooperatives authorized payment agency. Payments can also be made by credit card, e-check, bank draft or recurring credit card payments. No payment shall be deemed made until received by the Cooperative. A service fee may be required on credit card and e-check transactions.

323. APPLICABLE RATE TARIFF

Each Customer shall be billed under the applicable Tariff indicated in the Customer's application for service.

324. FAILURE TO RECEIVE BILLS/NOTICES

Failure by the Customer to receive bills or notices, which were properly placed in the United States mail, by secure website, by e-mail or other acceptable means of delivery, shall not prevent such bills from becoming delinquent nor relieve the Customer of his obligations therein.

325. COMMENCEMENT DATE

Charges for service commence when the service is installed and connection made, whether used or not.

326. METER ERROR CORRECTIONS

If any meter, after testing, is found to be more than three percent three percent in error, either fast or slow, proper correction between three percent three percent and the amount of the error shall be made of previous readings and adjusted bills shall be rendered according to the following terms:

A. For the period of three months immediately preceding the removal of such meter from service for testing, or from the time the meter was in service since last tested, but not exceeding three months since the meter shall have been shown to be in error by the test.

B. From the date the error occurred, if the date of the cause can be definitely fixed.

327. METER TEST / BILLING ADJUSTMENT

No adjustment shall be made by the Cooperative except to the Customer last served by the meter tested.

328. CUSTOMER REQUESTED METER TESTS

The Cooperative shall test a meter upon Customer request, and the Cooperative shall be authorized to charge the Customer for such meter test according to the Tariff on file and approved by the ACC. However, if the meter is found to be in error by more than three percent, no meter-testing fee will be charged to the Customer.

329. UNAUTHORIZED CONNECTIONS/ALTERATIONS

No person, except a representative acting on behalf of the Cooperative shall alter, remove or make any connections to the Cooperative's meter or service equipment.

330. METER SEALS

No meter seal may be broken or removed by anyone other than an authorized representative of Trico acting on behalf of the Cooperative. However, the Cooperative may give its consent to break or remove the seal by an approved electrician, employed by a Customer, when deemed necessary to the Cooperative.

331. METER TAMPERING AND THEFT OF POWER

In cases of tampering with meter installations, interfering with the proper working thereof; or any other theft of service by any person, or evidence of any such tampering, interfering, theft, or service diversion, including the falsification of Customer read meter readings; that service shall be liable to immediate discontinuance of service.

332. TAMPERING AND THEFT CHARGES

Pursuant to Arizona Revised Statutes, Sections 40-491 through 40-495, the Cooperative shall be entitled to collect from the Member/Customer whose name the service is in, the appropriate rate for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also any additional security deposits as well as all expenses incurred by the Cooperative for property damages, investigation of the illegal act, and all legal expenses and court costs if necessary. Arizona law allows Trico to collect triple damages from power thieves.

333. ALTERNATIVE METHODS OF PAYMENT

Customers may pay their bills for electric service furnished them by the Cooperative in the following alternative methods:

A. Payment by cash, bank cashier's check, bank certified check, valid personal check or electronic check drawn on a commercial bank insured by the Federal Deposit Insurance Corporation or a savings and loan association insured by the Federal Savings and Loan Insurance Corporation.

B. Payment by a valid credit card accepted by the Cooperative. Payment by credit card shall not be deemed accepted by the Cooperative unless and until authorized by the bank administering the use of the credit card for the Customers.

C. A service fee may be required on electronic transactions.

334. PAYMENT TRANSACTION RETURN OR CHARGE BACK

The Cooperative shall be allowed to recover a fee, as approved by the Commission, for each instance where Customer tenders payment for electric service with an insufficient funds check, payment transaction return or charge back.

335. METHODS OF PAYMENT AFTER RECEIPT OF TRANSACTION RETURN OR CHARGE BACK

When the Cooperative is notified by the Customer's bank that there is a payment transaction return tendered for electric service, the Cooperative may require the Customer to make payment in cash, by money order, cashier's check, or other means which guarantee the Customer's payment to the Cooperative.

336. CUSTOMER'S OBLIGATION TO RENDER PAYMENT

A Customer who tenders payment transaction return shall in no way be relieved of the obligation to render payment to the Cooperative under the original terms of the bill nor defer the Cooperative's provision for termination of service for nonpayment of bills. In the event a Customer makes a partial payment, the Cooperative may accept the partial payment and apply it on the Customer's account. However, the Customer shall remain liable to the Cooperative for the unpaid portion of the account and for the purpose of these RRLEP; only full payment shall be deemed to constitute payment.

337. PAYMENT TRANSACTION RETURN OR CHARGE BACK LIMITATION

Only cash, money order or cashier's checks will be accepted if two insufficient funds checks, transaction returns or charge backs have been received by the Cooperative within a twelve-month period in payment of any billing. A returned check cannot be paid with another check.

338. PAYMENT TRANSACTION RETURN OR CHARGE BACK LIMITATION AND TERMINATION OF SERVICE

Electric service will be subject to disconnect following the procedure as set forth in Section 355 for payment transaction return or charge backs that have not been made good.

339. LEVELIZED BILLING PLAN

The Cooperative, at its option, may offer its Customers a levelized billing plan.

340. LEVELIZED BILLING PLAN REQUIREMENTS

If the Cooperative offers a levelized billing plan, the Cooperative shall develop, upon the Customer's request, an estimate of the Customer's levelized billing for a 12-month period based upon:

A. Customer's actual consumption history, which may be adjusted for increased past usage and abnormal conditions such as weather variation.

B. For new Customers, the Cooperative will estimate consumption based on the Customer's anticipated load requirements.

C. The Cooperative's Tariffs approved by the ACC applicable to that Customer's class of service.

341. LEVELIZED BILLING PLAN INFORMATION TO CUSTOMER

The Cooperative shall provide the Customer a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly electric bill, and the Cooperative's right to adjust the Customer's billing for any variation between the Cooperative's estimated billing and actual billing.

342. MINIMUM INFORMATION ON MONTHLY LEVELIZED BILL

For those Customers being billed under a levelized billing plan, the Cooperative shall show at a minimum, the following information on the Customer's monthly bill:

A. Actual consumption

B. Amount due for actual consumption

C. Levelized billing amount due

D. Accumulated variation in actual versus levelized billing amount

343. ADJUSTMENTS TO LEVELIZED BILLS

The Cooperative may adjust the Customer's levelized billing in the event the Cooperative's estimate of the Customer's usage and/or cost should vary significantly from the Customer's actual usage and/or cost; such review to adjust the amount of the levelized billing may be initiated by the Cooperative or upon Customer request.

344. DEFERRED PAYMENT PLAN

The Cooperative, prior to termination, may offer to qualifying residential Customers a deferred payment plan for unpaid bills.

345. DEFERRED PAYMENT PLAN AGREEMENT TERMS

Each deferred payment agreement entered into by the Cooperative and the Customer due to the Customer's Inability to Pay an outstanding bill in full shall provide that service will not be discontinued if:

A. Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement.

B. Customer agrees to pay all future bills for utility service in accordance with the billing and collection Tariffs of the Cooperative, unless otherwise noted the deferred portion of the unpaid balance will be due at the same time as normal monthly bills; the deferred balance will be included as a line item on the bill.

C. Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments over a period not to exceed six months.

D. Any Customer utilizing a deferred payment agreement will be required to sign a mutually agreed upon payment schedule. Any Customer failing to meet the terms of the deferred payment plan agreement will be eligible for termination of service without notice.

346. DETERMINING INSTALLMENT PAYMENT SCHEDULE

For the purposes of determining a reasonable installment payment schedule under these RRLEP, the Cooperative and the Customer shall consider the following conditions:

A. Size of the account

B. Customer's ability to pay

C. Customer's payment history

D. Length of time that the debt has been outstanding

E. Circumstances which resulted in the debt being outstanding

F. Any other relevant factors related to the circumstances of the Customer

347. ESTABLISHMENT OF AGREEMENT/TERMINATION DATES

Any Customer who desires to enter into a deferred payment agreement shall execute such agreement prior to the Cooperative's scheduled termination date for nonpayment of bills; Customer failure to execute a deferred payment agreement prior to the scheduled termination date shall not prevent the utility from discontinuing service for nonpayment. A deferred payment agreement may include a late payment charge as approved by the ACC in a Tariff proceeding.

348. REQUIREMENTS OF DEFERRED PAYMENT AGREEMENT

If a Customer has not fulfilled the terms of a deferred payment agreement, the Cooperative shall have the right to disconnect service pursuant to the Cooperative's termination of procedures and, under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

349. CHANGE OF OCCUPANCY

Not less than three working days advance notice must be given to the Cooperative to discontinue service or to change occupancy.

350. OUTGOING PARTY RESPONSIBILITY

The outgoing party shall be responsible for all electric service provided and/or consumed up to the scheduled turn-off date. The outgoing party is also responsible for providing access to the meter so that Trico may obtain a final meter reading.

351. NON-PERMISSIBLE REASONS TO TERMINATE ELECTRIC SERVICE

The Cooperative will not disconnect service for any of the reasons stated below:

A. Delinquency in payment for services rendered to prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises.

B. Failure of the Customer to pay for services or equipment, which are not regulated by the ACC.

C. Failure to pay for a bill to correct a previous under billing due to an inaccurate meter or meter failure if the Customer agrees to pay over a reasonable period of time.

D. The Cooperative will not terminate residential service where the Customer has an inability to pay and is making arrangements for payment, alternative power supply, or to relocate the resident, in the event that:

1. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous or life threatening to the Customer or a permanent resident residing on the Customer's premises, health, or

2. Life supporting equipment used in the home that is dependent on electric service for operation of such apparatus, or

3. Where Weather Especially Dangerous To Health as defined herein or as determined by the ACC occurs.

E. Residential service to ill, elderly, or handicapped persons who have an Inability to Pay will not be terminated until all of the following have been attempted:

1. The Customer has been informed of the availability of funds from various government and social assistance agencies of which the Cooperative is aware.
2. A third party previously designated by the Customer has been notified and has not made arrangements to pay the outstanding electric bill, provided that the Customer, or a third person designated by the Customer, uses his or her best efforts to obtain funds to pay the Cooperative's bills from various governmental or social assistance agencies which are known to them.
3. Arrangements or attempts to receive utility assistance must be made prior to the termination date on the bill. Payment guarantees from government or social assistance agencies must be received by the Cooperative via fax or e-mail prior to termination. Any balance not paid by the assistance or guaranteed payment, is the responsibility of the Customer and subject to termination in accordance with Section 355.

F. A Customer utilizing the provisions of D. or E. above may be required to enter into a deferred payment agreement with the Cooperative within 10 days after the scheduled termination date.

G. Disputed bills where the Customer has complied with the ACC's Rules on Customer bill disputes.

352. TERMINATION OF SERVICE WITHOUT NOTICE

Electrical service may be disconnected without advance written notice under the following conditions:

A. The existence of an obvious and imminent hazard to the safety or health of the Customer or the general population or the Cooperative's personnel or facilities.

B. The Cooperative has evidence of meter tampering, theft of service, or damage or loss to the Cooperative's property pertaining to the service to the Customer.

C. Failure of a Customer to comply with the curtailment procedures.

D. An emergency requiring immediate discontinuance of service.

E. Generator installations not approved by the Cooperative.

F. Customer failing to meet the terms of the deferred payment plan agreement.

353. RESTORATION OF SERVICE

The Cooperative shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Cooperative.

354. SERVICE TERMINATION WITHOUT NOTICE RECORD KEEPING

The Cooperative shall maintain a record of all terminations of service without notice. This record shall be maintained for a minimum of one year and shall be available for inspection by the ACC.

355. TERMINATION OF SERVICE WITH NOTICE

The Cooperative may disconnect service to any Customer for any reason stated below, as per the notice requirements set forth in these RRLEP.

A. Customer violation of any of the Cooperative Tariffs.

B. Failure of the Customer to pay a delinquent bill for electric service.

C. Failure to meet or maintain the Cooperative's deposit requirements.

D. Failure of the Customer to provide the Cooperative reasonable access to its equipment and property.

E. Customer breach of a written contract for service between the Cooperative and Customer.

F. When necessary for the Cooperative to comply with an order of any governmental agency having such jurisdiction.

G. When a hazard exists which is not imminent, but in the opinion of the Cooperative, it may cause personal injury or property damage.

H. When the service installation fails to meet Codes per Section 106. G.

I. Failure by the Customer to pay for damages, caused by the Customer, to the Cooperative's property or personnel.

J. Failure of the current occupant to transfer service into his/her name, if there is sufficient evidence that the current account holder is deceased.

356. SERVICE TERMINATION WITH NOTICE RECORD KEEPING

The Cooperative shall maintain a record of all terminations of service with notice. This record shall be maintained for one year and be available for ACC inspection.

357. TERMINATION NOTICE

The Cooperative shall not terminate electric service to any of its Customers without providing advance written notice to the Customer of its intent to disconnect service, except under those conditions specified where advance written notice is not required.

358. ADVANCE WRITTEN NOTICE INFORMATION REQUIRED

Such advance written notice shall contain, at a minimum, the following information:

A. The name of the person whose electric service is to be terminated and the address where service is being rendered

B. An explanation of the violation thereof or the amount of the bill which the Customer has failed to pay in accordance with the payment policy of the Cooperative, if applicable.

C. The date on or after which service may be terminated.

D. A statement advising the Customer to contact the Cooperative's office at 8600 West Tangerine Road and/or telephone for information regarding any deferred payment or other procedures which the Cooperative may offer or work out some other mutually agreeable solution to avoid termination of the Customer's electric service.

E. A statement advising the Customer that the Cooperative's stated reason for the termination of services may be disputed by contacting the Cooperative at 8600 West Tangerine Road, Marana, Arizona, and/or telephone advising the Cooperative of the dispute and making arrangements to discuss the cause for termination with a responsible representative of the Cooperative in advance of the scheduled date of termination. The responsible representative shall be empowered to resolve the dispute and the Cooperative shall retain the option to terminate service after affording this opportunity for a meeting and concluding that the reason for termination is just and advising the Customer of his right to file a complaint with the ACC.

359. THIRD PARTY NOTIFICATION

Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

360. TIMING OF TERMINATION WITH NOTICE

The Cooperative shall give at least five days advance written notice prior to the termination date.

361. DELIVERY OF NOTICE OF TERMINATION REQUIREMENT

Such notice shall be considered given to the Customer when a copy thereof is left with the Customer or posted first class in the United States mail, addressed to the Customer's last known address.

362. SERVICE TERMINATION DATE

If after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Cooperative for the payment thereof, or in the case of a violation of the Cooperative's RRLEP the Customer has not satisfied the Cooperative that such violation has ceased, the Cooperative may then terminate service on or after the day specified in the notice without giving further notice.

363. SERVICE TERMINATION BY COOPERATIVE

The service may only be disconnected by an authorized representative of the Cooperative, by a means acceptable to the Cooperative.

364. RETIREMENT OF FACILITIES

A. Retirement of facilities upon termination of service: The Cooperative shall have the right (but not the obligation) to remove any or all of its property (e.g. electric facilities) installed on the Customer's premises upon the termination of service. Customer's property (e.g. meter pedestal) attached to the Cooperatives property will be left on the Customer's premises unless other arrangements are made. If the Customer requests that electric facilities remain on Customer's premise they shall be obligated to pay monthly Customer charges or minimums in accordance with the applicable rate Tariff.

B. Retirement of idle facilities: Whenever service is idle for all or part of the time or is in an environment that requires higher than average operating costs the Cooperative shall have the right (but not the obligation) to remove any or all of its property (e.g. electric facilities) installed on the Customer's premises. The Cooperative will give proper notice of retirement of facilities as set forth for termination in Sections 360 and 361. If the Customer requests that electric facilities remain on Customer's premise they shall be obligated to pay monthly Customer charges or minimums in accordance with the applicable rate Tariff.

365. LANDLORD/TENANT RULE

In situations where service is rendered at an address different from the mailing address of the bill or where the Cooperative's Landlord/Tenant Agreement exists and that the landlord is the Customer of the Cooperative, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Cooperative will not disconnect service until the following actions have been taken:

A. Where it is feasible to provide service, the Cooperative, after providing notice as required in these RRLEP, shall offer the occupant the opportunity to subscribe for service in his or her own name. If the occupant then declines to subscribe, the Cooperative may disconnect service pursuant to the RRLEP.

B. The Cooperative will not attempt to recover from a tenant or condition service to a tenant with the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

C. If Trico terminates services to a tenant for non-payment by a tenant, and if a Landlord/Tenant Agreement exists, then the Cooperative will, upon request, reconnect at no charge to the Landlord's name – if the Landlord has no outstanding debts due to the Cooperative.

PART 4. ADMINISTRATIVE AND HEARING REQUIREMENTS

401. INVESTIGATION OF CUSTOMER SERVICE COMPLAINTS

The Cooperative shall make a full and prompt investigation of all service complaints made by its Customers.

402. RESPONSE TIME ON COMPLAINTS

The Cooperative shall respond to the complainant within five working days as to the status of the Cooperative's investigation of the complaint.

403. NOTIFICATION OF COMPLAINT INVESTIGATION FINDINGS

The Cooperative shall notify the complainant of the final disposition of each complaint. Upon request of the complainant, the Cooperative shall report the findings of its investigation in writing.

404. RIGHT OF APPEAL

The Cooperative shall inform the Customer of his right of appeal to the ACC.

405. RECORDING REQUIREMENTS OF COMPLAINTS

The Cooperative shall keep a record of all written service complaints received which shall contain, at a minimum, the following data:

A. Name and address of complainant

B. Date and nature of complaint

C. Disposition of the complaint

D. A copy of any correspondence between the Cooperative, the Customer, and/or the ACC.

This record shall be maintained for a minimum period of one year and shall be available for inspection by the ACC.

406. CUSTOMER BILL DISPUTES

Any Cooperative Customer who disputes a portion of a bill rendered for Cooperative service shall pay the undisputed portion of the bill and notify the Cooperative's designated representative that such unpaid amount is in dispute prior to the delinquent date of the bill.

407. COOPERATIVE'S RESPONSIBILITIES ON BILL DISPUTES

Upon receipt of the Customer notice of dispute, the Cooperative shall:

A. Notify the Customer within five working days of the receipt of a written dispute notice.

B. Initiate a prompt investigation as to the source of the dispute.

C. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results. Upon request of the Customer, the Cooperative shall report the results of the investigation in writing.

D. Inform the Customer of his right of appeal to the ACC.

408. CUSTOMER'S RESPONSIBILITY UPON INVESTIGATION COMPLETION

Once the Customer has received the results of the Cooperative's investigation the Customer shall submit payment within five working days to the Cooperative for any disputed amounts owed to the

Cooperative. Failure to make payment shall be grounds for termination of service as outlined in Section 355.

409. RESOLUTION OF SERVICE AND/OR BILL DISPUTES BY THE ARIZONA CORPORATION COMMISSION

A. In the event a Customer and the Cooperative cannot resolve a service and/or bill dispute, the Customer may file a written statement of dissatisfaction with the ACC; by submitting such notice to the ACC, the Customer shall be deemed to have filed an informal complaint against the Cooperative.

B. The Cooperative may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

C. The Cooperative shall maintain a record of written statements of dissatisfaction and their resolution for a minimum of one year and make such records available for ACC inspection.

"REDLINE"

Rules,
Regulations
&
Line
Extension
Policies

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Trico Electric Cooperative, Inc.
Rules, Regulations and Line Extension Policies
Effective Date: ~~August 6, 2009~~ ________________

~~TRICO ELECTRIC COOPERATIVE, INC.~~

~~Rules, Regulations and Line Extension Policies~~

~~PREFACE~~

~~Trico Electric Cooperative shall render electric service under these approved Rules and Regulations and extend its lines pursuant to this Line Extension Policy. Trico is committed to serve its Customers at rates that are approved by the Arizona Corporation Commission.~~

~~Upon the effective date of these Rules and Regulations and Line Extension Policies, all previously approved Rules and Regulations and Line Extension Policies are hereby cancelled and revoked, however, at the time this new Line Extension Policies is approved by the Arizona Corporation Commission all existing agreements, contracts, or cost letters with or to customers shall remain in effect per the term or time period stated in those agreements, contracts, or cost letters.~~

~~Any potential customer who has been given a line extension estimate or quote by Trico up to one year prior to an Order in this matter is automatically exempt from this line extension policy and shall be given the free footage for line extensions specified in Rules, Regulations, and Line Extension Policies on file with the Commission.~~

~~These Rules and Regulations and this Line Extension Policies shall apply in all cases except as modified by terms and conditions of rates or contracts approved by the Arizona Corporation Commission.~~

~~TRICO ELECTRIC COOPERATIVE~~
~~P.O. Box 930~~
~~8600 W. Tangerine Road~~
~~Marana, Arizona 85653-0930~~
~~Tel. (520) 744-2944~~
~~www.trico.coop~~

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DEFINITIONS

1. ABBREVIATIONS: Certain references, organizations and regulatory agencies have been abbreviated to acronyms throughout as a matter of convenience.

   ACC - Arizona Corporation Commission

   NEC - National Electrical Code

   NESC - National Electrical Safety Code

   NRUCFC (CFC) or CFC - National Rural Utilities Cooperative Finance Corporation

   RRLEP – These Rules, Regulations & Line Extension Policies

   RUS - Rural Utilities Service

2. ADVANCE IN AID OF CONSTRUCTION (ADVANCE): Funds provided to the Cooperative by the Applicant under the terms of a line extension agreement the value of which may be refundable.

3. AGREEMENT: Synonymous with "Contract" as used herein.

4. APPLICANT: Any person, firm, agent, organization, corporation or governmental body applying for electric service from the Cooperative.

5. APPLICATION: A request to the Cooperative for electric service, as distinguished from an inquiry as to the availability or charges for such service.

6. ARIZONA CORPORATION COMMISSION: The regulatory authority of the State of Arizona having jurisdiction over Trico Electric Cooperative, Inc., abbreviated as "ACC" in these RRLEP.

6. AUTOMATIC METER READING (AMR): Automatic Meter Reading (AMR) is the remote collection of consumption data from Customers' utility meters using telephony, radio frequency, power-line and satellite communications technologies.

7. BILLING DEPOSITS: As ~~the word is~~ used in Sections ~~124~~119 through ~~131~~126 of these RRLEP, it shall be deemed to mean deposits made by Customers as a guaranty of the payment of the bills for electric service rendered by the Cooperative.

8. BILLING MONTH: The period between any two ~~(2)~~ regular readings of the Cooperative's meters at approximately ~~thirty (30)~~ day intervals.

9. BILLING PERIOD: The time interval between two ~~(2)~~ consecutive meter readings that are taken for billing purposes.

10. CODES: Applicable electric Codes may be the NEC the NESC any Rule or Regulation adopted by RUS, or by a City, Town, County and/or State authority. Any such permitting, clearance requirements or specification the Cooperative deems necessary and or prudent in accordance with sound engineering practices and safety guidelines.

~~10~~11. CONNECTED LOAD: Total of the ~~name plate~~nameplate ratings or measured load of the electrical equipment connected to the electrical installation or system.

12. CONTRIBUTION IN AID OF CONSTRUCTION (CONTRIBUTION): Funds provided to the Cooperative by the Applicant under the terms of a line extension agreement or service connection Tariff, none of which is refundable.

13. COOPERATIVE: Trico Electric Cooperative, Inc.

~~11~~14. COOPERATIVE EQUIPMENT: The service lines, meter installations, structures, devices, apparatus, hardware and other facilities installed by or on behalf of, and/or owned by, the Cooperative and/or other transmission and distribution facilities of the Cooperative's system.

15. COOPERATIVE'S SPECIFICATIONS: Established standards and requirements supplied to Customers to obtain, construct, or maintain their electric service equipment, in accordance with applicable Codes, sound engineering, construction and financial practices.

16. CUSTOMER: The person or entity in whose name service is rendered, as evidenced by the signature on the application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service.

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~~12~~17. CUSTOMER CHARGE: The amount the Customer must pay the Cooperative for the availability of electric service, excluding any electricity used, as specified in the Cooperative's ~~tariffs~~Tariffs.

~~13~~18. CUSTOMER'S SERVICE ENTRANCE: In general, all conductors, devices, apparatus, and hardware on the Customer's side of the ~~point~~Point of ~~delivery~~Delivery, except the Cooperative's meter installation.

~~14. CODES: Applicable electric Codes may be the NEC the NESC any Rule or Regulation adopted by RUS, or by a City, Town, County and/or State authority. Any such permitting, clearance requirements or specification the Cooperative deems necessary and or prudent in accordance with sound engineering practices and safety guidelines.~~

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~~16. COOPERATIVE: Trico Electric Cooperative, Inc.~~

~~17. COOPERATIVE EQUIPMENT: The service lines, meter installations, structures, devices, apparatus, hardware and other facilities installed by or on behalf of, and/or owned by, the Cooperative and/or other transmission and distribution facilities of the Cooperative's system.~~

~~18~~19. DAY: Calendar day.

~~19~~20. DEMAND: The rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. ~~The period of time, unless otherwise specified in the rate tariff or contract or otherwise provided for, will be fifteen (15) minutes.~~

~~20~~21. DEVELOPER: Any ~~person, firm~~individual, partnership, corporation, ~~organization or~~ governmental ~~body~~agency, or other organization, funding and/or developing lots or parcels of land for use, sale or lease, either improved or unimproved with real property improvements on such lots or parcels.

~~21~~22. DISTRIBUTION LINES: Any of the Cooperative's power system lines operated at distribution voltages below 69 kV.

~~22~~23. EFFECTIVE DATE: The effective date of these ~~Rules and Regulations and Line Extension Policy shall be the date that the same are~~RRLEP, as approved by the ACC.

~~23~~24. ELECTRICAL SERVICE: The availability of electric energy, metered or otherwise, available to the Customer within established standards of voltage and frequency to the ~~point~~Point of ~~delivery~~Delivery.

~~24~~25. ELDERLY: A person who is 62 years of age or older.

26. ENERGY: Electrical energy, ~~the usage of which is measured~~expressed in kilowatt-hours (kWh).

~~27~~25. ~~FACILITIES CHARGE: A monthly or one time charge by Trico to a primary metered customer for the cost associated with: (i) the design, construction, and maintenance of all electric distribution facilities installed by Trico beyond the point of delivery (load side of the meter) dedicated solely to the Customer, which the Customer has agreed Trico shall design, construct, own, and maintain on behalf of the Customer; or (ii) the maintenance for such distribution facilities installed beyond the delivery point, that the Customer shall fund and construct according to RUS and NESC standards of construction and which Trico has agreed to maintain on behalf of the Customer.~~

~~26~~. HANDICAPPED: A person with a medically diagnosed physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out activities of daily living or protect oneself from neglect or hazardous situations without assistance from others.

~~27~~28. ILLNESS: A medical ailment or sickness for which a residential Customer obtains a verifiable document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

~~28~~29. INABILITY TO PAY: Circumstances where a residential Customer:

A. Is not gainfully employed and unable to pay~~,~~; or

B. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that ~~he~~the Customer receives his bill and can obtain verification of that fact from the government welfare assistance agency~~,~~; and

C. Has an annual income below the published federal poverty level and can produce evidence of this~~,~~; and

D. Signs a declaration verifying that the Customer meets one ~~(1)~~ of the above criteria and is either ~~elderly, handicapped~~Elderly, Handicapped, or suffers from ~~illness~~Illness.

~~29~~30. INTERRUPTIBLE ELECTRIC SERVICE: Electric service that is subject to interruption as specified in the Cooperative's ~~tariff~~Tariff.

~~30~~31. KILOWATT (kW): A unit of power equal to 1,000 watts.

~~31~~32. KILOWATT HOUR (kWh): ~~The~~Electric energy equivalent to the amount of electric energy delivered in one ~~(1)~~ hour~~,~~ when delivery is at a constant rate of ~~one~~ (1) kilowatt.

~~32~~33. LINE EXTENSION: The lines and equipment necessary to extend the electric distribution system of the Cooperative to provide service to one ~~(1)~~ or more additional Customers.

~~33~~34. MASTER METER: A meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

~~34~~35. MEMBER: Any Member of the public, including person, firm, association, corporation and bodies politic or subdivision thereof, who has qualified for Membership as provided for in the By-Laws of the Cooperative.

~~35~~36. METER: The instrument for measuring and indicating ~~and~~/or recording the flow of electricity that has passed through it.

~~36~~37. METER INSTALLATION: The meter(s) and auxiliary devices and hardware, if any, constituting the Cooperative's equipment needed to measure energy use and/or billing demand supplied to the Customer.

~~37~~38. METER TAMPERING: Any situation where a meter or associated devices and wiring has been illegally altered. ~~Some common~~Common examples are but are not limited to; meter bypassing, use of magnets to slow the meter recording, and broken meter seals.

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~~38~~39. MINIMUM CHARGE: The amount the Customer must pay for the availability of electric service, including an amount of usage, as specified in the Cooperative's ~~tariffs~~Tariffs.

~~39~~40. NEW ~~CONSTRUCTION~~SERVICE ESTABLISHMENT FEE: A charge as specified in the Cooperative's ~~tariffs~~Tariffs for service requiring new construction.

~~40~~41. PERMANENT SERVICE: Electric service, which in the opinion of the Cooperative, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature.

~~41~~42. PERSON: Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

~~42~~43. POINT OF DELIVERY: The point where facilities (whether owned, leased, or under license by a customer ~~connects~~) connect to the Cooperative's facilities, as denoted in ~~their~~ the Cooperative's electric service specifications or by written agreement.

~~43~~44. POWER: The rate of generating, transferring ~~and/~~or using electric energy, usually expressed in kilowatts.

~~44~~45. PREMISES: All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.

~~45~~46. PROPER NOTICE: Unless specified otherwise, a written message delivered by first class mail, via email, or in person by one party to the other at the recipient's last known address, the period of notice commencing from the date of ~~personal~~email delivery or mailing.

~~46~~47. REGULAR HOURS: The hours 8:00 a.m. to 4:30 p.m. Monday through Friday shall be considered regular hours, except for Cooperative holidays. However, service hours may be worked at hours different from those listed as regular hours.

~~47~~48. RESIDENTIAL USE: Service to Customers using electricity for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, residential water well and other residential uses and includes use in apartment buildings, mobile home parks, and other multiunit residential buildings.

~~48. RULES: These Rules and Regulations and Line Extension Policies.~~

49. SERVICE AREA: The territory in which the Cooperative has been granted a Certificate of Convenience and Necessity (CC&N) and is authorized by the law to provide electric service.

50. SERVICE AVAILABILITY CHARGE: A charge for the purpose of maintaining adequate revenue to cover the operating costs of an extension of line whenever service is idle for all or part of the time or is in an environment that requires higher than average operating costs.

51. SERVICE CONNECTION/DISCONNECTION: The attachment/detachment of electric service by an authorized representative of the Cooperative including operation of Customer owned disconnect devices, if appropriate for safety reasons.

52. SERVICE ESTABLISHMENT: The establishment of electric service to the Customer when the Customer's facilities are ready and acceptable to the Cooperative and the Cooperative needs only to install or read a meter or turn the service on.

53. SERVICE LINE: The line extending from a distribution line or transformer to the Customer's premises or ~~point~~Point of ~~delivery~~Delivery.

54. SERVICE RECONNECT CHARGE: The charge as specified in the Cooperative's ~~tariffs~~Tariffs which must be paid by the Customer prior to reestablishment of electric service each time the electricity is disconnected for nonpayment or whenever service is discontinued for failure otherwise to comply with the Cooperative's ~~tariffs~~Tariffs, or these ~~Rules~~RRLEP.

55. SERVICE REESTABLISHMENT CHARGE: A charge as specified in the Cooperative's ~~tariffs~~Tariffs for service at the same location where service disconnection was made for the same Customer.

56. SINGLE FAMILY DWELLING: A house, an apartment, a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as a permanent home.

57. SPINE FACILITIES OR BACKBONE FACILITIES: A large capacity electric distribution system generally not directly connected to individual lots and designed, sized, and constructed to provide adequate service of the proper phase and voltage to the boundary of blocks or large parcels within an approved Master ~~Planed~~Planned Development in which such blocks or parcels are intended to be subdivided in the future into platted blocks or subdivisions for residential and commercial uses; or the large capacity electric distribution system required to serve an area comprised of a large subdivision or several subdivisions or ~~may~~many platted subdivisions which are not part of a Master Planned Development but which by their proximity to each other and by their zoned uses are similar in nature to a Master Planned Development, and in this event such spine system may be adjacent to individual lots.

58. TARIFFS: The documents filed with the ~~Commission~~ACC which list the services and products offered by the Cooperative and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products.

59. TEMPORARY SERVICE: Service to premises or enterprises which are temporary in character, or where it is known in advance that the service will be of limited duration. Service which, in the opinion of the Cooperative, is for operations of a speculative character is also considered temporary service and will be required to make an advance for the cost of retiring the service .

60. TERRITORIAL EXTENT: ~~These Rules and Regulations and Line Extension Policies~~The RRLEP will be effective and apply throughout the Service Area of the Cooperative by an order or orders of the ACC or by judgment of the courts of Arizona, or by the specific orders of approved rate ~~tariffs~~Tariffs of the ACC, in which such event modifications shall govern where applicable.

61. THIRD PARTY NOTIFICATION: A notice sent to an individual or a public entity willing to receive notification of the pending discontinuance of service of a Customer of record in order to make arrangements on behalf of said Customer satisfactory to the Cooperative.

62. TRICO: Trico Electric Cooperative, Inc.

~~63~~63. ~~COOPERATIVE'S SPECIFICATIONS: Established standards and requirements supplied to Customers to obtain, construct, or maintain their electric service equipment, in accordance with applicable Codes, sound engineering, construction and financial practices.~~

~~6~~4. WEATHER ESPECIALLY DANGEROUS TO HEALTH: That period of time commencing with the scheduled termination date when the local weather forecast, as predicted by the National Oceanographic and Administration Service, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast. The ~~Commission~~ACC may determine that other weather conditions are especially dangerous to health as the need arises.

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PART 1.
APPLICATION FOR ELECTRIC SERVICE

101. APPLYING FOR ELECTRIC SERVICE

Trico may require a new Applicant for service to appear at Trico's offices at 8600 W. Tangerine Rd., Marana, Arizona, to produce proof of identity and sign the appropriate application form or contract before service is supplied by Trico.

102. APPLICATION FOR SERVICE

~~1.~~A. The application for service form may require, but not necessarily be limited to, the following information:

- ~~A~~1. Name or names of Applicant(s).
- ~~B~~2. Service address or location and telephone number.
- ~~C~~3. Billing address/telephone number if different ~~than~~from service address.
- ~~D~~4. Address where service was previously provided~~.~~ and email address (when available)
- ~~E~~5. Date Applicant will be ready for service.
- ~~F~~6. Statement as to whether premises have been previously supplied with electric service, and if so, date service was discontinued and the reason therefore.
- ~~G~~7. Purpose for which service is used.
- ~~H~~8. Statement as to whether Applicant is owner, tenant or agent for the premises. For tenants, a copy of the signed rental agreement and contact information for owner.
- ~~I~~9. Information concerning the energy and demand requirements of the Customer.
- ~~J~~10. Type and kind of life support equipment used, ~~if any,~~ or to be used, by the Customer.
- ~~K~~11. Applicant's social security number ~~(optional).~~or driver's license number.
- ~~L~~12. Applicant's verification of legal age.
- ~~M~~13. Name, phone number, relationship and address of Applicant's closest living relative not living in the home.

~~2.~~B. Customer specific information shall not be released without specific prior written authorization unless the information is requested by law enforcement or other public agency, or is requested by the ~~Commission~~ACC or its Staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer.

~~3.~~C. Where service is requested by two ~~(2)~~ or more individuals at the same location, Trico has the right to collect the full amount owed from any one ~~(1)~~ of the Applicants.

~~4.~~D. In the absence of a signed application or contract for service, the supplying of electric service by the Cooperative and the acceptance thereof by the Customer shall be deemed to constitute an agreement by and between the Cooperative and Customer for furnishing and receiving electric service under the Cooperative's applicable rates, minimums and provisions for making electric service available.

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103. DOUBTFUL PERMANENCY

~~When~~If, in the Cooperative's opinion, the~~ permanent~~ nature of the Customer's requirement for electric service is doubtful~~,~~ as to whether it constitutes Permanent Service, then the Customer ~~shall be required to~~must enter into a contract with the Cooperative and pay the entire cost of construction, including ~~the~~any necessary equipment to serve the Customer (e.g., transformers and associated structures~~ and~~), as well as the cost of retirement of facilities to be installed for the ~~Customer. See Definition~~purposes of ~~Permanent Service.~~providing service to the Customer.. The contract shall include provisions that when the permanent nature of the service has been established to the satisfaction of the Cooperative, the ~~Rules~~RRLEP that pertain to Permanent Service shall be applicable.

104. EXTENSION OF LINE REQUIRED

When an extension of the Cooperative's electric lines is requested, the Cooperative shall advise the Applicant(s) of the provisions of the line extension policies in Sections 201-~~227~~217, including the costs associated with the proposed line extension. Provisions of the line extension policy are limited to services applicable in the Cooperative's approved ~~tariffs~~Tariffs, utility grade quality of power, and construction is limited to the Cooperative's construction standards. Provisions of the line extension policy are limited to the Cooperative's established alternating nominal distribution voltages -14.4/24.9 kV, Y-Y transformation and construction limited to the Cooperative's construction standards. Other distribution voltages and transmission voltages may be provided on case-by-case basis. The Cooperative has established alternating nominal transmission voltage of 69kV or 115kV that are available in many areas of the Cooperative's system.

105. SERVICE BEYOND SCOPE OF LINE EXTENSION POLICY

When the service requested is different from the standard conditions as noted in Section 104 and elsewhere in this policy, service may be extended to the Applicant(s) under a separate contractual agreement which -shall be filed with the ~~Arizona Corporation Commission~~ACC.

106. CONDITION FOR SUPPLYING SERVICE

The Cooperative reserves the right to determine the conditions under which an extension will be granted. Conditions for service and extending service to the Customer will be based upon the following:

A. Customer has wired his premises in accordance with the applicable Codes.

B. Customer has installed the electric service entrance equipment in a suitable location and with suitable protection so that the loss of power or the partial loss of voltage, or phases does not damage the Customer's facilities, electric system, and or appliances.

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~~C. In the case of a mobile home the overhead meter panel shall be attached to a meter pole or to an approved support or an acceptable underground meter panel provided by the mobile home manufacturer.~~

~~D~~C. In case of temporary construction service, the electric service entrance equipment shall conform to 106.A and 106.E.

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~~E~~D. All such installations shall be in accordance with the Cooperative's specifications and located at an outdoor location accessible to the Cooperative.

~~F~~E. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper rights-of-way locations.

~~G~~F. Developers shall have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

~~H~~G. The Customer agrees to have his installation comply and continue to maintain compliance with the applicable Codes. The Customer will also provide, at their own expense all permitting, licensing, clearances and processes and periodic inspections under their control for which they are responsible, prior to the service being connected.

~~I~~H. The Customer will be responsible for the electric bills of all services.

~~J~~I. Customer agrees that failure to maintain compliance with the Codes is cause for disconnection of the service. Code compliance is required before service will be restored.

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~~K~~J. A reduced starter acceptable to the Cooperative shall be installed by the Customer for all 200 HP motors and above and may be required by the Cooperative for motors 40 HP and above.

107. IDENTIFICATION OF LOAD AND PREMISES

The premises and electric load to be served by the Cooperative shall be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Cooperative shall be required to act upon a request for electric service. Existing electric with multiple services at the premises may require that the Customer provide the Cooperative's meter number for the service they wish to connect.

108. IDENTIFICATION OF RESPONSIBLE PARTY

The identity of the party(ies) responsible for accounts in the name of any Customer shall be established in a manner acceptable to the Cooperative. Any person applying for service to be connected in the name of or in care of another Customer shall furnish to the Cooperative acceptable written approval from that Customer guaranteeing payment of all bills under the account. Application for service by a minor shall be subject to written assurance of a party responsible for such service as required by the Cooperative. The Customer is responsible in all cases for service supplied to the premises until the Cooperative has received proper notice of the effective date of termination or transfer of service. The Customer shall also promptly notify the Cooperative of any change in billing address.

109. ASSIGNMENT OF RATE TARIFF

The Cooperative shall use its best efforts to assign the appropriate rate ~~tariff~~Tariff for the customer's service based on the available data at the time of the service application. The Cooperative shall use its best efforts to notify the Customer of the applicable rate ~~tariff~~Tariff if the Customer's service classification has changed after initial application, and shall not be required to refund the difference in charge under different rate ~~tariffs~~Tariffs. Upon written notification of any material changes in the Customer installation or load conditions, the Cooperative will assist in determining if a change in rate ~~tariff~~Tariff is desirable, but not more than one ~~(1)~~ such change at the Customer's request may be made within any ~~twelve (~~12~~)~~-month period.

110. TAMPERING WITH OR DAMAGING COOPERATIVE EQUIPMENT

The Customer agrees, when accepting service, that no one except authorized Trico representatives shall be allowed to remove or replace any Cooperative equipment installed on the Customer's property. The Customer will be held responsible for any broken seals, tampering, or interfering with the Cooperative's meter(s), equipment, or property installed on the Customer's premises. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or Customer's wrongful act or omission on the part of any of the Customer's agents, employees, licensees, or contractors. ~~The Customer should be aware that under~~

~~the Arizona Revised Statute §13-1602 it is a felony to tamper with the property of a utility.~~The Cooperative also has the right to refer any matter regarding tampering to the appropriate law enforcement authorities as a criminal matter, including for criminal damage to utility equipment.

111. GROUNDS FOR REFUSAL OF SERVICE

The Cooperative may refuse to establish service if any of the following conditions exist:

A. The Applicant is indebted to the Cooperative and the Applicant has not paid the outstanding balance and fees in full.

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B. A condition exists which in the Cooperative's judgment is unsafe or hazardous to the Applicant, the general population, or the Cooperative's personnel or facilities.

C. ~~Refusal by the~~ Applicant refuses to provide the Cooperative with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements.

D. Customer is known to be in violation of any of the Cooperative's ~~tariffs~~Tariffs filed with the ~~Commission~~ACC.

E. Failure of the Customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer, and which ~~have been specified by~~ the Cooperative ~~as a condition for~~has conditioned providing service upon.

F. Applicant falsifies or misrepresents his or her identity for the purpose of obtaining service.

G. Applicant is in violation of these ~~Rules~~RRLEP or any applicable Rule or regulation of the ACC or any applicable law, or is in default as to any prior agreement between the Applicant and the Cooperative.

H. Customer has failed to comply with the Codes or permitting/~~clearance~~inspection requirements.

112. SCHEDULING OF SERVICE ESTABLISHMENT

After an Applicant has complied with the Cooperative's application and deposit requirement, the requirements of Sections 104-106, and has been accepted for service by the Cooperative, the Cooperative shall schedule that Customer for service establishment.

113. SERVICE ESTABLISHMENT EXCEPTION

Service establishments shall be scheduled for completion within five ~~(5)~~ working days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five ~~(5)~~ working day limitation.

~~**114. SERVICE ESTABLISHMENT APPOINTMENTS**~~

~~When the Cooperative has arranged to meet with a Customer for service establishment purposes and the Cooperative or the Customer cannot make the appointment during the prearranged time, the Cooperative shall reschedule the service establishment to the satisfaction of both parties.~~

~~**115. SCHEDULING OF APPOINTMENTS**~~

~~The Cooperative shall schedule service establishment appointments within a maximum of four (4) hours during normal working hours, unless another time frame is mutually acceptable to the Cooperative and the Customer.~~

~~116~~114. SERVICE ESTABLISHMENT BY THE COOPERATIVE

Service establishment shall be made only by a qualified Cooperative service representative or its agent or contractor.

~~**117. RESERVED FOR FUTURE ADDITIONS**~~

~~118. RESERVED FOR FUTURE ADDITIONS~~

~~119~~115. TEMPORARY SERVICE PAYMENT REQUIREMENTS

Applicants for ~~temporary service~~Temporary Service may be required to pay the Cooperative in advance of service establishment, a contribution in aid of construction, based on the estimated cost of installing and removing the facilities, less any salvage, necessary for furnishing the desired service. Temporary ~~service~~Service must meet ~~or exceed~~ the requirements of ~~the~~any and all applicable Codes ~~(see Definition 12).~~as defined in these RRLEP.

~~120~~116. TEMPORARY SERVICE - LESS THAN ONE MONTH

Where the duration of service is to be less than one ~~(1)~~ month and the Applicant does not have any outstanding debts to the Cooperative, the Applicant may also be required to advance a sum of money equal to the estimated bill for service and a service establishment fee in lieu of a minimum-security deposit.

~~121~~117. TEMPORARY SERVICE - MORE THAN ONE MONTH

Where the duration of service is to exceed one ~~(1)~~ month, the Applicant may also be required to meet the deposit requirements of the Cooperative.

~~122~~118. CHANGE OF CLASSIFICATION

If at any time during the term of the agreement for temporary services the character of a temporary Customer's operations change so that in the opinion of the Cooperative, the Customer is classified as permanent, the terms of the Cooperative's ~~line extension Rules shall~~RRLEP applicable to Line Extensions will apply. Cost of retirement advance shall be refunded to the Customer once the service is no longer classified as temporary.

119~~123.~~ ~~RESERVED FOR FUTURE ADDITIONS~~

~~124.~~ BILLING DEPOSIT REQUIREMENTS

~~A.~~ The Cooperative will not require a deposit from an Applicant for service if the Applicant is able to meet any of the requirements ~~of 1 or 2~~ below:

1. The Applicant has ~~had~~existing service with the Cooperative of a comparable nature ~~with the Cooperative within the past two (2) years and~~, was ~~neither~~not delinquent in payment (including returned payments) more than twice during the last ~~twelve (~~12~~)~~ consecutive months ~~of service nor was~~, has not been disconnected for non-payment, nor had more than two insufficient funds checks, e-checks, credit card or other electronic payments declined.
2. The Applicant can produce a letter ~~regarding~~of credit ~~or verification~~ from ~~an~~a current electric utility receiving service for a minimum of ~~a comparable nature within~~ the past two ~~(2)~~ years; and was neither delinquent in payment more than twice during the last ~~twelve (~~12~~)~~ consecutive months of service nor was disconnected for non-payment.

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~~125~~120. BILLING DEPOSIT RECEIPT

The Cooperative may issue a nonnegotiable receipt to the Applicant for the billing deposit. The inability of the Customer to produce such a receipt shall in no way impair his right to receive a refund of the billing deposit, ~~which~~if it is reflected on the Cooperative's records.

~~126~~121. INTEREST ON BILLING DEPOSITS

Billing Deposits shall be interest bearing; the interest rate and method of calculation is defined in the Schedule of Special Charges, Interest on Billing Deposits clause.

~~127~~122. BILLING DEPOSIT REFUND

Billing deposits will automatically be refunded by applying the billing deposit and accrued interest to the account by the Cooperative after ~~twelve (~~12~~)~~ consecutive months, during which time the Customer has not been delinquent more than two ~~(2)~~ times in a ~~twelve (~~12~~)~~-month period, or at the discretion of the Cooperative at any time before service is discontinued. Upon discontinuance of service, the Cooperative shall have a reasonable time, but not less than three ~~(3)~~ working days (Monday through Friday excluding holidays) in which to read and remove its meters and to ascertain that the obligations of the Customer have been duly performed before being required to return a billing deposit. Upon final discontinuance of the use of the service and full settlement of all bills by the Customer, any billing deposit, not previously refunded, with accrued interest, (if any), in accordance with the provisions of this policy will be returned to the Customer or at the Cooperative election, it may be applied to the payment of any unpaid accounts of the Customer and the balance, (if any), returned to the Customer. Deposits paid due to tampering will be held for a minimum of two years or applied to the final bill, if service is terminated before the end of the two-year minimum.

Upon written request, an existing deposit may be transferred to another account holder if the deposit is eligible for refund or if a vacating customer wishes to transfer his/her deposit to the new tenant and the final bill has been paid in full.

123. ~~128.~~ ~~AMOUNT OF~~ BILLING DEPOSIT AMOUNT

The amount of a billing deposit required by the Cooperative shall be determined according to the following terms:

A. Residential Customer billing deposits may be equal to no more than two ~~(2)~~ times that of the Customer or customer class, estimated average monthly bill.

B. Non-residential Customer billing deposits may be equal to no more than two and one-half ~~(2-1/2)~~ times that of the Customer's estimated average monthly bill.

~~129~~124. BILLING DEPOSIT ADJUSTMENT

A. The Cooperative may review the Customer's usage after service has been connected and adjust the billing deposit amount based upon the Customer's actual usage.

B. The Cooperative may require a residential Customer to establish or reestablish a billing deposit if the Customer has become delinquent in the payment of two ~~(2)~~ monthly bills within a 12-consecutive month period or has been disconnected for service during the last 12 months.

~~130~~125. BILLING DEPOSIT PER METER

A separate billing deposit may be required for each meter installed.

~~131~~126. BILLING DEPOSITS AND SERVICE SUSPENSION

Customer billing deposits shall not prevent the Cooperative from terminating the agreement for service with a Customer, or suspending service for any failure in the performance of Customer obligations under the agreement for service, or any violation of the Cooperative's ~~Rules and Regulations~~RRLEP in effect from time to time as approved by the ~~Arizona Corporation Commission~~ACC.

~~132. MEMBERSHIP~~

~~All Customers will be Members of the Cooperative by receiving electrical service from the Cooperative unless the Cooperative is otherwise notified in writing by the Customer that the Customer elects not to become a Member.~~

~~133. RESERVED FOR FUTURE ADDITIONS~~

~~134~~127. OBLIGATIONS OF MEMBER

In addition to the provisions of these ~~Rules~~RRLEP and the Cooperative's ~~tariffs~~Tariffs, each Member shall be bound by the Articles of Incorporation and By-Laws of the Cooperative, as the same may be amended from time to time. Customers who elect not to become a Member shall be bound by these ~~Rules~~RRLEP and the Cooperative's ~~tariffs~~Tariffs.

~~**135. RESERVED FOR FUTURE ADDITIONS**~~

~~136~~128. MEMBERSHIP LIMIT

No Customer may hold more than one membership and a ~~personal~~ membership may be held jointly by ~~both husband and wife~~a legally married couple pursuant to the provisions of the By-Laws of the Cooperative.

~~137~~129. RESPONSIBILITY OF THE COOPERATIVE

~~Prompt, reliable electric service to the Customer is the Cooperative's primary objective. In general, there is no charge to the Customer for service calls related to voltage problems, malfunctions of the Cooperative's equipment and other areas where the Cooperative is responsible.~~ The Cooperative shall use reasonable diligence to ~~supply~~provide or continue to ~~supply~~provide electric service~~,~~; but if in the event service fails, is interrupted, curtailed, becomes defective~~,~~ or becomes unlawful to provide, ~~or through~~ due to any cause that is beyond the reasonable control of the Cooperative (including from acts of God or ~~by~~ the public enemy, ~~or by~~ accidents, strikes, labor troubles or by action of the elements, ~~or by~~ the inability to secure rights-of-way, governmental permits, or certificates, franchises or licenses~~, or for any other cause beyond the reasonable control of~~) then the Cooperative~~, it shall~~ will not be liable ~~therefor.~~for any inability to provide such service. The Cooperative shall also not be liable to the Customer or any other person for damages resulting from failures, interruptions or defects of service or any consequential damages sustained by the Customer ~~by reason of~~or person due to any such failure, interruption or defect of service.

~~**138. RESERVED FOR FUTURE ADDITIONS**~~

~~139~~130. RATE TARIFFS

The Cooperative shall make available, upon Customer request, ~~a copy of~~ the rate ~~tariff~~Tariff pursuant to which the Customer receives electric service from the Cooperative.

~~140~~131. TARIFFS~~, RULES~~ AND ~~REGULATIONS~~RRLEP

~~In addition, the~~The Cooperative shall make available upon Customer request a ~~concise~~ summary of the Cooperative's ~~tariffs~~Tariffs or the Cooperative's ~~Rules and Regulations~~RRLEP concerning:

A. Billing Deposits

B. Termination of service

C. Billing and collection

D. Complaint handling

~~141~~These RRLEP will be effective and apply throughout the Service Area of the Cooperative by an order or orders of the ACC or by judgment of the courts of Arizona, or by the specific orders of approved rate Tariffs of the ACC, in which such event modifications shall govern where applicable.

132. RECORD OF CONSUMPTION

The Cooperative upon request of a Customer shall ~~transmit~~provide a statement of actual consumption by such Customer for each billing period during the prior ~~twelve (~~12~~)~~ months unless such data is not reasonably attainable.

~~142~~133. CUSTOMER RIGHTS

The Cooperative shall inform all new Customers of their right to obtain the information specified in Section ~~139, 140~~130, 131 and ~~141~~132.

~~143~~134. RESPONSIBILITY OF THE CUSTOMER

The Customer, in addition to the other responsibilities set forth in these ~~Rules~~RRLEP, shall be responsible for:

A. Use of electric service.

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B. The repair or maintenance of Customer-owned equipment beyond the ~~point~~Point of ~~delivery~~Delivery, including any condition that adversely affects the Cooperative's service to the Customer or to others.

C. Prompt notification to the Cooperative by the fastest available means of outages.

D. Prompt notification to the Cooperative of any material changes in the Customer's installation or load conditions.

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E. Prompt notification to the Cooperative of any other conditions in the Customer's electric service resulting in substandard or irregular electric service.

F. The Customer shall provide all utility easements and access as required under ~~Rule 155~~Section 145 at no cost to the cooperative.

~~144~~135. SERVICE CALL FEES

In general, there is no charge to the Customer for service calls related to voltage problems, malfunctions of the Cooperative's equipment and other areas where the Cooperative is responsible. The Cooperative may charge a fee for the services defined below in accordance with the applicable Tariffs of the Cooperative. The amount of the service fee will be determined by the type of personnel needed and whether the work is performed during working or nonworking hours. Reasonable efforts will be made to advise the Customer about appropriate service call fees before the service call begins. Some examples of these service calls are (but are not limited to) the following:

A. Each Customer may be charged a fee for the ~~service establishment~~Service Establishment, reestablishment, or reconnection of utility services, including transfers of service or return trips in the event the initial trip was unsuccessful due to the fault of the Customer. The ~~service establishment~~Service Establishment fee shall entitle the Customer to one service connection. The ~~service establishment~~Service Establishment fee ~~shall be~~is non-refundable, non-transferable and ~~shall~~does not apply against a final or any other bill rendered by the Cooperative to the Customer.

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B. A response to a power interruption call where it is determined that the Customer's equipment is at fault and there is electricity at the ~~point~~Point of ~~delivery~~Delivery.

C. An interruption caused by the Customer's willful act or omission, negligence or failure of Customer-owned equipment, even though the Cooperative is unable to perform any work beyond the ~~point~~Point of ~~delivery~~Delivery.

D. The Customer's service was previously disconnected for non-payment, unlawful use of service, misrepresentation to the Cooperative, unsafe conditions, threats to Cooperative personnel or property, failure to permit access, detrimental effects of Customer loads on the Cooperative system, failure to establish credit and/or sign an agreement for service, or any other reason authorizing the Cooperative to make such disconnection.

~~E. The Customer requests that the Cooperative pick up bill payment at the electric service location in lieu of other methods of payment, if acceptable to the Cooperative.~~

~~F~~E. A reestablishment of electric service to be reconnected when the same Customer who requested the service to be disconnected, remains a resident at the same premises.

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~~G~~F. A return trip to the same premises when the Customer fails to comply with the Cooperative's conditions for supplying service or fails to supply access to the premises for the initial trip.

~~H. A return trip to the same premises when the Member fails to have funds available for service reconnect previously disconnected for non-payment.~~

~~145~~136. SERVICE INTERRUPTION

The Cooperative may temporarily suspend service to make repairs, replacements, maintenance, tests or inspections of Cooperative equipment or to make tests, inspections, connections or disconnections of Cooperative service. The Cooperative shall make reasonable efforts to notify the Customer about the need for and the duration of a planned service interruption, but it may suspend service in an emergency situation without prior notice to the Customer.

~~146. RESERVED FOR FUTURE ADDITIONS~~

~~147~~137. DAMAGES TO THE COOPERATIVE

In the event any of the causes of interruptions set forth in Section ~~144~~135 or any negligence by the Customer or Customer's electric service cause damage to the Cooperative's property or personnel or the ability of the Cooperative to provide service to others, the responsible party shall be fully liable to the Cooperative therefor and the service charges set forth in such Sections shall not affect the right to recover the amount of such damages.

~~148~~138. SERVICE CHARGES DUE

The service charges and damages referred to in ~~Section 144and 147~~Sections 135 and 137 shall be added to the Customer's monthly bill and be subject to collections and termination~~, except that service~~. The Customer must pay all charges for reconnection of any service disconnected for non-payment ~~may be required to be paid~~ prior to reconnection.

~~149~~139. MOBILE HOME PARKS

A. The Cooperative shall have the right to refuse service to all new construction of and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is ~~individually~~ metered to each unit by the Cooperative. This includes the Cooperative having the right to refuse any Master Meter arrangement for the expansion of such existing parks. Line extensions and service connections to serve such expansion shall be governed by the Line Extension and Service Connection Policy of the Cooperative.

B. Permanent residential mobile home parks for the purpose of this Section shall mean mobile home parks where, in the opinion of the Cooperative, the average length of stay for an occupant is a minimum of six months.

C. For the purposes of this Section, expansion means the addition of permanent residential spaces in excess of that existing at the effective date of this ~~Rule~~Section.

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~~150~~140. RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS, AND OTHER MULTI-UNIT RESIDENTIAL BUILDINGS

A. Trico will not allow any Master ~~metering shall not be allowed~~Meter arrangement for ~~new~~ construction of any new apartment ~~complexes and condominiums unless the~~ complex, condominium, or multi-unit residential building~~(s) will be served by~~ unless:

1. a centralized heating, ventilation and/or air conditioning system ~~and~~ will serve all of the buildings within the apartment or condominium complex; and

2. the contractor can provide to the Cooperative an analysis demonstrating that the central unit will result in a favorable cost benefit relationship.

B. At a minimum, the cost/benefit analysis should consider the following elements for a central unit as compared to individual units:

1. Equipment and labor costs
2. Financing costs
3. Maintenance costs
4. Estimated kWh usage
5. Estimated kW demand on a coincident demand and non-coincident demand basis (for individual units)
6. Cost of meters and installation
7. Customer account cost (one account vs. several accounts)

~~151~~141. CUSTOMER PROVIDED FACILITIES

Each Customer obtaining service shall be responsible for all electric facilities on the Customer's side of the ~~point~~Point of ~~delivery,~~Delivery, including the service entrance~~,~~ and the meter socket. In addition, Customers obtaining 200 amp or larger service may be responsible for the service lines as determined by the Cooperative.

~~152~~142. METER LOCATION

Meters and service switches in conjunction with the meter shall be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection and where such activities will not cause intolerable interference and inconvenience to the Customer. The Customer shall provide and maintain, without cost to the Cooperative, at a suitable and easily accessible location, sufficient and proper space for installation of meters as set forth in the Codes and/or Trico's specifications.

~~153~~143. METER SERVICE LINE ALTERATION

Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer shall provide and have installed at his expense all wiring materials and equipment necessary for relocating the meter and service line connection and the Cooperative may make a charge not to exceed the actual cost for moving the meter and/or service line as set forth in Section 203.

~~154~~144. COOPERATIVE FACILITIES

A. The Cooperative shall provide facilities adequate to service the electric load agreed upon at the time of application for service or service upgrade in accordance with applicable ~~tariffs~~Tariffs and electric utility standards, but not electric load added after the last effective service agreement. If the Customer has any question as to the adequacy of the Cooperative's electric facilities then the Customer is responsible to obtain whatever assurance necessary to alleviate those concerns and the Cooperative is obligated to advise the Customer of the process and, if necessary, costs to ~~answer~~respond to the Customer's concerns.

B. The cost of any service line in excess of the size or length required to provide adequate service shall be paid as set forth in ~~Section~~Sections 104 and 105.

~~155~~145. RIGHTS-OF-WAY

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The Cooperative shall be granted rights-of-way and easement(s) over the property of the Customer, of sufficient width for the ~~erection~~construction, maintenance, operation, repair, replacement, relocation, removal or use of any and all wire, poles, machinery, supplies, equipment, metering and regulating and other apparatus and fixtures necessary or convenient for the supplying of electric service to the Customer. The Cooperative shall be given safe and unimpaired access at reasonable times to the premises of the Customer for the purpose of reading meters, testing, repairing, relocating, removing or exchanging any or all equipment or facilities necessary to provide or remove electric service to the Customer. Immediate and unannounced access may be necessary when the Cooperative is dealing with an outage or emergency. The required easement(s) and access shall be conveyed to the Cooperative prior to service being made available to the Customer without cost to the Cooperative. The Cooperative may discontinue service after proper notice is issued if there are violations of the required safe and unimpaired access.

~~156~~146. OBLIGATION FOR RIGHTS-OF-WAY

The Cooperative shall not be obligated to bear any part of the cost of obtaining rights-of-way, easements, licenses or permits. The Customer may be required to put up a non-interest bearing cost deposit(s) before work to obtain said rights-of-way can begin or continue. Any part of the deposit not used for obtaining rights-of-way may be applied toward and become part of the deposit required as set forth in Section ~~124~~119 or Part 2 of this policy.

It is the Customer or Applicant's responsibility to obtain the right-of-way from ~~the~~all third ~~party~~parties; however, the ~~cooperative~~Cooperative may assist when resources exist to do so~~.~~, at the expense of the Customer. It is the Customer or Applicant's responsibility to notify the third ~~party~~parties, neighbor(s) and/or adjacent landowners of the design, surveying and construction activities that could affect them or their surroundings.

~~157~~147. CUSTOMER FACILITIES IN ~~RIGHT~~RIGHTS-OF-WAY

When the Cooperative discovers that a Customer or his agent is performing work or has constructed facilities adjacent to or within an easement or rights-of-way and such work, construction or facility or establishes or owns any vegetation, ornamental or not, that obstructs or poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, rules, regulations, Codes or Trico's specifications or significantly interferes with the Cooperative's access to equipment, the Cooperative shall notify the Customer or his agent and shall take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

~~158~~148. RIGHTS-OF-WAY EASEMENTS FOR ELECTRIC DISTRIBUTION AND SERVICE LINES

The Cooperative shall construct or cause to be constructed and shall own, operate and maintain all electric distribution and service lines along public streets, roads and highways and on public lands and private property which the Cooperative has the legal right to occupy.

~~159~~149. RIGHTS-OF-WAY IN SUBDIVISIONS

Rights-of-way and easements suitable to the Cooperative must be furnished by the developer~~,~~ at no cost to the Cooperative and in reasonable time to meet service requirements. No electric facilities shall be installed by the Cooperative until the final grades have been established and furnished to the Cooperative. In addition, the easement strips, alleys, and streets must be graded by the developer to standards determined by the Cooperative, before the Cooperative will commence construction. Such clearance and grading must be maintained by the developer during construction by the Cooperative.

~~160~~150. RELOCATION OF FACILITIES

If, subsequent to construction, the clearance or grade is changed in such a way as to require relocation of facilities, or if deemed advisable by the Cooperative to require changing any underground to overhead or overhead to underground, the cost of any damage, relocation, replacement and/or resulting repairs shall be borne by the developer or the property owner of the real property which adversely affected the Cooperative facilities.

151. SERVICE UPGRADE POLICY

When the Cooperative receives written notification from the Customer of plans to upgrade an existing service panel or plans to increase the load demand or in any way alter the existing service configuration or source voltage, the Cooperative shall determine the ability and efficacy of its existing facilities to sustain safe, reliable, and adequate service to satisfy the Customer's service changes. The Cooperative will require load information and electrical data from the Customer and Cooperative will determine the alterations, upgrades, replacements, or additions of facilities, if any, required by the Cooperative to accommodate the Customer's changes. The Customer shall be charged the cost of construction and labor associated with retirement of any existing facilities for any service upgrade requiring material changes by the Cooperative. When in the Cooperative's opinion the existing facilities are eligible for replacement related to normal maintenance, a credit for the current value of the replacement materials may be given. The Cooperative shall apply a credit allowance exactly equal to the material and labor cost of any special equipment, such as transformers, required to serve the Customer. The cost of any line extension in excess of that allowed at no charge shall be paid for by the Applicant as a non-refundable Contribution in Aid of Construction. The conditions for supplying or refusing electric service in Sections 106 and 111, respectively, shall apply to service upgrades.

PART 2.
LINE EXTENSIONS

201. STATEMENT OF POLICY

The provisions of this policy shall define the conditions governing line extensions. Extensions of distribution or transmission facilities and lines of existing standard ~~existing~~ voltages necessary to furnish permanent electric service to Applicants and Customers of the Cooperative will be made by the Cooperative in accordance with the provision of this ~~part~~Part 2 and the Sections in Part 1 and 3 that are applicable, (~~i.~~e.g. 104 ~~and~~, 105 and 364). These provisions shall apply throughout the entire Service Area of the Cooperative unless modified by the provisions of an effective rate ~~tariff~~Tariff or specific order of the ~~Arizona Corporation Commission~~ACC, in which cases the provisions of the rate ~~tariff~~Tariff or order shall govern to the extent applicable.

The Cooperative will construct, own, operate and maintain lines along public streets, roads and highways, which the Cooperative has the legal right to occupy, and on public lands and private property across which rights-of-way and easements satisfactory to the Cooperative may be obtained without cost to or condemnation by the Cooperative.

A. Upon request by an Applicant for a line extension, the Cooperative shall prepare without charge, a preliminary sketch and rough estimate of the costs to be paid by the Applicant.

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B. Any Applicant for a line extension requesting the Cooperative to prepare detailed plans, specifications, or cost estimates, may be required to -deposit with the Cooperative an amount equal to the estimated cost of preparation. The Cooperative ~~shall~~, upon request, will make available within ~~ninety (90)~~ days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed line extension. Where the Applicant authorizes the Cooperative to proceed with the construction of the extension, the deposit shall be credited to the cost of -construction; otherwise, the deposit shall be non-refundable. If- the extension is to include oversizing of facilities to be done at the Cooperative's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdivisions providing the utility with approved plats shall be provided with plans, specifications, or cost estimates within 45 days after receipt of the deposit referred to ~~above.~~in Section 208B.

C. When the Cooperative requires an Applicant to contribute funds for a line extension, the Cooperative will furnish the Applicant with a line extension agreement.

D. All line extension agreements requiring payment by the Applicant shall be in writing and signed by both parties.

E. The provisions of this policy shall apply only to those Applicants who in the Cooperative's judgment will be a Permanent Service.

F. In all applications ~~for~~ of an equipment allowance of line extension costs, the ~~point of delivery~~equipment allowance shall follow the requirements of a Permanent Service Point of Delivery on the Customer's real property ~~shall be~~, at one location, unless ~~operation of~~ multiple ~~points of delivery is~~ Points of Delivery are deemed by the Cooperative reasonable and economical.

G. The Cooperative will charge a ~~new construction establishment fee~~New Service Establishment Fee per service to each Applicant requiring construction of a new service, ~~per~~in accordance with the applicable approved ~~tariffs~~Tariffs.

202. MINIMUM WRITTEN AGREEMENT REQUIREMENTS

Each line extension agreement or cost letter ~~shall~~, at a minimum, will include the following information:

A. Name and address of Applicant

B. Proposed service address and location

C. Description of requested service

D. Description and sketch of the requested service, line extension and if in a duly recorded real estate subdivision, of the subdivision with the lot numbers thereof

E. A cost estimate is to include materials, labor, reasonable overhead, and other costs as necessary

F. Payment terms

G. A concise explanation of any refunding provisions if applicable

H. Explanation of required easements, if any, or confirmation of existing easements adequate and legal for Trico's use prior to Trico's commitment to a line extension route and agreement

I. After the easements are obtained and the agreement is signed, the Cooperative will provide the estimated number of days to start construction and the number of days needed to complete construction of the line extension

J. Any service availability charge

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203. LINE EXTENSION COSTS

Line extension costs shall be established ~~by estimating each~~through use of ~~the following: computerized~~a power line design program, ~~including non-computerized items,~~and using Trico's historical costs, information, and data~~:~~, to calculate the following:

A. Material

B. Direct labor

C. Overhead: Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs such as:

1. Indirect labor
2. Engineering
3. Transportation
4. Taxes, e.g. (FICA, State & Federal Unemployment which are properly allocated to construction)
5. Insurance
6. Stores expense
7. General office expenses allocated to costs of construction
8. Power operated equipment
9. Employee Pension and Benefits

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10. Margins

11. Miscellaneous expenses ~~property~~properly chargeable to construction

D. All extension agreements shall be signed by the ~~Customers~~Customer, and all applicable deposits and/or contributions in aid of construction shall be paid to the Cooperative, prior to construction. ~~Trico shall specify that the Customer will pay only for those minimum size economic standard facilities needed to serve that particular Customer.~~

204. LINE EXTENSION MEASUREMENT

Line extension measurement for design and cost purposes shall be along the most direct and practical route of construction~~. This measurement shall include, but is not limited to primary, secondary and service lines.~~ required, and no equipment allowance shall be granted for any facility beyond the most direct and practical route to the nearest practical Point of Delivery as determined by the Cooperative.

205. EXTENSION TO RESIDENTIAL CUSTOMERS ~~OUTSIDE OF DULY RECORDED SUBDIVISIONS.~~

A Equipment Allowance: Upon satisfactory completion of the required site improvements to demonstrate the permanent nature of the Applicant's installation, the Cooperative shall grant an equipment allowance not to exceed $1,500 per Permanent Service, applied as a credit towards the Applicant's line extension fees. In addition, the Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformers and metering equipment, required to serve the customer. The Applicant shall pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension ~~as determined by the Cooperative~~, the Cooperative will make extensions to residential Applicants ~~of the Cooperative~~ from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

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~~B~~C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving ~~and~~, earthwork ~~for~~, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative. ~~When the Cooperative is prevented from installing its direct buried facility, by normal installation practices or due to terrain, the Applicant may be required to install a conduit system at no expense to the Cooperative, before the Cooperative commences construction.~~

~~C~~D. Cost of Extension Difference from Actual: Within ~~sixty (~~60~~)~~ days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the ~~estimated~~calculated costs, the Cooperative shall promptly ~~pay~~refund the Customer the difference within ~~thirty (~~30~~)~~

days. In such event if the actual costs are greater than the ~~estimated~~calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

206. ~~RESERVED FOR FUTURE ADDITIONS~~EXTENSION TO NON-PERMANENT RESIDENTIAL CUSTOMERS

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~~**207. RESERVED FOR FUTURE ADDITIONS**~~A. Equipment Allowance: Upon satisfactory completion of the required site improvements to demonstrate the permanent nature of the Applicant's installation, the Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformer and metering equipment required to serve the Customer. The Applicant shall pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to non-permanent residential Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

207. EXTENSION TO GENERAL SERVICE 3 AND 4 CUSTOMERS

A. Equipment Allowance: A Customer with an applicable rate Tariff of General Service 3 (GS3) or General Service 4 (GS4) is not eligible for an equipment allowance whatsoever, and is wholly responsible for the full-calculated cost of any line extension, which the Customer will pay as a non-refundable Contribution in Aid to Construction.

B. Line Extensions: Upon the payment of the required non-refundable Contribution in Aid to Construction for the construction of the line extension, the Cooperative will make extensions to GS3 and GS4 Applicants from its existing overhead or underground facilities of proper voltage and adequate capacity capable of serving the Customer.

C. Underground Extensions: The Applicant shall provide, at Applicant's expense, the trenching, backfilling (including any imported backfill required), compaction, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative.

D. Cost of Extension Difference from Actual: Within 60 days after the completion of construction, inspection and closeout of the line extension, the Cooperative may advise the Customer in writing of the actual costs of the line extension. In the event the actual costs are less than the calculated costs, the Cooperative shall promptly refund the Customer the difference within 30 days. In such event if the actual costs are greater than the calculated costs, the difference will be billed by the Cooperative in the next monthly statement of the Customer rendered by the Cooperative for electric service, or by an invoice if, for example, the line extension customer is a party not receiving electric service from the Cooperative.

208. OVERHEAD OR UNDERGROUND DISTRIBUTION FACILITIES WITHIN DULY-RECORDED REAL ESTATE SUBDIVISIONS OR COMPARABLE UNRECORDED DEVELOPMENT

A. General Statement: With respect to overhead or underground distribution facilities within a duly recorded subdivision~~ or a comparable unrecorded development (hereinafter referred to as "subdivision" or "development"),~~, the Cooperative will be responsible for the construction of the electric facilities for Residential Customers. All Commercial Customers within subdivision will be covered by ~~Section 209.~~Sections 201 through 204, and either Section 207 or 209 (whichever is applicable). In the event the extension is underground the Developer of the recorded subdivision shall provide and install at Developer's expense the trenching, ~~conduit system, pull boxes,~~ backfilling (including any imported backfill required), compaction, repaving~~ and~~, earthwork~~ for~~, conduit systems, pull boxes~~ or~~, and other preparation for electrical apparatus necessary for the installation of underground facilities, all in accordance with the specifications and schedules of the Cooperative. At its option, the Cooperative may elect at the Developer's expense to perform the necessary activities to fulfill the Developer's responsibility hereunder; provided, the expense to the Developer is equal to or less than the expense in the event the Developer performed such activities.

B. Application Fee: ~~Developers of recorded subdivisions requiring underground distribution facilities shall be required to furnish and install a conduit system according to the Cooperative's specifications, and shall do so at no expense to the Cooperative. The Developer shall pay a seventy-five dollar ($75) per lot nonrefundable~~The Developer shall pay a $75 per lot non-refundable application fee before the Cooperative shall be obligated to commence the electric design for the subdivision, including planning or design of off-site facilities. For extensions in subdivisions ~~which do~~ not directly ~~connect~~connected to facilities ~~that serve electricity~~ providing service to subdivision lots, but ~~are intended to~~that will be connected to the Cooperative's facilities ~~that do provide~~providing service~~ of electricity~~ to subdivision lots ("Spine Facilities" or "Backbone Facilities"), the Cooperative shall collect a nonrefundable application fee equal to the design, inspection, and rights-of-way costs ~~estimated~~. In that case, the fee will be calculated to serve such Spine Facilities, or

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~~5%~~five percent of the total ~~estimated~~calculated cost to construct, design, inspect, and obtain right-of-way, of such Spine Facilities, whichever is greater.

C. Agreement: Distribution facilities will be constructed by the Cooperative within a subdivision or development in advance of application for Permanent Service, after the Cooperative and the Developer of the subdivision or development have entered into a written contract which provides, among other things, for:

1. Equipment Allowance for Developers: The Cooperative shall apply an allowance exactly equal to the material and labor cost of any transformers required to serve the future Customers. The Applicant will pay for the cost of any line extension, in excess of that allowed at no charge, as a non-refundable Contribution in Aid of Construction. If the calculated cost of the line extension does not exceed the maximum amount of the equipment allowance, the equipment allowance shall be exactly equal to the calculated cost of the line extension and is exclusive and non-transferable.

~~1.~~2. Contribution in Aid of Construction: The total ~~estimated~~calculated installed cost of such distribution facilities and Spine Facilities, exclusive of ~~meters~~transformers, shall be paid to the Cooperative as a non-refundable Contribution in Aid of Construction. The total ~~estimated~~calculated installed cost shall include all electric facilities that include~~-~~ Spine Facilities or Backbone Facilities required and sized to serve the total construction of the subdivision or development, and may include all or a portion of off-site facility extensions or off-site facility improvements which the Cooperative has deemed necessary to serve the subdivision or development. The Developer shall be required to install all ~~required~~ conduit~~, special~~ systems, equipment ~~basements~~ and transformer basements, and furnish and install all concrete equipment pads per the Cooperative's requirements, including all such conduit and associated facility to the service side of any customer applying for service before the Cooperative is obligated to serve said Customer. The ~~nonrefundable~~non-refundable lot application fee required per ~~Rule~~Section 208.B shall be deducted from the total ~~estimated~~calculated installed cost. A written agreement with a term of five ~~(5)~~ years commencing from the date of completion of construction of these electric facilities, shall be executed by the Developer and the Developer shall pay Trico all deposits in the amounts stated in the agreement prior to the installation of the electric facilities. If after five years, from the completion of the construction of the distribution facilities the development is not complete, the Cooperative shall have the right to execute and record a lien on the unsold portion of the property to secure: (1) the payment by the Developer to the Cooperative of any existing and new service availability charges, which is the fixed fee set forth in the applicable Tariff for idle services; or (2) the cost to the Cooperative to retire or abandon the unused facilities, whichever in the Cooperative's opinion is in the best interest of the Cooperative; or (3) the Cooperative shall have the right to retire any or all of the idle facilities it deems necessary, with proper notice, in accordance with Section 364.

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~~2.~~3. Actual Cost of Construction. Within ~~sixty (60)~~ days after the completion of construction, inspection and closeout by the Cooperative of the facilities to serve the subdivision or development, the Cooperative may advise the Developer in writing of the actual costs of such construction. In the event the actual costs are given to the Customer and such actual costs are less than the ~~estimated~~calculated cost for which payment has been made by the Developer to the Cooperative, the Cooperative shall promptly refund to the Developer the difference. In such event if such actual costs are greater than such ~~estimated~~calculated cost, the Cooperative shall invoice to Customer and the Customer shall promptly pay such invoiced amount.

D. Service to Residential Customer~~.~~: Each residential customer or ~~their~~his or her agent (Applicant) within duly recorded real estate subdivisions will be required to make application for service~~. Trico will design and estimate the total cost of servicing said application and a cost letter will be provided to the Applicant for the Applicant to pay the amount as Contribution in Aid of Construction. When a development is such that all electric facilities are not installed by the Developer, the Applicant will be required to furnish and install any conduit system, install any transformer basements and furnish and install all equipment pads per the Cooperatives requirements, at no expense to the Cooperative, prior to the Cooperative's construction of said secondary service and any primary when deemed necessary~~ in accordance with Sections 201-205.

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209. ALL OTHER EXTENSIONS.

~~A~~A non-refundable Contribution in Aid of Construction for line extensions is required for all other line extensions of any class or type not otherwise provided in these ~~Rules.~~RRLEP, but which are covered by the standard offer provisions of Section 104. The following formula will determine the amount of the ~~Customer's~~Applicant's non-refundable Contribution in Aid of Construction for such extensions~~ shall be the total of the applicable items set forth~~. If the amount calculated below is zero or negative, no Contribution in ~~Section 203.~~Aid of Construction is required for provision of electric service.

~~**210. RESERVED FOR FUTURE ADDITIONS**~~

~~**211. RESERVED FOR FUTURE ADDITIONS**~~

~~**212. RESERVED FOR FUTURE ADDITIONS**~~

~~**213. RESERVED FOR FUTURE ADDITIONS**~~

~~**214**~~Cooperative's Allowable Investment = Annual Revenue / Return Factor

Total Project Cost = Direct Cost + System Cost

Applicant's Contribution = Total Project Cost – Cooperative's Allowable Investment

Where:

Direct Cost = The cost of distribution or transmission facilities necessary to provide electric service to Customer, determined by estimating all necessary expenditures, including, but not limited to, metering, services, transformers, and rearrangement of existing electrical facilities. This cost includes only the cost of the above-mentioned facilities that are necessary to provide service to the particular customer requesting service and does not include the costs of facilities necessary to meet future anticipated load growth, or to improve the service reliability in the general area for the benefit of existing and future customers.

System cost = Cooperative's average allocated investment costs associated with Customer's on-peak and off-peak demands as approved in Cooperative's most recent rate case for the appropriate class of Customer. Investment cost accounts considered in determining the allocated investment costs are those applicable 300 series FERC accounts and other rate base items, including plant held for future use, cash working capital, materials and supplies, prepayments, customer deposits, reserve for insurance and other cost-fee capital.

Annual Revenue = Estimated annual revenue from Customer computed from estimated demand and kWh, excluding fuel cost and sales tax.

Return Factor = Fixed charge rate, including O&M, taxes, insurance, necessary to convert an annual revenue stream to the total revenue associated with estimated life of project.

The Cooperative's Allowable Investment will be determined based on Annual Revenue for the current 12-month period.

210. CONVERSION OF EXISTING LINE

A. To the extent the provisions of Arizona Revised Statutes, Title 40, Chapter 2, Article 6.1 ("Article 6.1") are applicable, a conversion of ~~single phase~~ overhead to underground lines shall be made pursuant to Article 6.1.

B. In the event that Article 6.1 is not applicable, when requested by Customer or Customers to convert all or a portion of distribution lines from single-phase to three-phase overhead, or single phase to three-phase underground or from overhead to underground, the following shall be applicable to such conversion:

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1. The Customer(s) shall provide all utility easements and access as required by ~~Rule 155~~Section 145 at no cost to the Cooperative.

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2. The Customer(s~~)~~), at the Customer's (Customers') expense, shall provide ~~all~~the trenching, ~~all conduit when required, select backfill where required,~~ backfilling~~,~~ (including any imported backfill required), compaction ~~and all concrete work and concrete equipment pads and equipment basements,~~

~~according to~~, repaving, earthwork, conduit systems, pull boxes or other preparation for all electrical apparatus necessary for the installation of underground facilities, in accordance with the specifications and schedules of the Cooperative and local codes and shall perform all street, curb and sidewalk repairs at the Customer's expense in accordance with local jurisdiction prior to the Cooperative's commencement of the conversion.

3. The Customer(s) shall pay to the Cooperative a Contribution in Aid of Construction the cost of the existing line at present value, less credit for salvage, if any, plus retirement cost, plus ~~the~~any applicable line extension ~~cost~~costs, less any applicable equipment allowances, prior to the start of construction.

4. The Customer(s) shall sign any additional agreements, which may include a consensual lien to secure payment of all unpaid obligations of the Customer(s) pursuant to this Section ~~214~~210, which shall be recorded in the office of the county recorder.

~~215. RESERVED FOR FUTURE ADDITIONS~~

~~216~~211. ADVANCES UNDER PREVIOUS ~~RULES~~RRLEP AND CONTRACTS

At the time these new ~~Line Extension Policies~~RRLEP are approved by the ~~Arizona Corporation Commission~~ACC all existing agreements, contracts, or cost letters with or to customers shall remain in effect in accordance with the term or time period stated in those agreements, contracts, or cost letters; and amounts advanced under the conditions established by a ~~Rule~~Section previously in effect shall remain nonrefundable or will be refunded in accordance with the requirements of such effective contract under which the advance was made.

~~217~~212. EXTENSIONS FOR TEMPORARY SERVICE

Extensions for ~~temporary service or~~Temporary Service (including for operations of a speculative character or questionable permanency) will be made in accordance with the provisions pertaining to ~~temporary service~~Temporary Service set forth in Section ~~119~~115 through ~~122~~118.

~~218~~213. SPECIAL OR EXCESS FACILITIES

Under these ~~Rules~~RRLEP, the Cooperative shall install only those facilities which it deems are necessary to render service in accordance with the rate ~~tariffs~~Tariffs. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Cooperative normally would install, the extra cost thereof shall be paid by the Customer.

~~219~~214. PRIMARY VOLTAGE SERVICE

When the Cooperative ~~provides~~agrees to provide primary service to a ~~point~~new or existing Customer, the Point of ~~delivery, such point of delivery~~Delivery shall be determined solely by the Cooperative. The Customer shall provide the entire distribution system between the ~~point~~Point of ~~delivery to~~Delivery and the Customer's load, unless otherwise specified in the written agreement between the Customer and the Cooperative~~, which~~ (where the agreement shall provide for ~~Facilities Charge~~facilities charge(s)), for the Cooperative's distribution on the Customer's side, from the ~~point~~Point of ~~delivery.~~ Delivery). The system will be treated as primary service for the purposes of billing. The Cooperative reserves the right to approve of or require modification of the Customer's distribution plan or system prior to installation and connection with Trico's system. Instrument transformers, meters, poles and all other equipment associated with the primary service metering will be installed by the Cooperative at the Customer's expense. The Customer and the Cooperative will agree on who will pay for the facilities on the Customer's side (load side) of the ~~point~~Point of ~~delivery~~Delivery. Facilities ~~Charge~~charge(s) as part of the monthly power bill will include applicable charges for operations, maintenance, depreciation, customer expense, administration expense, and rate of return. ~~The~~Unless otherwise set forth in the written agreement between the Customer and the Cooperative, the Customer will pay, as a Contribution in Aid of Construction, 100 percent -of the cost of ~~the~~any line extension – as well as any and ~~the~~all upgrades ~~of~~to the distribution and transmission facilities between the nearest existing Trico power facility capable of providing ~~the requested load to~~for the Customer's ~~requested~~load and the point of delivery, ~~constructed~~ of such size and capacity required to serve ~~that specific individual~~ the Customer, less any ~~oversized~~oversize or ~~rerouted~~excess facilities constructed for the Cooperative's system needs. The Customer will have the option to pay for the cost of ~~the~~all upgrades to the nearest existing facilities that may not otherwise be capable of providing the requested load to the Customer's requested ~~point~~Point of ~~delivery~~Delivery if it would be the least cost to the Customer~~.~~.

~~220. RESERVED FOR FUTURE ADDITIONS~~

~~221. RESERVED FOR FUTURE ADDITIONS~~

~~222. RESERVED FOR FUTURE ADDITIONS~~

~~223~~215. PROTECTIVE EQUIPMENT

The Customer shall provide, own, and maintain such protective equipment necessary to ensure isolation of the Customer's service from the Cooperative's system due to abnormal conditions. It is the responsibility of the Customer to provide protection and/or power-conditioning devices required to provide the quality of power necessary for optimum performance of ~~his~~ voltage-sensitive equipment. Voltage sensitive equipment is defined as equipment that does not function with utility grade power, e.g. computers. Some motors may be sensitive to the loss of a phase. It is the Customer's responsibility to protect their equipment from loss of voltage, phase ~~condition~~, frequency, or deviation in standard voltage.

~~224~~216. CUSTOMER GENERATION EQUIPMENT

A. A Customer installing any means of stand-by~~,~~ generation, which is not intended to become interconnected with the Cooperative's service, shall install a double-throw transfer switch that will prevent connection of the Customer's equipment to the Cooperative's power system.

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B. A Customer installing any generation equipment intended to operate in parallel with the Cooperative's electric system, must meet all the provisions of the Cooperative's policies and guidelines. The Customer shall make no connections to the electric system without specific inspection and approval by the Cooperative and shall enter into a parallel operation, power sale and interconnection agreement with the Cooperative.

C. The Cooperative shall be notified to inspect, and if satisfactory, approve said connection. Any unapproved installations shall be grounds for immediate disconnection of the Customer's service.

~~225~~217. RELOCATION OF COOPERATIVE FACILITIES

When the Cooperative is requested to relocate its facilities for the benefit and/or convenience of a Customer, the Customer shall reimburse the Cooperative for the total cost of the work to be performed prior to the start of construction. When the relocation involves underground facilities, the Customer's responsibilities in Section 210 shall apply.

~~226. GENERAL REQUIREMENTS AND PROVISIONS~~

~~A. During a shortage of electric power and/or energy as determined by the Cooperative or any public agency, the Cooperative shall have the right to curtail the supply of electric power and/or energy.~~

~~B. Electricity furnished by the Cooperative shall not be resold by the Customer except as a service made under a special written contract acceptable to the Cooperative.~~

~~C. A copy of these Rules shall be posted on the Cooperatives internet site and upon written request by Applicant or Customer, the Cooperative will furnish a copy to the Customer.~~

~~D. Agreements for service shall not be assignable without the Cooperative's prior written consent. Assignments of refunds pursuant to a line extension agreement shall be effective only after a proper written assignment is delivered to the Cooperative.~~

~~E. Notification to the Customer shall be deemed to have been given when mailed to the Customer by first class mail at the Customer's last address of record, faxed to the Customer at a fax number furnished or published by the Customer, or E-mailed to the Customer at an E-mail address furnished or published by the Customer as shown on the records of the Cooperative.~~

~~F. All advances made by Customers that are refundable, shall be non-interest bearing.~~

~~G. The Cooperative shall not be required to extend its lines to any Customer or enter into any written agreement with any Customer for a line extension in the event the Cooperative is entitled to refuse service to the Customer pursuant to Section 111 or other sections of these Rules, Regulations and Policies.~~

~~227. RETIREMENT OF FACILITIES~~

~~See Section 372.~~

PART 3.
METER READING, BILLING, COLLECTION AND TERMINATION OF SERVICE PROCEDURES

301. FREQUENCY OF METER READING

The Cooperative reserves the right to read meters on a schedule less frequent than monthly where the location is so remote or inaccessible that fewer actual readings are in the best interest of operating economy. However, in no event will meters be read less frequently than every three ~~(3)~~ months. Every attempt shall be made to read meters monthly on as close to the same day as practical. However, meter readings may be scheduled for periods of not less than 25 days or more than 35 days.

302. ESTIMATION OF BILL, FIRST AND SECOND MONTH

If the Cooperative is unable to read the meter on the scheduled meter read date, the Cooperative will estimate the consumption for the first and, if applicable, the second billing period thereafter in accordance with the Estimation Methodology Tariff, Schedule EM as approved by the ~~Arizona Corporation Commission, Decision 69735~~ACC.

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303. ESTIMATION OF BILL AFTER SECOND MONTH

After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Cooperative will make every attempt to secure an accurate reading of the meter.

304. ~~RESERVED FOR FUTURE ADDITIONS~~

~~305.~~ ESTIMATED BILLS

Subject to the provisions of Section ~~307~~306, estimated bills will be issued according to Trico's ~~Bill~~ Estimation Methodology Tariff ~~(Decision No. 69735)~~, Schedule EM and under the following conditions:

A. Labor shortages or work stoppages beyond the control of the Cooperative.

B. Severe weather conditions or emergencies or which prevent the Cooperative from reading the meter.

C. Circumstances that make it dangerous or impossible to read the meter, including but not limited to: locked gates, blocked access to meters, threatening or abusive customers, vicious or dangerous animals or missing meters.

D. Failure of customer who reads his own meter to deliver his meter reading to the Cooperative in accordance with the requirements of the Cooperative billing cycle.

E. To facilitate timely billing for customers using load profiles.

305. ~~306.~~ NOTICE OF ESTIMATION

Each bill based on estimated usage will indicate that it is an estimated bill ~~and note the reason for estimation~~.

~~307.~~ 306. RECORD OF CONSUMPTION

The registration of the Cooperative's meter at the Customer's ~~point~~Point of ~~delivery~~Delivery shall constitute evidence of the amount of energy and/or billing demand used by the Customer, except where unmetered service is supplied. However, in the event of failure of the Cooperative's meter or inability of an authorized representative of the Cooperative to obtain an actual reading, a reasonable estimate shall be made per Section 302.

~~308~~307. RATE TARIFFS BASED ON SINGLE POINT OF DELIVERY

Unless otherwise specifically provided in the rate ~~tariff~~Tariff or by contract, each of the Cooperative's rate ~~tariffs~~Tariffs are based upon the supplying of electric service to one Customer at a single ~~point~~Point of ~~delivery~~Delivery and at a single voltage and phase classification, and any additional service supplied to the same Customer at other ~~points~~Points of ~~delivery~~Delivery or at a different voltage of phase classification shall be separately metered and billed, except as provided in Section ~~319~~317.

~~309~~308. MEASURING OF ELECTRIC SERVICE

All energy sold to Customers, and except that sold according to fixed charge ~~tariffs~~Tariffs, shall be measured by commercially acceptable measuring devices owned and maintained by the Cooperative, except where it is impractical to install meters, such as street lighting or security lighting, or where otherwise authorized by the ~~Commission~~ACC.

~~310~~309. MORE THAN ONE METER

When there is more than one ~~(1)~~ meter at a location, the service and metering equipment shall be so tagged or plainly marked as to indicate the location metered.

~~311~~310. METER MULTIPLIERS

Meters which are not direct reading shall have the multiplier plainly marked on the meter, meter panel or meter base.

~~312~~311. RECORDING METER DATA

All data taken from recording meters shall be marked with the date of the record, meter number, Customer information, data multiplier, transformer multiplier(s), date removed and items measured.

~~313~~312. METER SETTINGS

Metering equipment shall not be set "fast" or "slow" to compensate for supply transformer or line losses.

313. ~~314.~~ CUSTOMER REQUESTED REREADS

The Cooperative ~~shall~~, at the Customer's request ~~of a Customer~~, will reread that Customer's meter once within ten ~~(10)~~ working days after such request by the Customer.

~~315.~~ 314. REREAD CHARGE

~~Any reread~~ The Cooperative may ~~be charged to~~charge the Customer for any reread at a rate on file and approved by the ~~Commission~~ACC in Trico's Schedule of Special Charges, ~~provided that~~if the original reading was not in error. When a reading is found to be in error, the reread shall be at no charge to the Customer.

~~316. RESERVED FOR FUTURE ADDITIONS~~

~~317~~315. ACCESS TO CUSTOMER PREMISES

The Cooperative shall at all times have the right of safe ingress to and egress from the premises at all reasonable hours for any purpose reasonably connected with the Cooperative's property used in furnishing service, reading meters, and the exercise of any and all rights secured to it by law or these ~~Rules~~RRLEP. The Cooperative will continue to ~~physically~~ check the meter, including Automated Meters, periodically or for cause. Failure on the part of the Customer to comply with these ~~Rules~~RRLEP for access to its meter may lead to the discontinuance of service. An authorized agent/representative of the Cooperative, is authorized to enter any premises using Trico's electricity to inspect the use and quality of the electricity (A.R.S. § 40-431), to read meters, and to connect or disconnect services (A.A.C. R14-2-211).

~~318~~316. FREQUENCY AND METHODS OF BILLING.

The Cooperative shall bill monthly for services rendered by sending the bill ~~and notices~~ via the United States Mail, e-mail, posting to a secure website or other acceptable means of delivery.

~~319~~317. COMBINING OF METER READINGS

Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two or more meters will not be combined unless otherwise provided for in the Cooperative's ~~tariffs~~Tariffs.

~~320~~318. MINIMUM BILLING INFORMATION

Each bill for residential service will contain the following minimum information:

A. Date and meter reading at the start of the billing period or number of days in the billing period

B. Date and meter reading at the end of the billing period

C. Billed usage and demand

D. Rate ~~tariff~~Tariff number/designation

E. Cooperative's telephone number

F. Customer's name

G. Service account number

H. Amount due and due date

I. Past due amount and subject to termination date

J. Adjustment factor, where applicable

K. Taxes

L. The ~~Arizona Corporation Commission and~~ACC's address~~, thereof~~.

~~321~~319. BILLING TERMS

All bills for electric service are due and payable no later than ~~fifteen (~~15~~)~~ days from the date the bill is rendered as evidenced in Section ~~322. Any~~320. The Cooperative shall consider any bill delinquent when payment is not received within this time-frame ~~shall be considered delinquent and could~~and the Customer may incur a late payment charge.

~~322~~320. EVIDENCE OF RENDERING DATE

For purposes of this ~~rule~~Section, the date a bill is rendered may be evidenced by:

A. The postmark date

B. The mailing date

C. The billing date shown on the bill (however, the billing date shall not differ from the postmark or mailing date by more than two ~~(2)~~ days)

D. The transmission date of electronic bills

~~323. RESERVED FOR FUTURE ADDITIONS~~

~~324~~321. DELINQUENT BILLS

All delinquent bills for which payment has not been received within five ~~(5)~~ days shall be subject to the provisions of the Cooperative's termination procedures.

~~325~~322. PLACE OF PAYMENT

All payments shall be made at or mailed to the office of the Cooperative or to the Cooperatives authorized payment agency. Payments can also be made by credit card, e-check, bank draft or recurring credit card payments. No payment shall be deemed made until received by the Cooperative. A service fee may be required on credit card and e-check transactions.

~~326~~323. APPLICABLE RATE TARIFF

Each Customer shall be billed under the applicable ~~tariff~~Tariff indicated in the Customer's application for service.

~~327~~324. FAILURE TO RECEIVE BILLS/NOTICES

Failure by the Customer to receive bills or notices, which ~~have been~~were properly placed in the United States mail, by secure website, by e-mail or other acceptable means of delivery, shall not prevent such bills from becoming delinquent nor relieve the Customer of his obligations therein.

~~328~~325. COMMENCEMENT DATE

Charges for service commence when the service is installed and connection made, whether used or not.

~~329~~326. METER ERROR CORRECTIONS

If any meter, after testing, is found to be more than three percent ~~(3%)~~ three percent in error, either fast or slow, proper correction between three percent ~~(3%)~~three percent and the amount of the error shall be made of previous readings and adjusted bills shall be rendered according to the following terms:

A. For the period of three ~~(3)~~ months immediately preceding the removal of such meter from service for ~~test~~testing, or from the time the meter was in service since last tested, but not exceeding three ~~(3)~~ months since the meter shall have been shown to be in error by the test.

B. From the date the error occurred, if the date of the cause can be definitely fixed.

~~330~~327. METER TEST / BILLING ADJUSTMENT

No adjustment shall be made by the Cooperative except to the Customer last served by the meter tested.

~~331~~328. CUSTOMER REQUESTED METER TESTS

The Cooperative shall test a meter upon Customer request, and the Cooperative shall be authorized to charge the Customer for such meter test according to the ~~tariff~~Tariff on file and approved by the ~~Commission~~ACC. However, if the meter is found to be in error by more than three percent ~~(3%)~~,, no meter--testing fee will be charged to the Customer.

~~332~~329. UNAUTHORIZED CONNECTIONS/ALTERATIONS

No person, except a representative acting on behalf of the Cooperative shall alter, remove or make any connections to the Cooperative's meter or service equipment.

~~333~~330. METER SEALS

No meter seal may be broken or removed by anyone other than an authorized representative of Trico acting on behalf of the Cooperative. However, the Cooperative may give its consent to break or remove the seal by an approved electrician, employed by a Customer, when deemed necessary to the Cooperative.

~~334~~331. METER TAMPERING AND THEFT OF POWER

In cases of tampering with meter installations, interfering with the proper working thereof; or any other theft of service by any person, or evidence of any such tampering, interfering, theft, or service diversion, including the falsification of Customer read meter readings; that service shall be liable to immediate discontinuance of service.

~~335~~332. TAMPERING AND THEFT CHARGES

Pursuant to Arizona Revised Statutes, Sections 40-491 through 40-~~494~~495, the Cooperative shall be entitled to collect from the Member/Customer whose name the service is in, the appropriate rate for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also any additional security deposits as well as all expenses incurred by the Cooperative for property damages, investigation of the illegal act, and all legal expenses and court costs if necessary. Arizona law allows Trico to collect triple damages from power thieves.

~~336~~333. ALTERNATIVE METHODS OF PAYMENT

Customers may pay their bills for electric service furnished them by the Cooperative in the following alternative methods:

A. Payment by cash, bank cashier's check, bank certified check, valid personal check or electronic check drawn on a commercial bank insured by the Federal Deposit Insurance Corporation or a savings and loan association insured by the Federal Savings and Loan Insurance Corporation.

B. Payment by a valid credit card accepted by the Cooperative. Payment by credit card shall not be deemed accepted by the Cooperative unless and until authorized by the bank administering the use of the credit card for the Customers.

C. A service fee may be required on electronic transactions.

~~337~~334. PAYMENT TRANSACTION RETURN OR CHARGE BACK

The Cooperative shall be allowed to recover a fee, as approved by the Commission, for each instance where Customer tenders payment for electric service with an insufficient funds check, payment transaction return or charge back.

~~338~~335. METHODS OF PAYMENT AFTER RECEIPT OF TRANSACTION RETURN OR CHARGE BACK

When the Cooperative is notified by the Customer's bank that there is a payment transaction return tendered for electric service, the Cooperative may require the Customer to make payment in cash, by money order, ~~cashiers~~cashier's check, or other means which guarantee the Customer's payment to the Cooperative.

~~339~~336. CUSTOMER'S OBLIGATION TO RENDER PAYMENT

A Customer who tenders payment transaction return shall in no way be relieved of the obligation to render payment to the Cooperative under the original terms of the bill nor defer the Cooperative's provision for termination of service for nonpayment of bills. In the event a Customer makes a partial payment, the Cooperative may accept the partial payment and apply it on the Customer's account. However, the Customer shall remain liable to the Cooperative for the unpaid portion of the account and for the purpose of these ~~Rules~~RRLEP; only full payment shall be deemed to constitute payment.

~~340~~337. PAYMENT TRANSACTION RETURN OR CHARGE BACK LIMITATION

Only cash, money order or ~~cashiers~~cashier's checks will be accepted if two ~~(2) NSF~~insufficient funds checks, transaction returns or charge backs have been received by the Cooperative within a twelve-~~-~~month period in payment of any billing. A returned check cannot be paid with another check.

~~341~~338. PAYMENT TRANSACTION RETURN OR CHARGE BACK LIMITATION AND TERMINATION OF SERVICE

Electric service will be subject to disconnect following the procedure as set forth in Section ~~362~~355 for payment transaction return or charge backs that have not been made good.

~~342~~339. LEVELIZED BILLING PLAN

The Cooperative ~~may~~, at its option, may offer its Customers a levelized billing plan.

~~343~~340. LEVELIZED BILLING PLAN REQUIREMENTS

If the Cooperative offers a levelized billing plan, the Cooperative shall develop, upon the ~~Customer~~Customer's request, an estimate of the Customer's levelized billing for a ~~twelve~~12-month period based upon:

A. Customer's actual consumption history, which may be adjusted for increased past usage and abnormal conditions such as weather variation.

B. For new Customers, the Cooperative will estimate consumption based on the Customer's anticipated load requirements.

C. The Cooperative's ~~tariffs~~Tariffs approved by the ~~Commission~~ACC applicable to that Customer's class of service.

~~344~~341. LEVELIZED BILLING PLAN INFORMATION TO CUSTOMER

The Cooperative shall provide the Customer a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly electric bill, and the Cooperative's right to adjust the Customer's billing for any variation between the Cooperative's estimated billing and actual billing.

~~345~~342. MINIMUM INFORMATION ON MONTHLY LEVELIZED BILL

For those Customers being billed under a levelized billing plan, the Cooperative shall show at a minimum, the following information on the Customer's monthly bill:

A. Actual consumption

B. Amount due for actual consumption

C. Levelized billing amount due

D. Accumulated variation in actual versus levelized billing amount

~~346~~343. ADJUSTMENTS TO LEVELIZED BILLS

The Cooperative may adjust the Customer's levelized billing in the event the Cooperative's estimate of the Customer's usage and/or cost should vary significantly from the Customer's actual usage and/or cost; such review to adjust the amount of the levelized billing may be initiated by the Cooperative or upon Customer request.

~~347~~344. DEFERRED PAYMENT PLAN

The Cooperative ~~may~~, prior to termination, may offer to qualifying residential Customers a deferred payment plan for unpaid bills.

~~348~~345. DEFERRED PAYMENT PLAN AGREEMENT TERMS

Each deferred payment agreement entered into by the Cooperative and the Customer due to the Customer's ~~inability~~Inability to ~~pay~~Pay an outstanding bill in full shall provide that service will not be discontinued if:

A. Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement.

B. Customer agrees to pay all future bills for utility service in accordance with the billing and collection ~~tariffs of the Cooperative~~Tariffs of the Cooperative, unless otherwise noted the deferred portion of the unpaid balance will be due at the same time as normal monthly bills; the deferred balance will be included as a line item on the bill.

C. Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments over a period not to exceed six ~~(6)~~ months.

~~349~~D. Any Customer utilizing a deferred payment agreement will be required to sign a mutually agreed upon payment schedule. Any Customer failing to meet the terms of the deferred payment plan agreement will be eligible for termination of service without notice.

346. DETERMINING INSTALLMENT PAYMENT SCHEDULE

For the purposes of determining a reasonable installment payment schedule under these ~~Rules~~RRLEP, the Cooperative and the Customer shall ~~give consideration to~~consider the following conditions:

A. Size of the account

B. Customer's ability to pay

C. Customer's payment history

D. Length of time that the debt has been outstanding

E. Circumstances which resulted in the debt being outstanding

F. Any other relevant factors related to the circumstances of the Customer

~~350~~347. ESTABLISHMENT OF AGREEMENT/TERMINATION DATES

Any Customer who desires to enter into a deferred payment agreement shall execute such agreement prior to the Cooperative's scheduled termination date for nonpayment of bills; Customer failure to execute a deferred payment agreement prior to the scheduled termination date shall not prevent the utility from discontinuing service for nonpayment. A deferred payment agreement may include a late payment charge as approved by the ~~Commission~~ACC in a ~~tariff~~Tariff proceeding.

~~351~~348. REQUIREMENTS OF DEFERRED PAYMENT AGREEMENT

If a Customer has not fulfilled the terms of a deferred payment agreement, the Cooperative shall have the right to disconnect service pursuant to the Cooperative's termination of ~~service rules~~procedures and, under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

~~352. RESERVED FOR FUTURE ADDITIONS~~

~~353. RESERVED FOR FUTURE ADDITIONS~~

~~354. RESERVED FOR FUTURE ADDITIONS~~

~~355~~349. CHANGE OF OCCUPANCY

Not less than three ~~(3)~~ working days advance notice must be given to the Cooperative to discontinue service or to change occupancy.

~~356~~350. OUTGOING PARTY RESPONSIBILITY

The outgoing party shall be responsible for all electric service provided and/or consumed up to the scheduled turn-off date. The outgoing party is also responsible for providing access to the meter so that Trico may obtain a final meter reading.

~~357. RESERVED FOR FUTURE ADDITIONS~~

~~358~~351. NON-PERMISSIBLE REASONS TO TERMINATE ELECTRIC SERVICE

The Cooperative will not disconnect service for any of the reasons stated below:

A. Delinquency in payment for services rendered to prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises.

B. Failure of the Customer to pay for services or equipment, which are not regulated by the ~~Commission~~ACC.

C. Failure to pay for a bill to correct a previous under billing due to an inaccurate meter or meter failure if the Customer agrees to pay over a reasonable period of time.

D. The Cooperative will not terminate residential service where the Customer has an inability to pay and is making arrangements for payment, alternative power supply, or to relocate the resident, in the event that:

   1. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous or life threatening to the Customer or a permanent resident residing on the Customer's premises, health, or

   2. Life supporting equipment used in the home that is dependent on electric service for operation of such apparatus, or

   3. Where ~~weather will be especially dangerous to health~~Weather Especially Dangerous To Health as defined herein or as determined by the ~~Commission~~ACC occurs.

E. Residential service to ill, elderly, or handicapped persons who have an ~~inability~~Inability to ~~pay~~Pay will not be terminated until all of the following have been attempted:

   1. The Customer has been informed of the availability of funds from various government and social assistance agencies of which the Cooperative is aware.

   2. A third party previously designated by the Customer has been notified and has not made arrangements to pay the outstanding electric bill, provided that the Customer, or a third person designated by the Customer, uses his or her best efforts to obtain funds to pay the Cooperative's bills from various governmental or social assistance agencies which are known to them.

   3. Arrangements or attempts to receive utility assistance must be made prior to the termination date on the bill. Payment guarantees from government or social assistance agencies must be received by the Cooperative via fax or e-mail prior to termination. Any balance not paid by the assistance or guaranteed payment, is the responsibility of the Customer and subject to termination in accordance with Section 355.

F. A Customer utilizing the provisions of D. or E. above may be required to enter into a deferred payment agreement with the Cooperative within ~~ten (~~10~~)~~ days after the scheduled termination date.

G. Disputed bills where the Customer has complied with the ~~Commission's~~ACC's Rules on Customer bill disputes.

~~359~~352. TERMINATION OF SERVICE WITHOUT NOTICE

Electrical service may be disconnected without advance written notice under the following conditions:

A. The existence of an obvious and imminent hazard to the safety or health of the Customer or the general population or the Cooperative's personnel or facilities.

B. The Cooperative has evidence of meter tampering, theft of service, or damage or loss to the Cooperative's property pertaining to the service to the Customer.

C. Failure of a Customer to comply with the curtailment procedures.

D. An emergency requiring immediate discontinuance of service.

E. Generator installations not approved by the Cooperative.

~~360~~F. Customer failing to meet the terms of the deferred payment plan agreement.

353. RESTORATION OF SERVICE

The Cooperative shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Cooperative.

~~361~~354. SERVICE TERMINATION WITHOUT NOTICE RECORD KEEPING

The Cooperative shall maintain a record of all terminations of service without notice. This record shall be maintained for a minimum of one ~~(1)~~ year and shall be available for inspection by the ~~Commission~~ACC.

~~362~~355. TERMINATION OF SERVICE WITH NOTICE

The Cooperative may disconnect service to any Customer for any reason stated below, as per the notice requirements set forth in these ~~Rules and Regulations~~RRLEP.

A. Customer violation of any of the Cooperative ~~tariffs~~Tariffs.

B. Failure of the Customer to pay a delinquent bill for electric service.

C. Failure to meet or maintain the Cooperative's deposit requirements.

D. Failure of the Customer to provide the Cooperative reasonable access to its equipment and property.

E. Customer breach of a written contract for service between the Cooperative and Customer.

F. When necessary for the Cooperative to comply with an order of any governmental agency having such jurisdiction.

G. When a hazard exists which is not imminent, but in the opinion of the Cooperative, it may cause personal injury or property damage.

H. When the service installation fails to meet Codes per Section 106. ~~H~~G.

I. Failure by the Customer to pay for damages, caused by the Customer, to the Cooperative's property or personnel.

~~363~~J. Failure of the current occupant to transfer service into his/her name, if there is sufficient evidence that the current account holder is deceased.

356. SERVICE TERMINATION WITH NOTICE RECORD KEEPING

The Cooperative shall maintain a record of all terminations of service with notice. This record shall be maintained for one ~~(1)~~ year and be available for ~~Commission~~ACC inspection.

~~364~~357. TERMINATION NOTICE

The Cooperative shall not terminate electric service to any of its Customers without providing advance written notice to the Customer of its intent to disconnect service, except under those conditions specified where advance written notice is not required.

~~365~~358. ADVANCE WRITTEN NOTICE INFORMATION REQUIRED

Such advance written notice shall contain, at a minimum, the following information:

A. The name of the person whose electric service is to be terminated and the address where service is being rendered

B. An explanation of the violation thereof or the amount of the bill which the Customer has failed to pay in accordance with the payment policy of the Cooperative, if applicable.

C. The date on or after which service may be terminated.

D. A statement advising the Customer to contact the Cooperative's office at 8600 ~~W.~~West Tangerine ~~Rd.~~Road and/or telephone for information regarding any deferred payment or other procedures which the Cooperative may offer or work out some other mutually agreeable solution to avoid termination of the Customer's electric service.

E. A statement advising the Customer that the Cooperative's stated reason for the termination of services may be disputed by contacting the Cooperative at 8600 ~~W.~~West Tangerine ~~Rd.,~~Road, Marana, ~~AZ~~Arizona, and/or telephone advising the Cooperative of the dispute and making arrangements to discuss the cause for termination with a responsible representative of the Cooperative in advance of the scheduled date of termination. The responsible representative shall be empowered to resolve the dispute and the Cooperative shall retain the option to terminate service after affording this opportunity for a meeting and concluding that the reason for termination is just and advising the Customer of his right to file a complaint with the ~~Commission~~ACC.

~~366~~359. THIRD PARTY NOTIFICATION

Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

~~367. RESERVED FOR FUTURE ADDITIONS~~

~~368~~360. TIMING OF TERMINATION WITH NOTICE

The Cooperative shall give at least five ~~(5) days'~~days advance written notice prior to the termination date.

~~369~~361. DELIVERY OF NOTICE OF TERMINATION REQUIREMENT

Such notice shall be considered ~~to be~~ given to the Customer when a copy thereof is left with the Customer or posted first class in the United States mail, addressed to the Customer's last known address.

~~370~~362. SERVICE TERMINATION DATE

If after the period of time allowed by the notice has elapsed and the delinquent account has not been paid nor arrangements made with the Cooperative for the payment thereof, or in the case of a violation of the Cooperative's ~~Rules~~RRLEP the Customer has not satisfied the Cooperative that such violation has ceased, the Cooperative may then terminate service on or after the day specified in the notice without giving further notice.

~~371~~363. SERVICE TERMINATION BY COOPERATIVE

The service may only be disconnected by an authorized representative of the Cooperative, by a means acceptable to the Cooperative.

~~372~~364. RETIREMENT OF FACILITIES

A. Retirement of facilities upon termination of service: The Cooperative shall have the right (but not the obligation) to remove any or all of its property (e.g. electric facilities) installed on the Customer's premises upon the termination of service. Customer's property (e.g. meter pedestal) attached to the Cooperatives property will be left on the Customer's premises unless other arrangements are made. ~~The Cooperative will give proper notice of retirement of facilities as set forth for termination in Sections 368 and 369.~~ If the Customer ~~wishes to have~~requests that electric facilities remain on Customer's premise they shall ~~initiate a request and shall~~ be obligated to pay monthly Customer charges or minimums ~~per~~in accordance with the applicable rate ~~tariff.~~Tariff.

~~373~~B. Retirement of idle facilities: Whenever service is idle for all or part of the time or is in an environment that requires higher than average operating costs the Cooperative shall have the right (but not the obligation) to remove any or all of its property (e.g. electric facilities) installed on the Customer's premises. The Cooperative will give proper notice of retirement of facilities as set forth for termination in Sections 360 and 361. If the Customer requests that electric facilities remain on Customer's premise they shall be obligated to pay monthly Customer charges or minimums in accordance with the applicable rate Tariff.

365. LANDLORD/TENANT RULE

In situations where service is rendered at an address different from the mailing address of the bill or where the ~~Cooperative knows that a landlord/tenant relationship~~Cooperative's Landlord/Tenant Agreement exists and that the landlord is the Customer of the Cooperative, and where the landlord as a Customer would otherwise be subject to disconnection of service, the Cooperative will not disconnect service until the following actions have been taken:

A. Where it is feasible to ~~so~~ provide service, the Cooperative, after providing notice as required in these ~~Rules~~RRLEP, shall offer the occupant the opportunity to subscribe for service in his or her own name. If the occupant then declines to ~~so~~ subscribe, the Cooperative may disconnect service pursuant to the ~~Rules~~RRLEP.

B. The Cooperative will not attempt to recover from a tenant or condition service to a tenant with the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

C. If Trico terminates services to a tenant for non-payment by a tenant, and if a Landlord/Tenant Agreement exists, then the Cooperative will, upon request, reconnect at no charge to the Landlord's name – if the Landlord has no outstanding debts due to the Cooperative.

PART 4. ADMINISTRATIVE AND HEARING REQUIREMENTS

401. INVESTIGATION OF CUSTOMER SERVICE COMPLAINTS

The Cooperative shall make a full and prompt investigation of all service complaints made by its Customers.

402. RESPONSE TIME ON COMPLAINTS

The Cooperative shall respond to the complainant within five ~~(5)~~ working days as to the status of the Cooperative's investigation of the complaint.

403. NOTIFICATION OF COMPLAINT INVESTIGATION FINDINGS

The Cooperative shall notify the complainant of the final disposition of each complaint. Upon request of the complainant, the Cooperative shall report the findings of its investigation in writing.

404. RIGHT OF APPEAL

The Cooperative shall inform the Customer of his right of appeal to the ~~Commission~~ACC.

405. RECORDING REQUIREMENTS OF COMPLAINTS

The Cooperative shall keep a record of all written service complaints received which shall contain, at a minimum, the following data:

A. Name and address of complainant

B. Date and nature of complaint

C. Disposition of the complaint

D. A copy of any correspondence between the Cooperative, the Customer, and/or the ~~Commission~~ACC.

This record shall be maintained for a minimum period of one ~~(1)~~ year and shall be available for inspection by the ~~Commission~~ACC.

~~406. RESERVED FOR FUTURE ADDITIONS~~

~~407.~~406. CUSTOMER BILL DISPUTES

Any Cooperative Customer who disputes a portion of a bill rendered for Cooperative service shall pay the undisputed portion of the bill and notify the Cooperative's designated representative that such unpaid amount is in dispute prior to the delinquent date of the bill.

~~408~~407. COOPERATIVE'S RESPONSIBILITIES ON BILL DISPUTES

Upon receipt of the Customer notice of dispute, the Cooperative shall:

A. Notify the Customer within five ~~(5)~~ working days of the receipt of a written dispute notice.

B. Initiate a prompt investigation as to the source of the dispute.

C. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results. Upon request of the Customer, the Cooperative shall report the results of the investigation in writing.

D. Inform the Customer of his right of appeal to the ~~Commission~~ACC.

~~409~~408. CUSTOMER'S RESPONSIBILITY UPON INVESTIGATION COMPLETION

Once the Customer has received the results of the Cooperative's investigation the Customer shall submit payment within five ~~(5)~~ working days to the Cooperative for any disputed amounts owed to the Cooperative. Failure to make payment shall be grounds for termination of service as outlined in Section ~~362~~355.

~~410~~409. RESOLUTION OF SERVICE AND/OR BILL DISPUTES BY THE ARIZONA CORPORATION COMMISSION

A. In the event a Customer and the Cooperative cannot resolve a service and/or bill dispute, the Customer may file a written statement of dissatisfaction with the ~~Commission~~ACC; by submitting such notice to the ~~Commission~~ACC, the Customer shall be deemed to have filed an informal complaint against the Cooperative.

B. The Cooperative may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ~~Commission~~ACC.

C. The Cooperative shall maintain a record of written statements of dissatisfaction and their resolution for a minimum of one ~~(1)~~ year and make such records available for ~~Commission~~ACC inspection.

Attachment 3

(Payne)

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-______

PRE-FILED DIRECT TESTIMONY

OF REBECCA A. PAYNE

ON BEHALF OF

TRICO ELECTRIC COOPERATIVE, INC.

OCTOBER 23, 2015

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND EMPLOYER.

A. My name is Rebecca A. Payne and I am employed by C.H. Guernsey and Company ("Guernsey").

Q. PLEASE STATE YOUR BUSINESS ADDRESS.

A My business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have earned a Bachelor of Science in Business degree and an M.B.A from Oklahoma City University. I have been employed by Guernsey from 1999-2004, and since 2005. Schedule RAP-1 is my resume.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I represent Trico Electric Cooperative, Inc. ("Trico" or the "Cooperative").

Q. ARE YOU AUTHORIZED TO TESTIFY ON BEHALF OF TRICO?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am sponsoring the schedules that support the adjustments in Section C of the rate filing package, the cost of service schedules set forth in Section G and the proposed rates set forth in Section H.

Q. WERE THE SCHEDULES ABOVE PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. WHO SUPPLIED THE DATA USED IN DEVELOPING THE SCHEDULES THAT YOU ARE SPONSORING?

A. All of the data was supplied by Trico.

Q. WHAT IS THE TEST YEAR IN THIS PROCEEDING?

A. The test year is the twelve months ended December 31, 2014.

II. <u>SCHEDULES AND ADJUSTMENTS</u>

Q. **PLEASE EXPLAIN THE ADJUSTMENT TO PLANT IN SERVICE MADE TO RATE BASE ON SCHEDULE B-2.0.**

A. An adjustment was made to plant in service of $7,824,026 to reflect a transfer of ownership of direct assigned transmission facilities owned by Southwest Transmission Cooperative, Inc. ("SWTC"). Currently the costs associated with the facilities are invoiced by SWTC and included in Trico's purchased power expense. Upon the effective date of the rates in this case as approved by the Arizona Corporation Commission ("ACC"), these facilities will be purchased by Trico from SWTC for $7,824,026, as adjusted, which will increase Trico's plant in service.

Q. PLEASE EXPLAIN SECTION C

A. Schedule C-1.0 is the Income Statement for the test year showing:

- Actual Test Year
- Adjustments to the Test Year
- Adjusted Test Year (Actual Test Year Plus Adjustments)

Adjustments described below correspond to adjustment amounts shown in the "Adjustments" column in the Schedule.

Q. PLEASE EXPLAIN ADJUSTMENTS SHOWN ON SCHEDULE C-1.0.

A. Adjustments are summarized on Schedule C-2.0. Schedules C-2.1 through C-2.5 show adjustments to specific O&M accounts while Schedules C-2.4 through C-2.16 show development of adjustments.

Operating Revenue (Schedule C-2.6). Calculation of revenue shown on this schedule is developed on Schedule E-7.5. This schedule calculates the revenue by applying the existing rates to adjusted test year billing units. The billing units are found on schedules E-7.1 through E-7.2.3. An adjustment was made to adjust the billed consumers to reflect the number of consumers billed derived from the customer charge revenue collected. This adjustment is necessary because, if an account disconnects and connects at the same location within the same billing period, then the consumer count is recorded as two billed consumers for the period; but the customer charge collected is prorated. The billed consumers and kWh sold are also adjusted to show a reclassification of accounts that are moving from the GS3 tariff to the GS4 tariff. The adjustment to the GS4 class also reflects annualized consumption for changes that incurred early in the test year. Lastly, an adjustment was made to normalize the growth in net metered consumers that began late in 2014. The net metering consumers added through 2014 were annualized to identify 12 months of usage from the additional net metering consumers. In addition, since the end of the test year, there was a continued increase in the number of net metering consumers; and the customers with applications received as of the end of February 2015 have been included as an adjustment. The development of the net metering adjustment is shown on Schedule E-7.2.1.

The total adjustment to base revenue is a reduction of $1,296,163.

A revenue adjustment was made to restate the Wholesale Power Cost Adjustment ("WPCA") revenue based on the adjusted power cost summarized on Schedule E-7.7. The adjusted WPCA revenue reflects the full amount of WPCA revenue that Trico is entitled to recover. The WPCA revenue adjustment is $42,073.

The total revenue adjustments result in a decrease to revenue of $122,881.

Other Revenue (Schedule C-2.6.1. An adjustment to the net metering monthly charge revenue was made to reflect the increased number of net metering consumers. The adjustment of $22,000 is the result of the 6,657 additional net metering billing determinants times the net metering tariff charge of $3.38.

Purchased Power (Schedule C-2.7). A detailed calculation of the adjusted purchased power expense is shown on Schedule E-7.7.1. Purchased power was adjusted to include a new purchased power agreement that replaces two previous purchase power agreements that terminated at the end of October 2014, reduction in costs associated with ownership transfer of direct assigned transmission facilities and variable rates as of April 2015 levels. The adjustment to purchased power is an increase of $750,858.

Bad Debt (Schedule C-2.8). An adjustment to Bad Debt expense was made by applying an average bad debt ratio to adjusted test year revenues. The bad debt ratio is developed on Schedule C-2.8.1 and used a five year average of net write-offs as percent of revenue. The adjustment to bad debt expense is an increase of $19,990.

Payroll (Schedule C-2.9). The adjustment to payroll expense totals $221,128. Payroll expense and adjustments are distributed to various expense accounts on Schedule C-2.2. Adjusted payroll was calculated based upon 128 full-time employees and 4 part-time employees using actual 2015 wage levels. The test year ratio for overtime payroll to regular payroll of 4.221% was applied to calculate the total adjusted payroll. The test year ratio for payroll expensed of 61.183% was then applied to calculate adjusted payroll expensed. Historical payroll information is shown on Schedule C-2.9.1. The test year expense by account and distribution of the adjustment by account is shown on Schedule C-2.2

Employee Benefits (Schedule C-2.10). Expenses associated with employee benefits were restated to 2015 levels. The Cooperative's portion of the adjusted test year amount for each benefit was computed and the test year benefits expense ratio (Schedule C-2.9.2) was then applied to calculate the amount of benefits expenses. The test year expense by account and distribution of the adjustment by account is shown on Schedule C-2.3

The adjusted test year premium for medical insurance of $1,058,580 computed by using the cooperative's portion of the 2015 premium for each of the plans for the appropriate number of employees participating (Schedule C-2.10.1). The same methodology was used for the dental plan resulting in an adjusted test year premium of $106,458 (Schedule C-2.10.2). The adjusted test year premium for life insurance of $44,731 was computed by using the adjusted full time base wages rounded up the next $1,000 times the 2015 premium rate (Schedule C-2.10.3). An adjusted test year premium of $78,593 for long-term disability was computed by applying the 2015 premium rate to the adjusted base wages (Schedule C-2.10.4).

The Cooperative's contributions to the defined benefit plan were adjusted to reflect the adjusted base wages and the 2015 contribution rate. The adjusted test year premium for the defined benefit pension plan is $1,645,370 (Schedule C-2.10.5). The 2015 base wages were also used to compute the adjusted amount of 401k contributions of $379,676 (Schedule C-2.10.6).

Rate Case Expense (Schedule C-2.11). An adjustment to recognize expense associated with development, filing and support of the rate case has been made. The estimated cost of $150,000 is intended to reflect cost of outside legal and consulting services. This amount is amortized over a 3-year period, resulting in an adjustment of $50,000. Actual rate case expense will only be known at the time of the hearing or settlement. We propose to provide updated rate case information to ACC Staff and in testimony as the case proceeds.

Depreciation (Schedule C-2.12). A depreciation rate study was prepared by an outside consultant and finalized in July of 2015. The results of the depreciation study confirmed existing depreciation rates of 2.76% for transmission plant and existing depreciation rates of 3.0% for distribution plant accounts with the exception of account 370, meters, are still appropriate. The recommended depreciation rate for account 370 is 6.09%. This shorter life is consistent with useful life of automated meters, which have replaced older technology. This new depreciation rate for meters has been used in computing the adjusted depreciation expense. The depreciation rates were applied to December 31, 2014, plant balances for transmission and distribution plant to determine adjusted depreciation expense for these plant categories. For General Plant accounts, depreciation expense for the month of December 31, 2014 was annualized to determine the adjusted depreciation expense. The adjusted test year depreciation expense of $7,187,533 results in an adjustment of $628,027.

Property Taxes (Schedule C-2.13). The adjusted property taxes were computed by developing an effective tax rate and applying the effective rate to the December 31, 2014 plant balance. The adjustment is an increase of $87,838.

Payroll Taxes (Schedules C-2.14). Adjusted payroll-related taxes for FICA and Federal and State Unemployment were calculated by applying the applicable tax rate to adjusted wages subject to payroll taxes. The test year payroll tax expense ratio of 69.97% (Schedule C-2.9.2) was applied to the total adjusted payroll taxes amount to calculate adjusted payroll taxes expensed. The adjustment is an increase to test year expense of $20,909. The test year expense by account and distribution of the adjustment by account is shown on Schedule C-2.4.

Donations (Schedule C-2.15). An adjustment was made to remove charitable donations totaling $61,200 from the test year. This adjustment results in a reduction to administrative and general expenses of $1,900 and a reduction to other deductions of $59,300.

Interest Expense (Schedule C-2.16). The adjusted interest on long-term debt of $5,088,431 was calculated by applying the applicable interest rates to the principal outstanding as of December 31, 2014 and including a $2.9 million drawn down in March

2015, a $4.5 drawn down in July 2015, a $4 million draw down that will be incurred for the purchase of the direct assignment transmission facilities, and refinancing of RUS 5% debt. The adjustment increased interest on long-term debt expense by $121,844.

Q. ARE THE ADJUSTMENTS THAT HAVE BEEN MADE TO THE TEST YEAR RELATED TO ACTIVITIES THAT ARE KNOWN, MEASURABLE AND OF A CONTINUING NATURE?

A. Yes. The adjustments that have been made are intended to provide an accurate reflection of the Cooperative's known and measurable revenues and expenses on an on-going basis and that should be recovered in rates.

Q. WHAT IS THE OVERALL IMPACT OF THE ADJUSTMENTS MADE TO THE TEST YEAR?

A. The overall impact of the revenue and expense adjustments is to reduce the operating margin by $1,707,787 as reflected in column (b) of Schedule C-1.0. The adjusted test year Operating TIER is 1.57 and the DSC is 2.21.

III. <u>COST OF SERVICE STUDY</u>

Q. WHAT IS THE PURPOSE OF THE COST OF SERVICE STUDY?

A. The cost of service study assigns the plant investment, operating expenses and revenue associated with providing service to each customer class. When the total system revenue requirement has been identified, the assignment of plant investment and operating expenses to each class provides the basis for assigning the revenue requirement to each class. The assignment of the class revenue requirement is generally done based on the class' contribution to the system's overall return or margin. The cost of service study identifies the revenue deficiencies and subsidies that exist between rate classes.

In addition to determining the cost of providing service and the appropriate revenue requirement for each class, the cost of service study also provides important information with regard to the unbundled cost components that comprise the cost to serve. These unbundled cost components can be used to develop rate designs, which more accurately reflect the cost causation, giving the consumer a better price signal with regard to the cost of electric service. The unbundled cost components also provide the necessary information to appropriately price those services, which have been deemed competitive in Arizona. Those services are Metering, Meter Reading and Customer Billing.

Q. HAS THE COST OF SERVICE BEEN DEVELOPED USING A METHODOLOGY THAT HAS BEEN ACCEPTED BY THE COMMISSION?

A. Yes. The cost of service study uses the same program and methodology that has previously been utilized by Trico, as well as used by Navopache Electric Cooperative, Sulphur Springs Valley Electric Cooperative and Mohave Electric Cooperative in their most recent rate filings. The Commission and Commission Staff deemed the methodology to be reasonable and appropriate in each of these prior cases.

Q. PLEASE DESCRIBE THE GENERAL PROCESS INVOLVED IN THE ALLOCATION OF PLANT INVESTMENT AND EXPENSES TO THE VARIOUS CUSTOMER CLASSES.

A. The plant investment and operating expenses are first separated into functional categories such as Transmission Plant, Distribution Plant, Distribution Operations expenses, Customer Accounting Expenses, etc. These plant investment and operating expenses are further classified according to the unbundled cost component that is appropriate. This allows the identification of the make-up of the costs that are being incurred such as Transmission-Demand, Substation-Demand, Purchased Power-Capacity, Purchased Power-Energy, Meter Reading etc.

If a plant investment amount or operating expense can be identified as directly assignable to a particular rate class, then a direct assignment of the investment or expense is made to that class. For all other plant investment and expense amounts that are not directly assignable, an allocation factor based on demand, energy, or number of customers is developed to assign a portion of that investment and expense to the various rate classes. These allocation factors vary based on the type of investment or expense being allocated. For example, transmission plant is considered as totally demand related; therefore, the allocation factor used to assign transmission plant is the twelve month sum of the demand for those classes utilizing the transmission system. The energy component of purchased power is allocated using an allocation factor based on each class' energy (kWh) purchased from the wholesale supplier. Meter reading expenses are considered a customer related cost and are allocated based on a customer allocation factor.

Composite allocation factors are also created as subtotals of various plant accounts and expenses are made within the cost of service study. These composite allocation factors are used to allocate other related plant and expense items. For example, Account 583–Overhead Line Expense is allocated by a subtotal of Account 364/365–Overhead Line Investment, ensuring that the expense is assigned to the same classes as the investment.

Q. PLEASE EXPLAIN THE GENERAL DEVELOPMENT OF THESE ALLOCATION FACTORS?

A. Schedule G-7.1 provides a summary of the initial allocation factors.

Schedule G-7.0 (26 pages) shows the development of the initial allocation factors used in the cost of service study. Additional allocation factors are developed as subtotals in the cost of service study.

Schedule G-7.0, page 1, shows the development of the energy allocation. The appropriate loss factor has been calculated using the energy (kWh) sales information by class and the purchased kWh data. The overall line loss for the system is 5.066447%. The energy allocation factor is used to assign the purchased power energy costs.

The purchased power demand allocation factors are developed on Schedules G-7.0 pages 2 - 3. Allocation Factor #2 on Schedule G-7.0, page 2 of 26 is the demand allocation used to assign costs for the purchased power capacity expense. This allocation factor is based on each class' contribution to the monthly system coincident peak demand. The allocation factor is developed on Schedule I-1.0 with supporting Schedules I-1.1 and I.1.2. Allocation Factor #3 on Schedule G-7.0, Page 6 of 26, is the demand allocation factor used to assign purchased power delivery costs. Allocation factors 4-6 are used for direct assignment of power costs to the GS4 class.

Allocation Factors 7-10 are demand allocation factors based on the class contribution to the Trico Member coincident peak for the assignment of the investment in Transmission Plant, Distribution Substations and Backbone Distribution line in accounts 364 and 365. Schedule I-4.0 provides detail on the development of the investment in backbone investment to be allocated.

Allocation Factor #11 reflects the number of single-phase customers in each class and is used for the allocation of single-phase overhead line investment in accounts 364 and 365.

Supporting Schedules I-3.0 and I-4.0 provide detail on the consumers by class and the development of the investment in single-phase line to be allocated.

Allocation Factor #12 reflects the number of three-phase customers in each class and is used for the allocation of three-phase overhead extension investment in accounts 364 and 365. Supporting Schedules I-3.0 and I-4.0 provide detail on the consumers by class and the development of the investment in three-phase extension.

Allocation Factors 13-16 utilize the average number of customers by rate class and a weighting factor to assign the costs for Meter Reading, Billing and Records and Customer Service activities. The weighting factors represent the relative cost to perform those activities for each rate class.

Allocation Factor #17 is used to assign the customer related investment associated with account 368 – Transformers. The supporting Schedule I-7.0 shows the development of these allocation factors. Allocation Factor #18 is for a direct assignment of transformers. Allocation Factor #19 shows the average number of consumers by class and a weighting factor for each class reflecting the relative cost for each class of providing the investment in account 369 – Services.

Allocation Factor #20 shows the average number of customers by class and the average cost of providing a meter for each class. This factor is used to assign the investment in account 370 – Meters.

Allocation Factor #21 provides a direct allocation for investment and costs related to security lighting.

Allocation Factor #22 provides the assignment of adjusted test year base revenue to each rate class.

Allocation Factor #23 provides the assignment of the adjusted test year WPCA revenue.

Allocation Factor #24 is based on the average number of customers and is used to assign other revenue.

Allocation Factor #25 for the direct assignment of wheeling revenue to the wheeling class.

Allocation Factor #26 is used to assign the demand-related investment associated with account 368 – Transformers. The supporting Schedule I-7.0 shows the development of these allocation factors.

Q. PLEASE DESCRIBE THE COST OF SERVICE ALLOCATION SCHEDULES IN SECTION G.

A. Provided in Section G are the cost of service allocation schedules showing the allocations to the rate classes.

Schedule G-3.1 shows the allocation of plant investment to the customer classes. The first column indicates the test year plant balance. The second column indicates the allocation factor used and the remaining columns show the allocated amount to each class of customer.

Schedule G-4.0, shows the allocation of operating expenses by account to the customer classes. The allocation of expenses generally follows the allocation of plant investment.

The transmission O&M expenses are all allocated by the subtotal of transmission plant. The various distribution O&M accounts are allocated in a manner consistent with the allocation of the plant account or activity to which the expense is associated. For example, the overhead line expense in Account 583 is allocated based on the sum of Accounts 364/365. Schedule G-4.1 shows the allocation of the payroll expenses by account to the customer classes. The allocation of payroll is necessary to develop the allocation factors used to assign the General Plant investment and administrative and general expenses.

Schedule G-4.2shows the allocation of interest expense to the customer classes.

Schedule G-4.3is the allocation of revenues to the customer classes. The base revenue and WPCA revenue allocated to each rate class are the adjusted test year revenues developed in Section E.

Q. PLEASE DESCRIBE THE UNBUNDLED COST COMPONENT SCHEDULES.

A. Schedule G-5.0 shows the components of rate base allocated to each of the rate classes.

Schedule G-5.0 shows the components of plant allocated to each of the rate classes.

Schedules G-6.0, Page 1 – 4, is the summary of the components of expense allocated to each of the rate classes. Schedule G-6.0, Page 1, shows a consolidation of the components of expense into the four major cost categories for the rate classes. The total customer related cost of providing distribution service to the Residential class reflected on this schedule is $31.83 per customer per month. This represents the customer related costs that Trico incurs to provide distribution wires service to the customer exclusive of any transmission, generation. capacity or energy costs.

Schedules G-6.1, Page 1 – 10, is the detail of the components of expense allocation to each of the rate classes.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COST OF SERVICE STUDY.

A. Schedule G-1.0 shows the results of the cost of service study under the existing rates for the rate classes. This schedule shows the allocated rate base, operating revenues, operating expenses, resulting return, interest, resulting operating margin, and the calculated revenue deficiencies for each rate class. Schedule G-2.0 is the summary of the cost of service study under proposed rates for the rate classes.

The revenue requirement for each class under the proposed rates was determined based on the magnitude of the rate change indicated by the cost of service and the impact of the proposed rate change upon the class.

The rates proposed in the filing reflect Trico's consideration of these criteria. The rate of return on rate base has been calculated for the total Trico system and for each of the rate classes in the cost of service study to be used as a measure of each rate class' ability to recover costs in comparison with the total system. The proposed rates are generally designed to move the individual class rates of return closer to the system average where possible. The relative rate of return provides a measure of how each class' rate of return changes under the proposed rates. The following table summarizes the relative rate of return under existing rates for each rate class on Schedule G-1.0 and the relative rate of return under proposed rates as shown on Schedule G-2.0.

	Existing RROR	Proposed RROR
Residential	0.706	0.836
Residential TOU	0.070	0.562
GS 1	0.808	0.874
GS 2	0.228	0.571
GS 3	3.952	2.598
GS TOU	3.203	2.615
GS 4	2.391	1.928
Water Pumping	-0.332	0.279
Irrigation	-4.265	-3.189
ToD Pumping	-3.517	-2.558
Interruptible	1.279	1.349
Lighting	-2.923	-2.201
Total System	1.000	1.000

As indicated by the table, the relative rates of return under proposed rates move closer to 1.000 for indicating a movement toward rates which more closely reflect cost.

IV. RATE DESIGN AND IMPACT ON CUSTOMERS

Q. WHAT ARE THE BASIC OBJECTIVES OF THE PROPOSED RATE DESIGN FOR EACH CLASS?

A. The basic objectives of the proposed rate design are:

- Reflect an appropriate recovery of the cost of providing service;
- Reflect the unbundled costs of providing service; and
- Reflect a consideration of the impact of the rate change on the member

Q. WHAT ARE THE PROPOSED REVENUE CHANGES FOR EACH CLASS?

A. The proposed rate change for each rate class is shown on Schedule H-1.0. The proposed unbundled rate design for each rate class is shown on Schedule H-2.1. The proposed base cost used in the calculation of the proposed WPCA is shown on Schedule H-2.1.1. The calculation of the proposed WPCA is shown on Schedule H-2.1.2.

Q. PLEASE DESCRIBE THE PROPOSED RATE FOR RESIDENTIAL.

A. The proposed rate for the residential class results in an increase revenue requirement of 4.11%. The base customer charge is increased from $15.00 to $20.00 per month. The customer component of expense associated with the distribution wires for the residential class as reflected on Schedule G-6.0, page 1, is actually $31.83 per month. The customer component of expense reflects Trico's cost of having the service available before any energy is actually sold to the customer. Costs included in the customer component include the customer component of distribution line expense, a portion of the transformer expense, the meter and service drop expense, meter reading and customer records expense. The increase in the customer charge moves rates closer to, but still significantly less than the actual customer component costs.

The energy charge is changing from a flat kWh charge to an inclining block rate with two blocks, the first 800 kWh per month at one charge and all excess kWh per month at a charge that is $0.01 per-kWh higher. The proposed inclining block rate will provide a stronger signal for energy efficiency and conservation measures. This allows moderation of the rate change impact on lower use consumers.

The comparison of the existing and proposed residential rate is shown on Schedule H-3.0. As a result of the increase in the customer charge, members with low usage see a higher percentage increase. Consumers with higher usage will also see increases higher than those closer to the class average.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR RESIDENTIAL TIME OF USE.

A. The proposed rate increase residential time of use class is 7.88%. The rates of return shown on Schedule G-1.0 show the residential time of use class is underperforming the standard residential class and a large increase is necessary to move closer to the system-average rate of return. This is due in part to the fact that since the residential time of use rate was implemented, Arizona Electric Power Cooperative, Inc. ("AEPCO") now charges Trico fixed capacity charges versus a monthly demand charge. There is no longer a direct cost savings for Trico Members to lower consumption during peak periods, although Trico continues to see cost savings from SWTC for any reduction in monthly peak demand related to the transmission monthly demand charge. Trico also recognizes that there continues to be long-term benefits to the Cooperative and its members by reducing demand, hence reducing capacity requirements and lowering costs.

The customer charge component of the rate is increasing from $19.00 to $25.00. The structure of the on-peak and off-peak kWh charges remains unchanged, in order to continue to send a pricing signal to reduce consumption during peak periods.

The comparison of the existing and proposed residential rate is shown on Schedule H-4.1. As a result of the increase in the customer charge, members with low usage see a higher percentage increase.

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN FOR GS 1.

A. The GS1 rate applies to commercial, business, professional and various sized non-residential loads less than 10 kW. The proposed rate increase for the GS1 class is 4.19%.

The Customer Charge is increased from $18.00 to $23.00 for single phase and from $26.00 to $31.00 for three phase, and a very small increase in the energy (kWh) charge.

The billing comparison for the GS1 customers is shown on Schedule H-4.2.

Q. PLEASE DESCRIBE THE PROPOSED GENERAL SERVICE 2 RATE.

A. The GS2 rate applies for non-residential load requirements greater than 10 kW but less than 200 kW with a load factor of 30% or less. The proposed change for the GS2 class is an increase of5.02%. The customer charge is increased from $18.00 to $23.00 for single phase and from $26.00 to $31.00 for three phase and a small increase in the kWh charge.

The billing comparison for the GS2 customers is shown on Schedule H-4.3.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO THE GS 3 RATE.

A. The GS3 rate is for non-residential loads from 10 kW to 11,999 kW. The proposed change to the GS3 rate class is a reduction of 3.99%. Because the consumers served on this rate have higher load factors and are able to use the system more efficiently, this class is earning a relative rate of return significantly higher than the system average.

The customer charge increases from $18.00 to $23.00 for single phase and $26.00 to $31.00 for three phase. The demand charge increases from $16.65 to $18.00 and the kWh charge is reduced to $0.0749.

The billing comparison for GS3 is on Schedule H-4.4. The impact of the rate change reflects a larger percentage reduction for higher load factor consumers.

Q. PLEASE DESCRIBE THE PROPOSED WATER PUMPING RATE DESIGN.

A. The change to water pumping class is an increase of 7.28%. This class would need over a 17% increase to earn the system average rate of return. The increase of 7.28% moderates the customer impact and moves the relative rate of return closer to the system average. The customer charge increases $5.00 for both the single and three phase rates and the kWh charge is set at $0.1435.

The billing comparison for Water Pumping is on Schedule H-4.6.

Q. PLEASE DESCRIBE THE PROPOSED IRRIGATION RATE DESIGN.

A. The change to irrigation class is an increase of 7.28%. Due to seasonality of irrigation load this class would need over a 100% increase to earn the system average rate of return. The increase of 7.21% moderates the customer impact while moving in the necessary direction. The customer charge increases $5.00 for both the single and three phase rates and the kWh charge is set at $0.13.

The billing comparison for Irrigation is on Schedule H-4.7.

Q. PLEASE DESCRIBE THE PROPOSED TIME OF DAY PUMPING RATE DESIGN.

A. The change to the time of day pumping class is an increase of 3.83%. The customer charge increases $5.00 for both the single and three phase rates. The existing rate has a wholesale power on peak demand charge only. The proposed rate adds a new customer peak demand charge of $1.75 and lowers the wholesale on-peak demand charge from $18.16 to $16.00. The implementation of the customer peak demand charge prevents consumers from avoiding all the demand charges. There is a potential for transmission-related cost savings from reducing peak demand load but the system demand cost component to serve the consumers is not eliminated and should not be avoided.

The time of day pumping billing comparison is on Schedule H-4.8.

Q. PLEASE DESCRIBE THE PROPOSED INTERRUPTIBLE COMMERCIAL AND PUMPING RATE DESIGNS.

A. Currently there is a separate tariff for the Interruptible Commercial class and Interruptible Pumping class but the charges are the same on both tariffs. Trico is proposing to combine the two tariffs into one tariff and freeze it so that no new customers will be served under this tariff. Over time, to the extent possible with the limitations of customer impact, Trico seeks to eliminate this tariff and move all the existing customers served under this tariff to an applicable tariff. In order to do that, Trico has made changes to the proposed rate, in order to make the transition easier. There is no change to the customer charge. There is a proposed new customer peak demand charge and a reduction in the wholesale on-peak demand charge.

The Interruptible billing comparison is on Schedule H-4.9.

Q. HAVE ALL OF THE RATE DESIGNS BEEN REVISED TO REFLECT THE NEW BASE POWER COST IN THE WHOLESALE POWER COST ADJUSTMENT?

A. Yes. Each proposed rate design reflects the proposed wholesale power cost adjustment calculated using the new base power cost of $0.081711 per kWh sold.

Q. WHAT ARE THE PROPOSED CHANGES TO THE WHOLESALE POWER COST ADJUSTMENT?

A. The WPCA has been revised to reflect recovery of the total adjusted purchased power cost. The proposed base rates have been designed to recover the appropriate level of costs for each rate class in conjunction with the application of the revised WPCA. Schedule H-2.1.1 provides the calculation of the adjusted WPCA.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Minnesota

- Agralite Electric Cooperative, Benson

Missouri

- Platte-Clay Electric Cooperative, Kearney

Nebraska

- Dawson County PPD, Lexington

Oklahoma

- Caddo Electric Cooperative, Binger
- Central Rural Electric Cooperative, Stillwater
- Cimarron Electric Cooperative, Kingfisher
- Cookson Hills Electric Cooperative, Stigler
- Cotton Electric Cooperative, Walters
- City of Ponca City
- Lake Region Electric Cooperative, Hulbert
- Rural Electric Cooperative, Lindsay
- Tri-County Electric Cooperative, Hooker

Texas

- Bailey County ECA, Muleshoe
- Bandera Electric Cooperative, Bandera
- Bluebonnet Electric Cooperative, Giddings
- Cooke County ECA, Muenster
- Deaf Smith Electric Cooperative, Hereford
- Grayson-Collin Electric Cooperative, Van Alstyne
- Guadalupe Valley Electric Cooperative, Gonzales
- Jackson Electric Cooperative, Edna
- Karnes Electric Cooperative, Karnes City
- Magic Valley Electric Cooperative, Mercedes
- Medina Electric Cooperative, Hondo
- North Plains Electric Cooperative, Perryton
- Nueces Electric Cooperative, Robstown
- South Plains Electric Cooperative, Lubbock
- Southwest Texas Electric Cooperative, El Dorado
- Swisher Electric Cooperative, Tulia
- Taylor Electric Cooperative, Merkel
- Tri-County Electric Cooperative, Azle
- Trinity Valley Electric Cooperative, Kaufman
- United Cooperative Services, Cleburne
- Victoria Electric Cooperative, Victoria
- Wise Electric Cooperative, Decatur

Wyoming

- Powder River Energy Corporation, Sundance
- Wyrulec Company, Lingle

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Publications and Presentations:

"Knowledge is Power: Financial Forecasting" has been presented yearly in GUERNSEY's offices in Oklahoma City since 2006. Ms. Payne has assisted as a presenter for this seminar numerous times.

"Knowledge is Power: Understanding Rates and Cost of Service" has been presented several times each year since 2005, at GUERNSEY's offices in Oklahoma City as well as in other locations. Ms. Payne has been a presenter for this seminar.

EXPERIENCE RECORD:

1999-Present – Consultant, C. H. Guernsey & Company, Oklahoma City, Okla.
1999-2004 – Consultant, Analytical Solutions Group

2004-2005 – Video Professor, Inc., Lakewood, Colo.

Ms. Payne worked as a Financial Analyst providing information to upper management to aid in making business decisions. She prepared and monitored reports on key elements of the business model to identify problem areas. She assisted in budget preparation for multiple business segments and maintained updated forecasts to monitor deviations from the budget. She also provided financial viability analysis that helped measure success of marketing projects.

Attachment 4

(Hedrick)

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TRICO ELECTRIC COOPERATIVE, INC., AN ARIZONA NONPROFIT CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF IT UTILITY PLANT AND PROPERTY AND FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PLANT AND PROPERTIES AND FOR RELATED APPROVALS.	DOCKET NO. E-01461A-15-______

PRE-FILED DIRECT TESTIMONY OF DAVID HEDRICK

ON BEHALF OF

TRICO ELECTRIC COOPERATIVE, INC.

OCTOBER 23, 2015

INDEX TO TESTIMONY OF DAVID W. HEDRICK

TOPIC **Page**

EXHIBITS

BACKGROUND AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David W. Hedrick and my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Guernsey Engineers, Architects and Consultants. I am Senior Vice-President and Manager of the Analytical Services group.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have earned a Bachelor of Science degree from the University of Central Oklahoma in mathematics and a M.B.A degree from Oklahoma City University. I have been employed with Guernsey since 1981. My primary area of responsibility is rate analysis and cost of service work for electric distribution cooperatives and electric generation/transmission cooperatives. Attached hereto as Exhibit DWH-1 is my resume with a listing of the projects and clients with which I have been involved.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE REGULATORY COMMISSIONS?

A. Yes. I have testified before the Arizona Corporation Commission, the Arkansas Public Service Commission, the Colorado Corporation Commission, the Oklahoma Corporation Commission, the Public Utility Commission of Texas and the Wyoming Public Service Commission.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A. I am testifying on behalf of Trico Electric Cooperative, Inc. ("Trico" or the "Cooperative").

Q. ARE YOU AUTHORIZED TO TESTIFY ON BEHALF OF TRICO?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony will provide the following:

a. A discussion of Trico's objectives in this filing and an overview of the rate filing package;
b. A discussion of the development of the revenue requirement for Trico;
c. A discussion of the impact of distributed generation and net metering on the Cooperative and the development of the proposed new net metering tariff;
d. A discussion of the impact of Trico's purchase of direct assignment facilities from Southwest Transmission Cooperative, Inc. (SWTC); and
e. A discussion of the proposed change in the Rules, Regulations and Line Extension Policy (RRLEP);

TRICO OBJECTIVES AND OVERVIEW OF RATE FILING

Q. WHAT ARE TRICO'S OBJECTIVES IN THIS FILING?

A. Trico's objectives in this filing are:

a. To increase the total system revenue requirement by $2,182,076 which is a 2.49% increase. The proposed increase will provide an adequate revenue requirement that recovers the adjusted test year level of expenses and provides a margin that will allow the Cooperative to meet its financial objectives with regard to equity, capital credit retirements and cash levels;

b. Revise the Net Metering Tariff for all new distributed generation (DG) members (applications received on or after March 1, 2015) which will eliminate the banking of member generated kWh and compensate the DG member for all excess energy produced at Trico's avoided cost rate. Existing Net Metered members (with completed applications prior to March 1, 2015) will continue to be served on Trico's existing Net Metering Tariff.

c. Incorporate the effect of the purchase of SWTC direct assignment facilities on Trico's revenue requirement and rates.

d. Revise the existing RRLEP to reflect an allowable investment by Trico for new Residential members of $1,500 plus the cost of special equipment. Additional revisions are proposed for the line extension allowable investment for subdivisions and other members.

e. Revise the rate design for various rate classes to reflect the cost to serve:

    a. Increase the customer charge in the Residential rate and include an inclining block energy rate;

    b. Reduce the overall rate for the GS3 rate class based on the cost to serve; and

    c. Combine the existing two Interruptible rates into one rate class and discontinue offering of this rate to new customers.

Q. HAS THE BOARD OF DIRECTORS OF TRICO APPROVED THIS RATE FILING BASED ON THESE OBJECTIVES?

A. Yes. The Trico Board of Directors approved the filing of the rate case at its meeting on September 22, 2015.

Q. DOES THIS RATE FILING MEET THE REQUIREMENTS AS SET FORTH IN THE COMMISSION'S RULES?

A. Trico believes this filing is in compliance with the requirements in A.A.C. R14-2-103 for Class A electric utilities and contains the required schedules and data necessary for the Commission's review and approval of the proposed rates. In addition to its docketed application ("Application"), Trico will be providing Commission Staff with its work papers and information in electronic form on a flash drive in conjunction with this filing. While not required by Commission rule, Trico understands such information, when provided, facilitates Staff's review of the Application. Trico intends to cooperate with Staff throughout the processing of this Application and hopes an expedited and fair final determination can be obtained at a reasonable cost to Trico and its members.

Q. WERE THE SCHEDULES THAT ARE INCLUDED AS <u>ATTACHMENT 5</u> TO TRICO'S RATE APPLICATION PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. WHAT IS THE TEST YEAR IN THIS RATE FILING?

A. The test year is the twelve months ending December 31, 2014.

Q. WHAT ADJUSTMENTS HAVE BEEN PROPOSED TO THE TEST YEAR?

A. Trico witness Rebecca Payne discusses the development of the adjustments to the test year in her testimony which is attached as Attachment 3 to the Application. The adjustments to revenue, operating expenses and interest expense are for changes that are known, measurable and of a continuing nature. The intent was to include those adjustments which would accurately reflect Trico's operations on a going forward basis that are reasonable and consistent with the standard rate making process at the Commission.

Q. ARE THERE ANY OUTSTANDING COMPLIANCE ISSUES OF WHICH TRICO IS AWARE?

A. No.

DEVELOPMENT OF REVENUE REQUIREMENT

Q. WHAT REVENUE REQUIREMENT IS TRICO PROPOSING?

A. The proposed total system revenue requirement is $89,662,812 as reflected on Schedule A-2.0 to Attachment 5 of Trico's Application. The proposed total system increase necessary to achieve this revenue requirement is $2,182,076 or 2.49% over the adjusted test year revenue. The fair value rate base is $175,076,536 as reflected on Schedule B-2.0 to Attachment 5 of Trico's Application.

Q. HOW WAS THE TOTAL SYSTEM PROPOSED REVENUE REQUIREMENT DETERMINED?

A. As a member-owned electric cooperative, Trico's revenue requirement is a function of the margins and cash necessary to meet the financial objectives set forth by the Board of Directors. These financial objectives are set in terms of the equity level, the cash general funds level, the capital credit retirement program and the coverage ratios required by the Cooperative's lenders. The Board of Directors has approved the proposed rate changes in this filing which are sufficient to recover the adjusted test year level of expenses and provide margins that achieve the following objectives:

- Grow equity as a percent of assets to the 40%-50% range with projected total system plant additions averaging $12,229,007 per year over the next five years.
- Allow the cooperative's cash position to decline slightly to an amount that is approximately 3% of total plant in service.
- Maintain capital credit retirements of $1,500,000 per year.
- Maintain adequate Times Interest Earned Ratios (TIER) and Debt Service Coverage Ratios (DSC).

The financial analysis indicates the proposed rate increase amount will allow Trico to meet the Board's objectives as set forth above.

Q. PLEASE DESCRIBE THE FINANCIAL ANALYSIS SUPPORTING THE OVERALL SYSTEM RATE CHANGE AND REVENUE REQUIREMENT?

A. Attached to my testimony are exhibits comprising the financial analysis:

- Exhibit DWH-2 shows the system capitalization and the equity as a percent of assets for the test year and the previous five years. The equity has grown from 27.68% in 2009 to 39.79% at the end of the test year. The financial objective of the board is to grow the equity to a level of 40%-50%.
- Exhibit DWH-3 shows the historical and projected plant additions. The plant additions for the next five years are projected to average $12,229,007 per year. This amount reflects the capital additions that will need to be financed through a combination of debt and retained earnings.
- Exhibit DWH-4 shows the capital credits retired since 2004. In accordance with Board policy, Trico projects capital credit retirements of approximately $1,500,000 per year.
- Exhibit DWH-5 shows the calculation of desired general funds. The major components making up the annual cash requirement are listed as well as the total plant balance. The estimated general funds at the end of the test year was $8,523,672 which was equivalent to 41.12 days of cash and 3.65% of plant. Trico believes that an adequate level of cash would be an amount approximately 3% of total plant which will produce roughly 30 days of cash.
- Exhibit DWH-6 is the ratio summary page from the ten-year financial forecast which includes the proposed rate increase effective January 1, 2017. The equity as a percent of assets is projected to increase from the 39.79% level at the end of 2014 to 45.499% in 2020. The Modified TIER is projected to improve to 2.17 with the rate increase effective in 2017 and be maintained at or below this level during the forecast period.

- Exhibit DWH-7 is the pro forma income statement from the ten year financial forecast case. The forecast reflects that the operating margin is projected to decline slightly from $4,614,142 in 2014 to $4,592,573 in 2016. With the proposed rate increase effective in 2017, the operating margin is projected to increase to $5,364,759. The forecast case identifies when additional rate increases will be needed to maintain a minimum Modified DSC at a level of 1.85. The forecast indicates that additional rate revenue will not be required until 2022.
- The complete financial forecast is provided in Section J.
- Schedule A-2.0 of Attachment 5 to the Application shows that the proposed increase will produce an operating margin of $5,088,431 based on the adjusted test year data. This produces an Operating TIER of 2.00. The results of the financial forecast case reflected in Exhibit DWH-6 and DWH-7 indicates that with the proposed increase effective in 2017, Trico's equity as a percent of assets will increase to a level that meets the board's equity objective, cash levels will decline to the 3% of total plant level and be maintained at that level and capital credits of $1,500,000 per year will be retired. The forecast indicates that with the proposed rates, Trico will not need another rate change until roughly 2022.

Q. IS THE PROPOSED RATE INCREASE REASONABLE?

A. Yes. The proposed increase will allow Trico to meet its financial objectives and maintain its financial integrity. The increase is a modest 2.49% overall increase which mitigates the impact on members. Trico believes that the proposed increase strikes the correct balance between maintaining the financial health of the Cooperative and limiting the impact on members.

THE IMPACT OF DG AND NET METERING ISSUES'

Q. PLEASE DESCRIBE THE IMPACT THAT DISTRIBUTED GENERATION INSTALLED BY MEMBER CONSUMERS HAS ON THE COOPERATIVE AND ITS MEMBERS.

A. The rapid growth in solar distributed generation installed by individual residential consumers has caused Trico to assess the impact such installations have on the Cooperative's ability to recover the costs of providing service and the subsidies that are created between customers.

The Cooperative delivers electric service to its members using an extensive distribution system. This distribution system consists of electric facilities built to serve the total capacity of the electric load and customer-specific electric facilities that are required to provide service regardless of how much energy is consumed. The capacity-related facilities include substations, a portion of the overhead and underground line and a portion of the transformer. The customer-related facilities include a portion of the overhead and underground line, a portion of the transformer, the service line and the meter. The costs of providing service associated with both the demand and customer-related facilities are fixed in nature. That is, these costs do not vary based on the amount of energy (kWh) consumed.

In addition to the fixed distribution costs of providing service, the Cooperative also incurs fixed wholesale capacity costs to provide electric service to its members from its wholesale power suppliers. These costs are associated with existing generation and transmission facilities that ensure the ability to provide continuous service to members. These fixed costs do not vary and are represented in a fixed charge billed by the wholesale supplier.

Historically, Trico and other similar cooperatives have recovered the costs of providing service to residential members through rates with a monthly service availability charge (or customer charge) and an energy charge applied to the monthly kWh consumption. The monthly service availability charge approved by the Arizona Corporation Commission has historically been an amount that was well below the total justifiable customer-related cost of providing service per customer. The energy charge has historically been designed to recover the remainder of costs to provide service not included in the service availability charge which includes a portion of the customer related costs, all of the fixed distribution demand costs, the fixed wholesale demand costs and the variable energy costs. This structure of Residential rate design is common among utilities. This rate design recovers a major portion of the fixed costs in the variable component of the rate. This rate design has functioned well historically for the recovery of costs where all of the customers being served in the Residential rate class were similar consuming entities that did not operate solar distributed generation facilities. However, this rate design does not provide for the appropriate recovery of the costs to provide service to customers that have solar distributed generation facilities.

A customer that installs distributed generation facilities will reduce the energy (kWh) that is purchased from the Cooperative by an amount equal to the generation output of their facility. This reduction in kWh purchased from the cooperative results in a loss of fixed costs being recovered through the energy component of the rate. The fixed distribution demand and customer costs that the Cooperative incurs to provide service are similar for all Residential customers whether they have distributed generation or not. These fixed distribution demand and customer costs incurred by the Cooperative are not reduced as a result of the installation of distributed generation. Yet, because of the existing rate structure and the reduction in kWh purchased by the customer, the fixed costs recovered in the energy component of the rate are not recovered. The existing rate structure was not designed to appropriately recover the costs of providing service from a member with distributed generation. If this situation with the recovery of costs is not addressed, then the lost fixed costs from customers with distributed generation eventually is recognized as a cost to be recovered from all of the remaining customers with consumption. The result is that customers with distributed generation do not pay the appropriate fixed demand and customer costs for the provision of electric service while the remainder of customers pay more than their equitable share of those costs. Without addressing the rate issue, the installation of distributed generation shifts costs from one group of customers to another.

Q. ARE MEMBERS WITH DISTRIBUTED GENERATION CONTINUING TO UTILIZE THE GRID FOR SERVICE?

A. Yes. Members may claim that since their net power flow is zero that they are not using the grid, but this is simply not true. First of all, those with DG systems don't produce power all of the time. When they are producing in excess of their own needs the excess energy is put back on the grid. When the excess energy is put back on the grid, Trico must use it immediately – Trico has no storage capability. The member also needs somewhere to push its excess energy – most solar PV systems do not adjust to meet on-site demand. However, under the current Net Metering Tariff the Trico system serves essentially as a "financial battery" to store full retail rate credits that can be used at some unknown point in the future to cover the retail cost of energy when the DG customer is not producing power sufficient to meet its load requirement. Moreover, it is important to understand that the grid provides much more than power. The grid services that Trico and other utilities provide include reliability, reserves, frequency control, voltage control, and redundancy as physical quantities flowing through the grid. Members may have net zero power flows but reliability is flowing into the member and none is flowing out: not a net zero. Voltage control is flowing into the member and none is flowing out: not a net zero. Frequency control is consumed by the member and none is provided by the member: not a net zero. In short, while members may have reached a "net zero" threshold on energy (kWh), they are a large net negative on very expensive grid services that everyone else has to pay for. Stating that you don't use the grid because you are net zero is like saying, "I drive the same road to and from work each day so I net zero mileage on the road and therefore I don't use the road."

Q. WHAT IMPACT DOES THE EXISTING NET METERING POLICY HAVE ON THE COOPERATIVE?

A. Trico's existing Net Metering Tariff is based on the requirements set forth in Arizona Administrative Code ("A.A.C.") R14-2-2306 (Net Metering Policy), which provides as follows:

> A. On a monthly basis, the Net Metering Customer shall be billed or credited based upon the rates applicable under the Customer's currently effective standard rate schedule and any appropriate rider schedules.
>
> B. The billing period for Net Metering will be the same as the billing period under the Customer's applicable standard rate schedule.
>
> C. If the kWh supplied by the Electric Utility exceed the kWh that are generated by the Net Metering Facility and delivered back to the Electric Utility during the billing period, the Customer shall be billed for the net kWh supplied by the Electric Utility in accordance with the rates and charges under the Customer's standard rate schedule.
>
> D. If the electricity generated by the Net Metering Customer exceeds the electricity supplied by the Electric Utility in the billing period, the Customer shall be credited during the next billing period for the excess kWh generated. That is, the excess kWh during the billing period will be used to reduce the kWh supplied (not kW or kVA demand or customer charges) and billed by the Electric Utility during the following billing period.
>
> E. Customers taking service under time-of-use rates who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit during the next billing period during the on- or off-

peak periods corresponding to the on- or off-peak periods in which the kWh were generated by the Customer.

F. Once each calendar year the Electric Utility shall issue a check or billing credit to the Net Metering Customer for the balance of any credit due in excess of amounts owed by the Customer to the Electric Utility. The payment for any remaining credits shall be at the Electric Utility's Avoided Cost. That Avoided Cost shall be clearly identified in the Electric Utility's Net Metering tariff.

A member with installed distributed generation reduces the energy (kWh) purchased from the Cooperative and thereby causes lost fixed costs to be incurred. The existing Net Metering Policy exacerbates the loss of fixed costs and creates a significant subsidy by requiring the Cooperative to pay the full retail rate for energy generated by the member, even though the retail rate far exceeds the value of the excess generation. The Cooperative's Avoided Cost rate is the appropriate value for compensation of the excess generation. This over-compensation for the DG energy produced by the net metered customer becomes a cost for all members of the Cooperative to pay. The application of the Net Metering Policy in its current form is not equitable.

Q. WHAT IS THE MAGNITUDE OF THE LOST FIXED COST THAT RESULTS FROM SERVICE PROVIDED TO MEMBERS WITH DISTRIBUTED GENERATION?

A. Exhibit DWH-8 provides a calculation of the lost fixed cost resulting from service provided to Residential members with distributed generation under three scenarios:

1. The existing rate with the existing Net Metering Policy
2. The proposed rate with the existing Net Metering Policy
3. The proposed rate with the proposed Net Metering Policy partial waiver

The energy charge in both the existing and proposed Residential rate has been separated into three cost components: purchased power and transmission demand costs, purchased power energy costs and distribution wires costs. The purchased power and transmission demand costs and distribution wires costs are fixed costs that do not vary based on kWh consumption and are not reduced as a result of the reduced consumption even though these costs are recovered in the energy charge of the rate. Therefore, as energy consumption is reduced due to installed DG, these fixed costs are no longer recovered from these consumers. These costs not recovered from members with distributed generation are defined as lost fixed costs.

As of March 1, 2015, Trico had 1,262 Residential members with distributed generation. The average size of the Residential DG system installed is 6.51 kW (AC) with an average monthly production of 922 kWh. The provisions of the existing net metering policy establish that the total generation output from a DG unit up to the level of the member's consumption be compensated to the consumer by the cooperative at the full retail rate.

Under the existing Residential rate and existing Net Metering Tariff the monthly lost fixed purchased power and transmission demand costs is $45.57 per customer. The monthly lost fixed distribution wires costs is $37.77 per customer. The total monthly lost fixed cost is $83.34 per customer. The estimated lost fixed costs for the 1,262 Residential DG customers for an annual period under the existing residential rate is $1,262,079. This amount represents the annual fixed cost component of revenue lost as a result of member owned distributed generation. This loss of revenue represents more than 50% of the total proposed revenue requirement increase.

Q. HOW IS TRICO PROPOSING TO ADDRESS THE ISSUE OF LOST FIXED COST AND SUBSIDIES CREATED FROM SERVING DG CUSTOMERS?

A. To address this issue, Trico is proposing the following:

1. To increase the monthly service availability (or customer) charge in the standard Residential rate from $15.00 to $20.00. This change allows for a greater recovery of fixed customer related costs through the fixed charge and thus helps to reduce subsidies between members within the rate class.
2. Introduce a new Net Metering Tariff that compensates new distributed generation customers at the avoided cost rate for all distributed generation energy produced in excess of the DG customer's load. New distributed generation customers will continue to be able to offset their instantaneous load with their distributed generation energy.
3. Revise the existing Net Metering Tariff to be applicable to those net metered customers that Trico received applications after midnight February 28, 2015. Existing net metered customers (those with applications received before midnight February 28, 2015) will continue on the existing Net Metering Tariff and be eligible to receive full retail rate compensation for all excess distributed generation energy.

Q. WHAT IMPACT DO THE PROPOSED RESIDENTIAL RATE AND REVISED NET METERING TARIFF FOR NEW DG CUSTOMERS HAVE ON THE LOST FIXED COST RECOVERY?

A. The proposed Residential rate provides a more equitable recovery of distribution costs and the revised Net Metering Tariff for new DG customers significantly reduces the lost fixed cost by establishing a cost-based level of compensation for the energy (kWh) produced by a member's distributed generation resource for energy in excess of the DG customers load.

The middle column of Exhibit DWH-8 shows the calculation of the lost fixed costs associated with member-owned distributed generation under the proposed Residential rate with the existing Net Metering tariff. The analysis shows that the lost fixed costs actually increase slightly under the proposed Residential rate in comparison to the lost fixed costs under the existing Residential rate. Although the customer charge has been increased in the proposed rate, the inclining block energy charge causes the energy charge for the kWh in excess of 800 per month to be higher. The result is a slightly higher lost fixed cost recovery under this scenario. The lost fixed cost recovery will remain a significant issue for existing net metered customers under the proposed rate and the existing Net Metering tariff.

The third column of Exhibit DWH-8 shows the calculation of the lost fixed costs associated with member-owned DG under the proposed Residential rate with the proposed Net Metering tariff for new DG members. Under the proposed Net Metering Tariff for new DG members, the DG member will continue to be able to utilize their member owned generation to offset their actual load. However, there will be no banking of kWh therefore all excess generation will be compensated at Trico's avoided cost rate. This significantly reduces the number of kWh generated by the member's DG unit that will be compensated at the full retail rate and consequently the level of lost fixed costs. Under the existing Net Metering tariff, the estimated monthly kWh produced by the average DG unit and compensated at the full retail rate is 922 kWh. Under the proposed Net Metering tariff, the estimated monthly kWh compensated at the full retail rate will be reduced to 397 kWh. The monthly lost fixed cost recovery from the average DG customer is reduced from $83.34 per customer per month under the existing Net Metering tariff and existing rates to $38.38 per customer per month under the proposed Net Metering tariff and proposed rates. For comparison purposes, the total dollar amount of lost fixed costs for the total number of Residential DG customers as of March 1, 2015 has been calculated under the proposed Net Metering tariff. The analysis shows that the level of lost fixed costs is significantly reduced under the proposed Net Metering tariff.

Q. WHAT IS TRICO'S POSITION WITH RESPECT TO THE PROVISION OF RENEWABLE ENERGY?

A. Trico is a strong supporter of renewable energy. Trico has had in place a renewable energy program since 2005 and an approved Renewable Energy Standard and Tariff ("REST) plan since the Commission's REST rules became effective.

Q. ARE THE ISSUES RELATED TO DG CUSTOMERS INCLUDED IN THIS FILING UNIQUE TO TRICO?

A. No. The problem of utility lost revenues to recover fixed costs due to net metering is not a new or unprecedented problem exclusive to Trico. The Commission has also recognized the existence of the cost-shift burden in Decision No. 74202 (December 2013) involving Arizona Public Service Company's application to approve its solution to the net metering cost-shift dilemma. Specifically, the Commission found in Finding of Fact 49 of that decision that the growth of DG systems in APS' service territory "results in a cost shift from APS's DG Customers to APS's non DG residential Customers absent significant changes to APS's rate design." For APS, the Commission approved a temporary fix of a \$0.70 per kW charge to APS's DG customers through its Lost Fixed Cost Recovery mechanism ("LFCR") to deal with what the Commission saw as "simply unfair for DG customers to contribute less to the recovery of APS's annual LFCR revenue than non-DG customers do."

Q. ARE THE ISSUES RELATED TO DG CUSTOMERS LIMITED ONLY TO ARIZONA?

A. No. The issues related to DG customers and net metering are being addressed across the country. Other state regulatory bodies have developed laws and orders pertaining to the cost issues that are informative. For example, attached as Exhibit DWH-11 is legislation that was passed in Oklahoma that requires utilities in the state to eliminate subsidies to customers with distributed generation. Specifically, the law states:

C. No retail electric supplier shall allow customers with distributed generation *installed after the effective date of this act to be subsidized by customers in the same class of service who do not have distributed generation.*

D. *A higher fixed charge for customers within the same class of service that have distributed generation installed after the effective date of this act, as compared to the fixed charges of those customers who do not have distributed generation, is a means to avoid subsidization between customers within that class of service and shall be deemed in the public interest.*

Exhibit DWH-12 is legislation that was passed in Arkansas to amend the requirements for utilities to compensate net metering customers. Section 3 of the act directs the Arkansas Public Service Commission to establish rates, terms and conditions for net-metering contracts, including:

(A)(i) A requirement that the rates charged to each net-metering customer recover the electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers.

(ii) The electric utility's entire cost of providing service to each net metering customer within each of the electric utility's class of customers under subdivision (b)(1)(A)(i) of this section:

(a) Includes without limitation any quantifiable additional cost associated with the net-metering customer's use of the electric utility's capacity, distribution system, or transmission system and any effect on the electric utility's reliability; and

(b) Is net of any quantifiable benefits associated with the interconnection with and providing service to the net-metering customer, including without limitation benefits to the electric utility's capacity, distribution

system or transmission system.

In addition to the legislation passed in Oklahoma and Arkansas, the Wisconsin Public Service Commission has also recently provided comment on DG subsidies. On page 62 of the Order in Docket No. 05-DR-107 (December 23, 2014), the commission states:

> *As Wisconsin courts have long recognized, rate design is a quintessential legislative function firmly left to the discretion of the Commission. Other substantial state and federal programs are designed specifically to support the development and implementation of conservation and renewable energy resources. The Commission is not required to use rate design as a hidden subsidy for these resources. This Commission continues to support customers who want to own their own generation; however, the Commission also has an obligation to those customers who do not want to or who cannot afford to own generation to make sure these customers are not subsidizing the costs for those who choose to and are able to own their own generation.*

Q. WHAT ADDITIONAL INFORMATION HAVE YOU PROVIDED FOR CONSIDERATION WITH REGARD TO THE COST RECOVERY ISSUE FOR DG CUSTOMERS?

A. Attached as Exhibit DWH-13 is an article from the December 2014 Electricity Journal entitled "Valuation of Distributed Solar: A Qualitative View."[1] The article was written by Mr. Ashley Brown, the Executive Director of the Harvard Electricity Policy Group, former Commissioner of the Ohio Public Utility Commission and former chairman of NARUC, and Jillian Bunyan, a previous

[1] 1040-6190/© 2014 Elsevier Inc. All rights reserved., http://dx.doi.org/10.1016/j.tej.2014.11.005

attorney for the United States Environmental Protection Agency's Office of Regional Counsel. The preface to the article provides insight regarding the content of the article:

> *A critical evaluation of the arguments used by solar DG advocates shows that those arguments may often overvalue solar DG. It is time to reassess the value of solar DG from production to dispatch and to calibrate our pricing policies to make certain that our efforts are equitable and carrying us in the right direction.*

All of the examples of legislation, commission orders and the Electricity Journal article confirm the understanding that there are significant cost recovery issues with the provision of service to customers with installed distributed generation and the current use of net metering is not an effective or equitable means to compensate customers for that distributed generation. The proposed Residential DG rate along with the proposed change in the net metering tariff provide an effective, equitable and balanced method to reduce the lost fixed cost recovery from new DG members.

PROPOSED CHANGES IN THE RULES, REGULATIONS AND LINE EXTENSION POLICY

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO TRICO'S RRLEP.

A. Trico's existing line extension policy was approved in Decision No. 71230 of Docket No. E-01461A-08-0430 in 2009. Excerpts from items 64 and 65 in the order provide the basis for the changes made at that time:

"64. Staff agrees with Trico's proposal to eliminate free footage for line extensions and believes the change will improve the Cooperative's ability to recover the costs associated with the anticipated continuation of above-average growth in the Trico's service area...

65. ... The elimination of the free footage for line extensions, as conditioned by Staff's recommendations, is fair and equitable and conforms to recent Commission decisions for other utilities."

The revisions to Trico's RRLEP approved by the commission in 2009 were recommended by Commission Staff and supported by the Commissioners for the purpose of ensuring recovery of costs related to high growth. Several of the utilities in the state had been granted similar treatment for line extensions prior to the approval of Trico's rate filing.

Economic conditions have changed in Arizona since 2009. System growth has slowed significantly with Trico experiencing less than a 1.9% annual increase in the number of residential consumers since 2010. The concern regarding the recovery of costs related to high growth are no longer an issue and the rates for service that Trico charges are sufficient to allow for the provision of a modest allowable investment to provide service to a new customer.

Trico is proposing a line extension allowable for permanent Residential customers of $1,500 plus the cost of special equipment. Special equipment includes the transformer and meter. The cost of special equipment for the average new Residential member is estimated at $500. The total allowable investment for a permanent Residential customer would therefore be roughly $2,000. The maximum allowable investment supported by the proposed Residential rate for the average customer of $2,833 has been calculated on Exhibit DWH – 9 over a 35 year period of a permanent residence. The maximum allowable investment for a new member connect is determined based on the annual proposed distribution wires revenue produced for the average consumption consumer and the costs of providing service identified in the cost of service study. The maximum allowable investment does not include the cost to the Cooperative to construct any new backbone/system facilities to support new members. Exhibit DWH – 9.1 is a support schedule for Exhibit DWH -9.0 showing the calculation of the operating costs as a percentage of plant investment and the average allocated current system plant investment from the cost of service study.

Trico has proposed the allowable investment for permanent Residential member connects that is slightly lower than the maximum allowable amount justified so as not to create undue pressure on rates and as a consideration of the investment in new system facilities needed to support new members. Trico believes that the proposed line extension allowable provides a fair, equitable and balanced approach.

Q. WHAT IS THE PROJECTED IMPACT OF THE PROPOSED CHANGE IN THE LINE EXTENSION ALLOWABLE?

A. There is no immediate impact or adjustment affecting the adjusted test year operating expenses. The impact comes in the form of new plant additions to connect new members in future years and the associated capital costs associated with those additions. The additional plant required for new Residential connects would include an amount up to $2,000 per connect. Based on historical data, Trico has determined that the average construction cost for a new Residential connect over a twelve month period is less than $1,400 per connect. Trico estimates that the total additional plant additions that will result from the change in the line extension policy will be roughly $1.3 million per year.

Q. IS TRICO PROPOSING TO REVISE THE LINE EXTENSION ALLOWABLE FOR RATE CLASSES OTHER THAN RESIDENTIAL?

A. Yes. Trico proposes no line extension allowable for its GS3 and GS4 rate classes. However, Trico proposes to provide a line extension allowable investment for all other rate classes (other than Residential, GS3 and GS4) based on a formula applied to each individual customer similar to the calculation for Residential shown on Exhibit DWH – 9.

Each non-permanent Residential member would receive an allowable investment equal to the Cooperative's equipment and labor cost to install the special equipment (transformer and meter)..

In addition, Trico is proposing to revise the RRLEP for a duly recorded subdivision development to provide an allowable investment equal to the Cooperative's equipment and labor cost to install the transformers within the subdivision.

DIRECT ASSIGNMENT FACILITIES

Q. PLEASE DESCRIBE THE IMPACT OF TRICO'S PURCHASE OF THE DIRECT ASSIGNMENT FACILITIES?

A. As reflected in the testimony of Karen Cathers, Trico has approved the purchase of certain direct assignment facilities from SWTC used to deliver wholesale transmission service to Trico. Upon the effective date of the rates in this case as approved by the Arizona Corporation Commission (ACC), the facilities will be purchased by Trico from SWTC for the purpose of reducing the overall cost to Trico's members. Exhibit DWH – 10 provides a comparison of the annual operating costs associated with the direct assignment facilities as operated by SWTC and after the purchase by Trico. Trico projects that the purchase of the direct assignment facilities will result in an overall reduction in cost of $163,410 per year. The known and measurable reduction in purchased power costs associated with the purchase of the direct assignment facilities has been recognized in the adjustments to the test year operating expenses. The increase in fixed costs incurred by TRICO related to the direct assignment facilities have also been recognized in the adjustments to the test year operating expenses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

guernsey | ENGINEERS ARCHITECTS CONSULTANTS

EDUCATION:

M.B.A., Oklahoma City University, 1993
B.S., Mathematics, University of Central Oklahoma, 1986

PERTINENT EXPERIENCE FOR THE PROJECT:

Mr. Hedrick specializes in the development of revenue requirements, cost of service, rate design, line extension analysis, special contract development, pole attachment rates, valuation analysis and other financial analysis for electric, water, and wastewater utility systems. He is also responsible for the preparation of rate filings and has presented expert testimony before state regulators, including Arizona, Arkansas, Colorado, Oklahoma, Texas and Wyoming. Mr. Hedrick's clients include both distribution providers and wholesale providers. He was instrumental in the development of the CoOPTIONS: family of computer software for use in unbundled utility cost of service studies and financial forecasting.

As Manager of the Analytical Solutions Group, Mr. Hedrick has oversight of all studies, analyses and filings that are developed by the group. He continues to represent clients before the appropriate regulatory authority and is responsible for the preparation of rate filings and other analytical studies.

SPECIFIC CONSULTING EXPERIENCE:

Acquisitions, Consolidations & Valuation Analysis

Mr. Hedrick has provided analytical support for consolidation studies in Texas and Wyoming. In addition, he has been involved in the valuation analysis of utility assets for purposes of acquisition and determination of fair market value for clients in Oklahoma and Kansas.

Retail Rate Analysis, Cost of Service Studies, and Line Extension Analysis

Mr. Hedrick's rate analysis and cost of service experience includes the following:

Arizona

- Navopache Electric Cooperative, Inc. - Regulated by Arizona Corporation Commission
- Sulphur Springs Valley Electric Cooperative, Inc. - Regulated by Arizona Corporation Comm.
- Trico Electric Cooperative, Inc. - Regulated by Arizona Corporation Commission

Arkansas

- Arkansas Valley Electric Cooperative Corporation - Regulated by Arkansas PSC and Oklahoma Corporation Commission
- Ouachita Electric Cooperative Corporation - Regulated by Arkansas PSC
- Ozarks Electric Cooperative Corporation - Regulated by Arkansas PSC

Colorado

- Colorado Rural Electric Association
- Delta-Montrose Electric Association
- Empire Electric Association, Inc.
- Grand Valley Rural Power Lines
- Holy Cross Electric Association, Inc.
- Mountain Parks Electric, Inc.
- Poudre Valley REA, Inc.
- San Luis Valley Rural Electric Cooperative, Inc.
- Yampa Valley Electric Association, Inc.

Iowa

- Corn Belt Power Cooperative
- Iowa Lakes Electric Cooperative, Inc.
- Midland Power Cooperative, Inc.

Kansas

- Ark Valley Electric Cooperative Association
- Caney Valley Electric Cooperative Association
- CMS Electric Cooperative, Inc.
- Flint Hills Rural Electric Cooperative Association
- Kansas Electric Power Cooperative
- Lyon-Coffey Electric Cooperative, Inc.
- City of Meade
- Ninnescah Rural Electric Cooperative Association, Inc.
- Pioneer Electric Cooperative, Inc.
- Sedgwick County Electric Cooperative Association, Inc.
- Western Cooperative Electric Association, Inc.

Louisiana

- Claiborne Electric Cooperative

Mississippi

- Southern Pine EPA
- Yazoo Valley EPA

Nebraska

- Dawson County Public Power District

New Mexico

- Farmers Electric Cooperative, Inc.
- Lea County Electric Cooperative, Inc.

Oklahoma

- City of Blackwell
- Caddo Electric Cooperative
- Central Rural Electric Cooperative, Inc.

- Choctaw Electric Cooperative, Inc.
- Cimarron Electric Cooperative, Inc.
- Cookson Hills Electric Cooperative, Inc.
- Cotton Electric Cooperative, Inc.
- City of Duncan
- East Central Oklahoma Electric Cooperative
- Indian Electric Cooperative, Inc.
- Kay Electric Cooperative, Inc.
- Kiwash Electric Cooperative, Inc.
- Lake Region Electric Cooperative, Inc.
- City of Mangum
- Northeast Oklahoma Electric Cooperative, Inc.
- Northfork Electric Cooperative
- Northwestern Electric Cooperative, Inc.
- Oklahoma Electric Cooperative, Inc.
- City of Ponca City
- Rural Electric Cooperative, Inc.
- Southeastern Electric Cooperative, Inc.
- Southwest Rural Electric Association
- Tri-County Electric Cooperative, Inc.
- Verdigris Valley Electric Cooperative

Texas

- Bailey County ECA
- Bandera Electric Cooperative, Inc.
- Big Country Electric Cooperative, Inc.
- Bluebonnet Electric Cooperative, Inc.
- Central Texas Electric Cooperative, Inc.
- Concho Valley Electric Cooperative, Inc.
- Cooke County Electric Cooperative Assn.
- CoServ Electric
- Deaf Smith Electric Cooperative, Inc.
- Fannin County Electric Cooperative, Inc.
- Farmers Electric Cooperative, Inc.
- Fort Belknap Electric Cooperative, Inc.
- Grayson-Collin Electric Cooperative, Inc.
- Greenbelt Electric Cooperative, Inc.
- HILCO Electric Cooperative, Inc.
- Jackson Electric Cooperative, Inc.
- Lamar County Electric Cooperative, Inc.
- Lighthouse Electric Cooperative, Inc.
- Lyntegar Electric Cooperative, Inc.
- Magic Valley Electric Cooperative, Inc.
- Medina Electric Cooperative, Inc.
- Navarro County Electric Cooperative, Inc.
- Navasota Valley Electric Cooperative, Inc.
- North Plains Electric Cooperative, Inc.
- Nueces Electric Cooperative, Inc.
- Pedernales Electric Cooperative, Inc.

- Rita Blanca Electric Cooperative, Inc.
- San Bernard Electric Cooperative, Inc.
- South Plains Electric Cooperative, Inc.
- Southwest Rural Electric Association, Inc., Okla.
- Southwest Texas Electric Cooperative, Inc.
- Swisher Electric Cooperative, Inc.
- Taylor Electric Cooperative, Inc.
- Texas Electric Cooperatives, Inc., Statewide Association
- Tri-County Electric Cooperative, Inc.
- Trinity Valley Electric Cooperative, Inc.
- United Cooperative Services
- Wharton County Electric Cooperative, Inc.
- Wise Electric Cooperative, Inc.

Wyoming

- Big Horn REC - Regulated by Wyoming Public Service Commission until 2007
- Carbon Power & Light, Inc. - Regulated by Wyoming Public Service Commission until 2007
- High Plains Power, Inc. - Regulated by Wyoming Public Service Commission until 2007
- Powder River Energy Corporation - Regulated by Wyoming Public Service Commission
- Wyrulec Company - Regulated by Wyoming Public Service Commission until 2007

Wholesale Rate Analysis and Cost of Service Studies

- Corn Belt Power Cooperative, Humboldt, Iowa
- Kansas Electric Power Cooperative, Topeka, Kansas
- Grand River Dam Authority, Vinita, Oklahoma
- Oklahoma Municipal Power Authority, Edmond, Oklahoma
- Western Farmers Electric Cooperative, Anadarko, Oklahoma
- Central Electric Power Cooperative, Columbia, South Carolina
- Piedmont Municipal Power Authority, Greer, South Carolina
- Brazos Electric Cooperative, Waco, Texas
- Golden Spread Electric Cooperative, Amarillo, Texas
- Old Dominion Electric Cooperative, Richmond, Virginia
- Allegheny Electric Cooperative, Harrisburg, Pennsylvania
- South Mississippi Electric Power Association, Hattiesburg, Mississippi
- Minnkota Power Cooperative, Grand Forks, North Dakota
- Rayburn Country Electric Cooperative, Rockwall, Texas

Special Projects

Development of Distributed Generation Procedures and Guidelines Manual:

- Western Farmers Electric Cooperative, Anadarko, Oklahoma
- KAMO Electric, Vinita, Oklahoma
- Texas Electric Cooperatives, Austin, Texas

Energy Policy Act of 2005 / EISA 2007 - Testimony in Support of Cooperative Staff's Position in Consideration of new PURPA Standards:

- Central Rural Electric Cooperative, Stillwater, Oklahoma
- Cotton Electric Cooperative, Walters, Oklahoma
- Farmers Electric Cooperative, Greenville, Texas
- Grand River Dam Authority, Vinita, Oklahoma
- Grayson-Collin Electric Cooperative, Van Alstyne, Texas
- HILCO Electric Cooperative, Itasca, Texas
- Lake Region Electric Cooperative, Hulbert, Oklahoma
- Lyntegar Electric Cooperative, Tahoka, Texas
- Magic Valley Electric Cooperative, Mercedes, Texas
- Northwestern Electric Cooperative, Woodward, Oklahoma
- Oklahoma Electric Cooperative, Norman, Oklahoma
- Tri-County Electric Cooperative, Azle, Texas
- Tri-County Electric Cooperative, Hooker, Oklahoma
- United Electric Co-op Services, Cleburne, Texas

Testimony before Colorado State House and Senate Committees in support of the Colorado Rural Electrification Association with regard to HB1169, Mandating Net Metering for Electric Cooperatives.

The "Fresh Look" review of East Kentucky Power Cooperative on behalf of the cooperative's distribution members as required by the Kentucky Corporation Commission. 2011 - 2012

Education and Training

Mr. Hedrick provides educational seminars and training for cooperative staff and boards of directors, statewide associations, and professional organizations on the topics of Rate Analysis, Cost of Service, Rate Design, Line Extension Policy, and related issues.

Expert Witness

Mr. Hedrick has provided expert testimony related to the development of revenue requirements, cost of service, rate design, and special contract issues in Arizona, Arkansas, Oklahoma, Texas, and Wyoming.

Financial Forecasting & Analysis

Mr. Hedrick prepares and provides training in the development of financial forecast models for electric cooperatives and municipal utility systems.

Software Sales & Support

Mr. Hedrick provided assistance in the development of software for GUERNSEY's 10-year Financial Forecast, Cost of Service, and Financial Performance Analysis programs. Mr. Hedrick is proficient in the use of these software packages and provides support to client users.

Strategic Planning & Analysis

Mr. Hedrick has provided assistance to electric cooperative boards of directors in the development of strategic goals and objectives.

Publications and Presentations:

Articles:

Hedrick, David W. "Retail Rate Development: The Role of the Cooperative Board." *Management Quarterly*, published by NRECA's Education and Training Department. (Spring 2005): 20-35.

Presentations Made by Mr. Hedrick:

"Knowledge is Power: Financial Forecasting." Seminar written and presented by Guernsey personnel annually since 2006 in Oklahoma City, Okla. Mr. Hedrick has been a presenter for this seminar numerous times.

"Knowledge is Power: Understanding Rates and Cost of Service." Seminar written and presented by Guernsey personnel annually since 2005, in Oklahoma City, Okla., as well as other locations. Mr. Hedrick has been a presenter numerous times.

"Distributed Generation Net Metering Issues." Written for and presented at *TEC Engineers Association Annual Meeting.* September 2006.

"Net Metering Issues." Written for and presented at *G&T Planners Association Meeting,* Tucson. Arizona, September 2006.

"Development of Distributed Generation Policies and Procedures." Written and presented for *Texas Electric Cooperatives' Managers Meeting.* San Antonio, Texas, December 2, 2004.

"Rate Design in a Restructured Environment." Written and presented for *Texas Electric Cooperatives Accountants Association*. Austin, Texas, April 19, 2000.

EXPERIENCE RECORD:

1981-Present – C. H. Guernsey & Company, Oklahoma City, Oklahoma

2013 – Senior Vice President, Board of Directors
2008-2013 – Vice President for Guernsey
2005-Present – Manager, Analytical Solutions Group

TRICO ELECTRIC COOPERATIVE, INC.

SYSTEM CAPITALIZATION

	2009	2010	2011	2012	2013	Test Year 12/31/2014
Long-Term Debt	$ 130,299,238	$ 127,415,993	$ 126,333,910	$ 123,044,808	$ 123,874,418	$ 119,145,770
Equity	56,567,316	61,702,887	67,093,814	73,624,201	81,020,265	89,420,496
Total Capitalization	$ 186,866,554	$ 189,118,880	$ 193,427,724	$ 196,669,009	$ 204,894,683	$ 208,566,266
Percent Capitalization						
Long-Term Debt	69.73%	67.37%	65.31%	62.56%	60.46%	57.13%
Equity	30.27%	32.63%	34.69%	37.44%	39.54%	42.87%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Total Assets	$ 204,349,513	$ 206,644,048	$ 210,398,339	$ 212,359,494	$ 221,056,491	$ 224,707,078
Equity as % of Total Assets	27.68%	29.86%	31.89%	34.67%	36.65%	39.79%
Calculation of Distribution System Equity Only						
G&T Patronage Included in Equity	$ 20,366,123	$ 22,723,790	$ 25,677,740	$ 27,605,172	$ 30,649,835	$ 35,048,077
Total Equity Excluding G&T Patronage	$ 36,201,193	$ 38,979,097	$ 41,416,074	$ 46,019,029	$ 50,370,430	$ 54,372,419
Equity as % of Assets Excluding G&T	17.72%	18.86%	19.68%	21.67%	22.79%	24.20%

TRICO ELECTRIC COOPERATIVE, INC.

GROWTH RATE IN NET PLANT

	Additions	Retirements	Utility Plant	Accum. Deprec.	Net Plant	Percent Change
December 31, 2004	$ 11,410,371	$ 938,942	$ 137,873,827	$ 28,008,458	$ 109,865,369	
December 31, 2005	15,407,838	1,192,621	152,089,045	30,792,753	121,296,292	10.40%
December 31, 2006	22,478,109	1,690,570	172,876,584	33,442,012	139,434,572	14.95%
December 31, 2007	22,946,245	3,243,055	192,579,774	35,593,925	156,985,849	12.59%
December 31, 2008	9,763,604	1,236,302	201,107,076	40,426,392	160,680,684	2.35%
December 31, 2009	10,328,839	1,582,349	209,853,566	44,918,003	164,935,563	2.65%
December 31, 2010	7,934,408	2,786,391	215,001,583	48,781,471	166,220,112	0.78%
December 31, 2011	8,395,120	2,508,916	220,887,787	53,450,701	167,437,086	0.73%
December 31, 2012	6,172,843	2,044,413	225,016,217	58,590,962	166,425,255	-0.60%
December 31, 2013	6,874,618	1,580,392	230,310,443	64,337,090	165,973,353	-0.27%
December 31, 2014	6,735,250	3,512,401	233,533,292	68,137,427	165,395,865	-0.35%
Compound Growth 2004-2014						4.18%
Compound Growth 2009-2014						0.06%
Compound Growth 2011-2014						-0.41%
Projected 12/31/2015	$ 10,837,729	$ 1,195,569	$ 243,175,452	$ 74,407,344	$ 168,768,108	2.04%
Projected 12/31/2016	9,270,063	1,341,489	251,104,026	80,774,749	170,329,277	0.93%
Projected 12/31/2017	18,642,796	1,515,882	268,230,940	87,493,557	180,737,383	6.11%
Projected 12/31/2018	11,067,212	1,712,947	277,585,205	94,302,476	183,282,729	1.41%
Projected 12/31/2019	11,327,234	1,637,201	287,275,238	101,484,625	185,790,613	1.37%
Total	$ 61,145,034	$ 7,403,088				
Compound Growth 2013-2016						3.00%
Compound Growth 2013-2018						2.35%

TRICO ELECTRIC COOPERATIVE, INC.

CAPITAL CREDITS RETIRED

	General	Special	Total
2004	$ 451,452	$ 44,130	$ 495,582
2005	77,096	35,304	112,400
2006	368,068	24,928	392,996
2007	631,726	46,682	678,408
2008	0	40,154	40,154
2009	0	6,747	6,747
2010	993,554	10,241	1,003,795
2011	1,499,955	21,224	1,521,179
2012	1,500,000	23,147	1,523,147
2013	1,654,564	72,097	1,726,661
2014	1,500,000	81,780	1,581,780
Total	$ 8,676,415	$ 406,434	$ 9,082,849

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF DESIRED GENERAL FUNDS

Purchased Power	$ 52,362,485
Payroll	9,914,930
Benefits	3,313,409
Payroll Taxes	751,040
Interest	5,088,431
Principal Payments	4,222,676
Total	$ 75,652,971
Plant Balance	$ 233,533,293

Desired General Funds:	**Days**	**Ratio to Plant**	**Amount**
	30	2.66%	$6,218,052
	45	3.99%	$9,327,079
	60	5.33%	$12,436,105
	90	7.99%	$18,654,157
*Estimated General Funds as of December 31, 2014	41.12	3.65%	$8,523,672

TRICO ELECTRIC COOPERATIVE, INC.
Rate Case - 2014 LOAD FORECAST adj, 2015 BUDGET
LOW GROW,O&M EXP +5%,LineExt,mod DEPR,purch DAF
Ratio Summary

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Equity as Percent of Total Assets	34.669	36.651	39.794	40.165	41.843	41.938	43.167	44.349	45.499	46.587	46.110	47.131	47.904
Equity as Percent of Capitalization	37.246	39.160	42.366	42.681	44.474	44.462	45.736	46.958	48.147	49.271	48.654	49.710	50.504
Debt Service				1.86290	1.86284	1.99653	1.93177	1.90810	1.88045	1.89904	1.86024	1.86004	1.85999
Times Interest Earned Ratio	2.40772	2.76350	3.00237	2.03534	2.04680	2.19485	2.12533	2.12406	2.11621	2.10112	2.03042	2.00558	1.88916
Average Revenue per kWh Sold	11.92694	13.16282	12.97807	12.40259	12.62459	12.85414	13.86386	13.96146	14.05984	14.15799	14.30365	14.44279	14.49082
Percent Increase in Average Revenue		10.362	-1.403	-4.434	1.789	1.818	7.855	0.704	0.704	0.698	1.028	0.972	0.332
Total Utility Plant per kWh Sold	34.03576	34.81193	34.77468	34.98466	35.17994	36.56483	36.81673	37.06977	37.30630	37.52839	38.69844	38.86647	39.02276
Net General Funds to Total Utility Plant	3.25269	3.91701	3.71733	4.63120	3.39659	2.99999	3.00000	2.99999	2.99999	3.00000	3.00000	3.00000	2.99999
Accum Depreciation to Total Utility	26.03855	27.93494	29.17675	30.42821	31.83321	32.33547	33.72872	35.12111	36.47915	37.80886	38.21623	39.56491	40.88530
Operations & Maint Cost per Consumer	204.71	225.65	231.48	245.51	251.28	261.78	267.58	273.54	279.65	285.92	292.36	298.96	305.73
Admin & General Cost per Consumer	127.56	124.64	146.23	134.68	137.85	141.09	144.41	147.80	151.28	154.83	158.47	162.19	166.01
Plant Revenue Ratio	6.43618	6.55566	6.58202	6.74001	6.67861	6.60322	6.64183	6.67965	6.71461	6.74690	6.89303	6.86738	6.95214
Rate of Return on Rate Base	6.96765	6.51028	5.85111	5.37595	5.54141	5.68870	5.55612	5.41941	5.27621	5.12678	4.84300	4.86634	4.48409
Rate Base (RBF times Net Utility Plant)	164,761,003	164,313,622	163,741,907	167,489,691	169,457,857	179,682,218	182,119,667	184,517,152	186,877,683	189,199,817	199,250,687	201,243,530	203,194,267
Rate Base Factor (RBF) Percent	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000	99.00000
% Inc. Over Present Retail Rates Req				0.00000	0.29692	0.00000	0.00000	0.00000	0.00000	0.00000	0.33637	0.62536	0.23789
Modified Debt Service Coverage				1.80148	1.85000	1.98403	1.91975	1.89672	1.86961	1.88837	1.85000	1.85000	1.85000
Modified TIER	2.05305	2.12241	1.99210	1.92025	2.02222	2.17039	2.10133	2.10060	2.09313	2.07825	2.00809	1.98376	1.86762
Rotation Cycle in Years				59.61	61.95	64.30	67.17	69.90	72.59	75.22	77.77	80.19	82.63
Percent Change in Net Plant		-0.27	-0.34	2.28	1.17	6.03	1.35	1.31	1.27	1.24	5.31	1.00	0.96

Exhibit DWH - 6

TRICO ELECTRIC COOPERATIVE, INC.
Rate Case - 2014 LOAD FORECAST adj, 2015 BUDGET
LOW GROW,O&M EXP +5%,LineExt,mod DEPR,purch DAF
Pro Forma Income Statement

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Accrual Basis													
Revenue from Present Rates	78,851,081	87,083,256	87,155,687	86,209,399	89,833,179	94,294,942	104,528,609	108,195,500	111,996,439	115,930,836	120,020,568	124,254,315	128,642,655
Add'l Revenue Required	0	0	0	0	277,418	0	0	0	0	0	384,197	735,240	287,905
Total Required Revenue	78,851,081	87,083,256	87,155,687	86,209,399	90,110,598	94,294,942	104,528,609	108,195,500	111,996,439	115,930,836	120,404,765	124,989,556	128,930,560
Cost of Power	43,889,938	51,951,765	51,675,225	50,130,033	52,512,370	53,673,716	62,735,167	65,188,003	67,739,126	70,384,624	73,146,254	76,010,999	78,989,022
Gross Margin	34,961,143	35,131,491	35,480,462	36,079,366	37,598,227	40,621,225	41,793,442	43,007,496	44,257,313	45,546,212	47,258,511	48,978,557	49,941,538
Operations and Maint Expense	8,375,032	9,446,220	9,961,594	10,811,428	11,351,999	12,132,319	12,722,130	13,341,919	13,993,171	14,677,444	15,396,377	16,151,690	16,945,190
Consumer Accounts and Sales	3,380,021	3,266,945	3,085,540	3,280,559	3,346,170	3,413,093	3,481,355	3,550,982	3,622,002	3,694,442	3,768,331	3,843,698	3,920,572
Admin and Gen and Other Deductions	5,218,682	5,217,961	6,293,090	5,931,128	6,227,684	6,539,068	6,866,021	7,209,322	7,569,788	7,948,277	8,345,691	8,762,976	9,201,125
Depreciation and Amort Expense	6,507,489	6,503,112	6,559,506	7,052,088	7,282,016	8,315,159	8,605,141	8,905,532	9,212,291	9,526,179	10,098,386	10,426,998	10,763,227
Tax Expense	-62	-38	3	0	0	0	0	0	0	0	0	0	0
Amort Deferred Debits (Non Cash)	0	0	0	0	0	0	0	0	0	0	0	0	0
Amort Deferred Credits (Non Cash)	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Expense	5,713,480	5,154,823	4,966,587	4,847,482	4,797,783	4,856,827	4,971,339	4,920,296	4,875,126	4,837,097	4,985,507	5,123,535	5,082,065
Interest - Other	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Operating Expenses	73,084,580	81,540,788	82,541,545	82,052,719	85,518,024	88,930,182	99,381,154	103,116,055	107,011,504	111,068,064	115,740,547	120,319,896	124,901,202
Operating Margin	5,766,501	5,542,468	4,614,142	4,156,680	4,592,573	5,364,759	5,147,454	5,079,445	4,984,934	4,862,772	4,664,218	4,669,659	4,029,358
Nonoperating Margins	250,112	243,408	313,224	304,252	311,858	319,654	327,645	335,836	344,232	352,838	361,659	370,700	379,968
G&T and Other Capital Credits	2,026,384	3,304,655	5,017,623	557,864	117,925	118,780	119,325	115,434	112,514	110,649	111,329	111,767	109,483
Net Margin	8,042,997	9,090,531	9,944,989	5,018,796	5,022,357	5,803,194	5,594,425	5,530,715	5,441,681	5,326,259	5,137,206	5,152,127	4,518,810
Cash Basis													
Operating Cash Before Debt Service				16,360,503	16,984,232	18,856,399	19,051,581	19,241,109	19,416,584	19,578,887	20,109,771	20,590,893	20,254,619
Total Debt Service				9,081,691	9,180,666	9,504,055	9,923,966	10,144,365	10,385,312	10,368,117	10,870,146	11,130,212	10,948,442
Cash Margins After Debt Service				7,278,812	7,803,566	9,352,344	9,127,614	9,096,744	9,031,272	9,210,769	9,239,624	9,460,680	9,306,176

Exhibit DWH -7

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF LOST FIXED COST RECOVERY
AS A RESULT OF MEMBER OWNED DISTRIBUTED GENERATION SERVED ON THE RESIDENTIAL RATE

		Existing Rate	Proposed Rate Existing NM Tariff	Proposed Rate Proposed NM Tariff
Energy Charge (Includes WPCA)		$ 0.121161	$ 0.127600	$ 0.127600
Purchased Power Energy Cost	Schedule G-6.0, Page 4 of 4	$ 0.030795	$ 0.030795	$ 0.030795
Purchased Power Demand Cost	Schedule G-6.0, Page 4 of 4	$ 0.049412	$ 0.049412	$ 0.049412
Remainder: Distribution Wires Component in Residential Energy Charge	L1 - L2 - L3	$ 0.040954	$ 0.047393	$ 0.047393
Lost Fixed Cost Calculation:				
Total Residential DG Customers at TY End		1,262	1,262	1,262
Monthly kWh Produced by 6.51 kW AC PV System (Estimated)	Estimated	922	922	922
PV System kWh Compensated at Full Retail		922	922	397
Purch Power Demand Lost Fixed Cost - Monthly	L7 x L3	$ 45.57	$ 45.57	$ 19.59
Distr. Wires Lost Fixed Cost - Monthly	L7 x L4	$ 37.77	$ 43.71	$ 18.79
Total Lost Fixed Costs - Monthly	L8 + L9	$ 83.34	$ 89.28	$ 38.38
Total Lost Fixed Costs Annual	L10 x L5 x 12	$ 1,262,079	$ 1,352,006	$ 581,285

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF MAXIMUM ALLOWABLE LINE EXTENSION INVESTMENT - PROPOSED RATE
RESIDENTIAL

		Class Average Usage
1	**Billing Units**	
1.1	Consumers (12 month sum)	12
1.2	Allocated Annual kW [(L1.4/(1-L1.6)]/L1.5)	23.56
1.3	Monthly kWh	844
1.4	Annual kWh	10,128
1.5	Allocated kWh per kW Purchased	452.88
1.6	Losses	5.066447%
2	**Wires Rate**	
2.1	Customer Charge	20.00
2.2	Energy Charge (Average cost)	0.040600
3	**Total Annual Billing**	651.20
3.1	Less: Consumer Accounting, Meter Reading, Etc.	(67.39)
3.2	Total Annual Wires w/o Consumer Accounting	583.81
4	**Return Factor Excluding Depreciation (as % of Plant Investment)**	
4.1	Excluding Consumer Accounting, Etc.	11.00%
5	**Depreciation Factor for Project Life**	
5.1	5 Year Project Life	20.00%
5.2	10 Year Project Life	10.00%
5.3	20 Year Project Life	5.00%
5.4	30 Year Project Life	3.33%
5.5	35 Year Project Life	2.86%
6	**Supported Investment Including System Capacity Requirements [L3.2/(L4.1+L5.X)]**	
6.1	5 Year Project Life	1,883.14
6.2	10 Year Project Life	2,779.79
6.3	20 Year Project Life	3,648.37
6.4	30 Year Project Life	4,072.54
6.5	35 Year Project Life	4,212.47
7	**Allocated System Investment for Capacity Requirements**	
7.1	Demand Component of Plant per Allocated kW	58.57
7.2	Allocated kW	23.56
7.3	Allocated System Investment (L7.1 x L7.2)	1,379.77
8	**Cooperative's Allowable Direct Investment (L6.X - L7.3)**	
8.1	5 Year Project Life	503.37
8.2	10 Year Project Life	1,400.02
8.3	20 Year Project Life	2,268.60
8.4	30 Year Project Life	2,692.77
8.5	35 Year Project Life	2,832.70

TRICO ELECTRIC COOPERATIVE, INC.

CALCULATION OF FIXED RETURN FACTOR

	Residential	GS 1	GS 2	GS 3
1 Plant In Service	172,916,694	7,073,808	4,970,837	21,260,555
2 Rate Base	127,592,570	5,210,623	3,724,630	16,096,483
Expenses:				
3 O&M, A&G, Cust. Acct	10,754,004	469,635	307,486	1,545,748
4 Taxes	2,740,801	112,123	78,790	336,989
5 Consumer Accounting, Meter Reading, Etc.	2,549,868	125,240	22,879	187,349
6 Average Consumers	37,838	1,488	251	419
7 Consumer Accounting, Meter Reading, Etc. Per Cons	67.39	84.17	91.15	447.13
8 as % of Plant	1.47%	1.77%	0.46%	0.88%
9 System Average Rate of Return on Rate Base	6.3320%	6.3320%	6.3320%	6.3320%
Expenses Excluding Depreciation as % of Plant:				
12 O&M, A&G, Cust. Acct (L3/L1)	6.22%	6.64%	6.19%	7.27%
13 Taxes (L4/L1)	1.59%	1.59%	1.59%	1.59%
14 Required Return as % of Plant in Service	4.67%	4.66%	4.74%	4.79%
15 Less: Consumer Accounting, Meter Reading, Etc.	-1.47%	-1.77%	-0.46%	-0.88%
16 Total Revenue Requirement as % of Plant	11.00%	11.12%	12.06%	12.77%
17 Total Allocated kW	883,687	22,382	43,563	274,001
18 kWh Purchased	400,207,470	11,199,542	11,364,030	119,626,295
19 Allocated kW per kWh Purchased	452.88	500.38	260.86	436.59
20 Line Losses	5.066447%	5.066447%	5.066447%	5.066447%
<u>Demand Component of Plant</u>				
21 Trans Demand	6,680,833	170,355	331,594	2,085,566
22 Distr. Sub Demand	11,498,701	293,206	570,772	3,589,567
23 Distr. Bkb Demand	33,579,639	856,250	1,666,680	10,482,608
24 Total	51,759,173	1,319,811	2,569,046	16,157,741
25 Demand Component of Plant Per Allocated kW	58.57	58.97	58.97	58.97
<u>Demand Component of Rate Base</u>				
26 Trans Demand	6,070,251	154,786	301,289	1,894,960
27 Distr. Sub Demand	8,596,945	219,214	426,698	2,683,722
28 Distr. Bkb Demand	24,747,440	631,037	1,228,306	7,725,447
29 Total	39,414,636	1,005,037	1,956,293	12,304,129
30 Demand Component of Rate Base Per Allocated kW	44.60	44.90	44.91	44.91

TRICO ELECTRIC COOPERATIVE, INC.

Direct Assignment Facilities Impact

Direct Assignment Facilities Purchase	$	7,824,026.09				
		SWTC		Trico		Difference
Depreciation Expense	$	202,607	$	215,943	$	13,336
Property Taxes	$	122,842	$	219,073	$	96,231
Insurance Expense	$	15,295	$	5,733	$	(9,562)
Interest Expense	$	455,210	$	234,721	$	(220,490)
Margin Component	$	303,474	$	260,540	$	(42,934)
Total Costs	$	1,099,428	$	936,010	$	(163,419)
Net Impact					$	(163,419)

An Act

ENROLLED SENATE
BILL NO. 1456

By: Griffin of the Senate

and

Turner, Echols, Jackson, Newell, Schwartz, Murphey, Brumbaugh, Pittman, Rousselot and Fisher of the House

An Act relating to public utilities; amending 17 O.S. 2011, Section 156, which relates to distributed generation costs; defining terms; modifying prohibition relating to recovery of certain fixed costs from electric customers utilizing certain distributed generation; prohibiting subsidization of certain costs among customer class; requiring rate tariff adjustment by certain date; and providing an effective date.

SUBJECT: Electrical power distribution requirements

BE IT ENACTED BY THE PEOPLE OF THE STATE OF OKLAHOMA:

SECTION 1. AMENDATORY 17 O.S. 2011, Section 156, is amended to read as follows:

Section 156. A. As used in this section:

1. "Distributed generation" means:

   a. a device that provides electric energy that is owned, operated, leased or otherwise utilized by the customer,

b. is interconnected to and operates in parallel with the retail electric supplier's grid and is in compliance with the standards established by the retail electric supplier,

c. is intended to offset only the energy that would have otherwise been provided by the retail electric supplier to the customer during the monthly billing period,

d. does not include generators used exclusively for emergency purposes,

e. does not include generators operated and controlled by a retail electric supplier, and

f. does not include customers who receive electric service which includes a demand-based charge.

2. "Fixed charge" means any fixed monthly charge, basic service, or other charge not based on the volume of energy consumed by the customer, which reflects the actual fixed costs of the retail electric supplier.

3. "Retail electric supplier" means an entity engaged in the furnishing of retail electric service within the State of Oklahoma and is rate regulated by the Oklahoma Corporation Commission.

B. No ~~public utility~~ retail electric supplier shall increase rates charged or enforce a surcharge ~~on the basis of the use or installation of a solar energy device by a consumer~~ above that required to recover the full costs necessary to serve customers who install distributed generation on the customer side of the meter after the effective date of this act.

C. No retail electric supplier shall allow customers with distributed generation installed after the effective date of this act to be subsidized by customers in the same class of service who do not have distributed generation.

D. A higher fixed charge for customers within the same class of service that have distributed generation installed after the effective date of this act, as compared to the fixed charges of those customers who do not have distributed generation, is a means to avoid subsidization between customers within that class of service and shall be deemed in the public interest.

E. Retail electric suppliers shall implement tariffs in compliance with this act no later than December 31, 2015.

SECTION 2. This act shall become effective November 1, 2014.

Passed the Senate the 12th day of March, 2014.

Presiding Officer of the Senate

Passed the House of Representatives the 14th day of April, 2014.

Presiding Officer of the House
of Representatives

OFFICE OF THE GOVERNOR

Received by the Office of the Governor this 15th day of April, 2014, at 3:46 o'clock P M.

By: Audrey Rockwell

Approved by the Governor of the State of Oklahoma this 21st day of April, 2014, at 3:43 o'clock P M.

Governor of the State of Oklahoma

OFFICE OF THE SECRETARY OF STATE

Received by the Office of the Secretary of State this 21st day of April, 2014, at 5:40 o'clock P. M.

By: Chris Benge

EXHIBIT DWH - 12

Stricken language would be deleted from and underlined language would be added to present law.
Act 827 of the Regular Session

State of Arkansas *As Engrossed: H2/26/15 H3/17/15*
90th General Assembly
A Bill
Regular Session, 2015 HOUSE BILL 1004

By: Representative S. Meeks

For An Act To Be Entitled

AN ACT TO REQUIRE ELECTRIC UTILITIES TO COMPENSATE NET-METERING CUSTOMERS FOR NET EXCESS GENERATION CREDITS IN CERTAIN CIRCUMSTANCES; AND FOR OTHER PURPOSES.

Subtitle

TO REQUIRE ELECTRIC UTILITIES TO COMPENSATE NET-METERING CUSTOMERS FOR NET EXCESS GENERATION CREDITS IN CERTAIN CIRCUMSTANCES.

BE IT ENACTED BY THE GENERAL ASSEMBLY OF THE STATE OF ARKANSAS:

SECTION 1. Arkansas Code § 23-18-603(6), concerning a definition used under the Arkansas Renewable Energy Development Act of 2001, is amended to read as follows:

(6) "Net-metering facility" means a facility for the production of electrical energy that:

(A) Uses solar, wind, hydroelectric, geothermal, or biomass resources to generate electricity, including, but not limited to, fuel cells and micro turbines that generate electricity if the fuel source is entirely derived from renewable resources;

(B) Has a generating capacity of not more than<u>:</u>

<u>(i) The greater of</u> twenty-five kilowatts (25 kW) <u>or one hundred percent (100%) of the net-metering customer's highest monthly usage in the previous twelve (12) months</u> for residential use<u>;</u> or ~~three~~

<u>(ii) Three</u> hundred kilowatts (300 kW) for any other

use unless otherwise allowed by a commission under § 23-18-604(b)(5);

(C) Is located in Arkansas;

(D) Can operate in parallel with an electric utility's existing transmission and distribution facilities; and

(E) Is intended primarily to offset part or all of the net-metering customer requirements for electricity; and

SECTION 2. The introductory language of Arkansas Code § 23-18-604(b), concerning the authority of the Arkansas Public Service Commission, is amended to read as follows:

(b) Following notice and opportunity for public comment, ~~the Arkansas Public Service Commission~~ a commission:

SECTION 3. Arkansas Code § 23-18-604(b)(1), concerning the authority of the Arkansas Public Service Commission, is amended to read as follows:

(1) Shall establish appropriate rates, terms, and conditions for net-metering contracts, including ~~a~~:

(A)(i) A requirement that the rates charged to each net-metering customer recover the electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers.

(ii) The electric utility's entire cost of providing service to each net-metering customer within each of the electric utility's class of customers under subdivision (b)(1)(A)(i) of this section:

(a) Includes without limitation any quantifiable additional cost associated with the net-metering customer's use of the electric utility's capacity, distribution system, or transmission system and any effect on the electric utility's reliability; and

(b) Is net of any quantifiable benefits associated with the interconnection with and providing service to the net-metering customer, including without limitation benefits to the electric utility's capacity, reliability, distribution system, or transmission system; and

(B) A requirement that net-metering equipment be installed to accurately measure the electricity:

~~(A)~~ (i) Supplied by the electric utility to each *net-metering customer; and*

~~(B)~~ (ii) Generated by each net-metering customer that is fed back to the electric utility over the applicable billing period;

SECTION 4. Arkansas Code § 23-18-604(b)(5) and (6), concerning the authority of the Arkansas Public Service Commission, are amended to read as follows:

(5) May increase the ~~peak~~ generating capacity limits for individual net-metering facilities if doing so results in distribution system, environmental, or public policy benefits; ~~and~~

(6) Shall provide that:

(A)(i) The net excess generation credit remaining in a net-metering customer's account at the close of ~~an annual~~ a billing cycle~~, up to an amount equal to four (4) months' average usage during the annual billing cycle that is closing, shall be credited to the net-metering customer's account for use during the next annual billing cycle;~~ shall not expire and shall be carried forward to subsequent billing cycles indefinitely.

(ii) However, for net excess generation credits older than twenty-four (24) months, a net-metering customer may elect to have the electric utility purchase the net excess generation credits in the net-metering customer's account at the electric utility's estimated annual average avoided cost rate for wholesale energy if the sum to be paid to the net-metering customer is at least one hundred dollars ($100).

(iii) An electric utility shall purchase at the electric utility's estimated annual average avoided cost rate for wholesale energy any net excess generation credit remaining in a net-metering customer's account when the net-metering customer:

(a) Ceases to be a customer of the electric utility;

(b) Ceases to operate the net-metering facility; or

(c) Transfers the net-metering facility to another person; and

~~(B) Except as provided in subdivision (b)(6)(A) of this~~

~~section, any net excess generation credit remaining in a net-metering customer's account at the close of an annual billing cycle shall expire; and~~

~~(C) Any~~ (B) A renewable energy credit created as the result of electricity supplied by a net-metering customer is the property of the net-metering customer that generated the renewable energy credit~~.~~; and

SECTION 5. Arkansas Code § 23-18-604(b), concerning the authority of the Arkansas Public Service Commission, is amended to add an additional subdivision to read as follows:

(7) May allow a net-metering facility with a generating capacity that exceeds three hundred kilowatts (300 kW) if:

(A) The net-metering facility is not for residential use; and

(B) Allowing an increased generating capacity for the net-metering facility would increase the state's ability to attract businesses to Arkansas.

SECTION 6. Arkansas Code § 23-18-604, concerning the authority of the Arkansas Public Service Commission, is amended to add additional subsections to read as follows:

(c)(1) As used in this section, "avoided costs":

(A) For the Arkansas Public Service Commission, means the same as defined in § 23-3-702; and

(B) For a municipal utility, is defined by the governing body of the municipal utility.

(2) Avoided costs shall be determined under § 23-3-704.

(d)(1) Except as provided in subdivision (d)(2) of this section, an electric utility shall separately meter, bill, and credit each net-metering facility even if one (1) or more net-metering facilities are under common ownership.

(2)(A) At the net-metering customer's discretion, an electric utility may apply net-metering credits from a net-metering facility to the bill for another meter location if the net-metering facility and the separate *meter location are under common ownership within a single electric utility's service area.*

(B) Net excess generation shall be credited first to the

net-metering customer's meter to which the net-metering facility is physically attached.

(C) After applying net excess generation under subdivision (d)(2)(B) of this section and upon request of the net-metering customer under subdivision (d)(2)(A) of this section, any remaining net excess generation shall be credited to one (1) or more of the net-metering customer's meters in the rank order provided by the net-metering customer.

/s/S. Meeks

APPROVED: 03/31/2015

Valuation of Distributed Solar: A Qualitative View

A critical evaluation of the arguments used by solar DG advocates shows that those arguments may often overvalue solar DG. It is time to reassess the value of solar DG from production to dispatch and to calibrate our pricing policies to make certain that our efforts are equitable and carrying us in the right direction.

Ashley Brown and Jillian Bunyan

Ashley Brown *is Executive Director of the Harvard Electricity Policy Group and Of Counsel in the Boston office of the law firm Greenberg Traurig LLP. Mr. Brown is a former Commissioner of the Public Utilities Commission of Ohio and former Chair of the National Association of Regulatory Commissioners Electricity Committee.*

Jillian Bunyan *is an associate in the Philadelphia office of Greenberg Traurig LLP. Prior to joining the firm, Ms. Bunyan was an attorney in the United States Environmental Protection Agency's Office of Regional Counsel in Seattle, Washington.*

I. Assessing the Value of Distributed Solar Generation – An Overview

The purpose of this article is to assess the value of residential distributed generation (DG) solar photovoltaics (PV) and appropriate pricing for its value and output. In particular, the article will address the question of whether retail net metering, the way that it is presently applied in most states, is an equitable way to compensate customers who own or lease solar DG. The article will also critically examine the argument for the "value of solar" approach to compensating residential solar DG customers. The article will conclude that retail net metering and "value of solar" are severely flawed schemes for pricing solar DG.

Retail net metering overvalues both the energy and capacity of solar DG, imposes cross-subsidies on non-solar residential customers, and is socially regressive because it effectively transfers wealth from less affluent to more affluent consumers. The "value of solar" approach being advanced by

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some solar DG advocates subjectively, and often artificially, inflates the value of solar DG and discounts the costs. This article also concludes that proposals for market-based energy prices, as well as demand and fixed charges as applied to solar DG hosts, are reasonable ways to rectify the cross-subsidies in net metering. It suggests that market-based prices for solar DG provide the best incentives for making solar more efficient and economically viable for the long term.

Solar PV has some very real benefits and long-term potential. The marginal costs of producing this energy are zero. If one looks at environmental externalities, then the carbon emissions from the actual process of producing this energy itself, without taking the secondary effects into consideration, are also zero. Significantly, the costs of producing and installing solar PV have declined in recent years, adding to the potential long-term attractiveness of solar. Those are very real benefits that would be valuable to capture. In its current, most common configuration, however, solar DG has some drawbacks that inhibit it from capturing its full value.

Solar PV is intermittent and thus requires backup from other generators and cannot be relied on to be available when called upon to produce energy. Thus, its energy value is entirely dependent on when it is produced and its capacity value is, at best, marginal. To fully develop the resource, therefore, it is imperative to provide pricing that will incent the fulfillment of solar PV's potential, by linking itself to storage, more efficient ways of catching the sun's energy, or with other types of generation (e.g. wind) that complement its availability. Thus, it is critical that prices be set in such a fashion as to provide incentives for productivity and reliability and not to subsidize solar DG at a decidedly low degree of optimization. Currently, rates for most residential consumers are based on volume. That is, residential customers are simply billed based on the number of kilowatt-hours that they consume based on average costs to serve all residential consumers. Solar has huge potential, but to attain it, solar DG needs to receive the price signals to actually fulfill its potential.

In its current, most common configuration, solar DG has some drawbacks that inhibit it from capturing its full value.

Not only does net metering deprive solar PV of the price signals necessary to capture its full value, it also leads the changes in retail pricing that undermine the promotion of energy efficiency. As solar DG becomes more widely deployed, utilities and their regulators will likely become increasingly concerned with diminution of revenues required to support the distribution system that is caused by the use of net metering. That concern will inevitably lead utilities and regulators to recover more of their costs through the fixed, rather than the variable, components of their rates. Thus, the price signal to be more efficient will be substantially diluted.

Many in the solar industry have come to recognize that retail net metering (NEM) is, in this age of smart grid and smart pricing, no longer a defensible method for pricing solar DG. Having recognized the inevitable demise of a pricing system that favors solar DG through cross-subsidization by other customers, many solar DG advocates have shifted to an argument that pricing should be based on consideration of the "value of solar." While the authors do not subscribe to that point of view, as the argument is being included in the national conversation, it seems appropriate to address it.

II. Solar DG and Retail Net Metering – Definition of Terms

Powering your home with clean energy generated from the

 1040-6190/, http://dx.doi.org/10.1016/j.tej.2014.11.005

solar panels on your roof, and selling the excess energy to the utility, are appealing prospects to a public increasingly attuned to environmental, energy efficiency, and self-sufficiency considerations. It is not hard to see why solar DG has substantial public appeal.

To begin, it is necessary to note that the terms "net metering," "retail net metering," and "net energy metering" will be used interchangeably and synonymously throughout the article. Net metering refers to when electricity meters run forward when solar DG customers are purchasing energy from the grid. When those customers produce energy and consume it on their premises, the meter slows down and then simply stops, and when the customer produces more energy than is consumed on the premises, the meter runs backwards. Thus, the solar DG customer pays full retail value for all energy taken off the grid, pays nothing for energy or distribution when self-consuming energy produced on the premises, and is paid the fully delivered retail price for all energy exported into the system. At the end of whatever period is specified, the meter is read and the customer either pays the net balance due, or the utility pays the customer for excess energy delivered. The reconciliation is made without regard to when energy is produced or consumed. This is how transactions between owners of residential DG and utilities have traditionally been handled.

There are other forms of net metering such as wholesale net metering, where exports into the system are compensated at the wholesale price, often the local marginal price (LMP). There are other variations as well, but for purposes of the article, when the terms NEM or net metering are used, they refer to the retail variety.

There are, conceptually, four possible approaches to pricing energy produced by solar DG.

There are, conceptually, four possible approaches to pricing energy produced by solar DG. One market-based approach is to set the price to reflect the market clearing price in the wholesale market at the time the energy is produced. A second approach would be a cost-based approach, where the price is set based on a review of the costs or according to standard costing methodology. A third approach, already defined above, would be net metering. Finally, a fourth approach would be to administratively derive a "value of solar" based on analysis of avoided costs and whatever else the evaluators believe to be worthy of measure.

As you will see, while the authors do not believe this fourth approach to be appropriate, analysis of the criteria its advocates believe are important should be conducted and evaluated – not to set the price, but simply to establish the context for evaluating the reasonableness of the pricing methodology approved.

III. 'Value of Solar' vs. Wholistic Analysis

Optimally, prices for electricity are determined by a competitive market or, absent competitive conditions, should be derived from cost-based regulation. In both cases the prices are subjected to an external discipline that should result in efficient resource decisions devoid of arbitrary or "official" biases. Subjective consideration of the "value" of particular technologies and where they may rank in the merit order of "social desirability," effectively removes the discipline that is more likely to produce efficient results. Moreover, even where non-economic externalities are thrown into the valuation mix, the pricing of an energy resource must still be disciplined by examination of the economic merit order in attaining the externality objective. Whereas both the marketplace and transparent cost-based regulation are likely to produce coherent pricing that

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allows us to enjoy a degree of comfort knowing that efficient performance will likely lead to productivity, subjective consideration of soft criteria, like "value of solar," are a step away from economic coherence and efficiency.

Economics are critical and efficiency is of vital importance. There are also other economic values, besides efficiency, including those that go beyond short-term efficiency. Certainly, many people believe that other, non-economic factors need to be considered. Similarly, the fairness of the impact on customers also needs to be factored into any decision. There has, for many years, been a running debate in electricity regulation as to whether externalities ought to be factored into regulatory decisions. This article does not intend to join that debate, nor express any point of view as to what is permissible or impermissible under applicable law. Rather, this article suggests that if externalities are to be considered, then all relevant ones deserve attention, as opposed to "cherry picking" the issues to best protect a particular interest. Further, if non-economic objectives are to be factored into ratemaking, then it is wise to carefully consider the most economically efficient ways of attaining those objectives.

There are a number of criteria that are important to the full valuation of solar PV. One should begin by looking at the cost of producing energy. Beyond that, the criteria would include availability/capacity, reliability, energy value, impact on system operations and dispatch, transmission costs and effects, distribution costs and effects, and hedge value. Solar DG proponents often phrase these issues in terms of avoided costs. In addition to those dimensions, there are also the following: degree of subsidization and cross-subsidization, efficiency considerations, impact on alternative technologies, market price impact, reliability, and social effects including the environmental, customer, and social class impacts. There is also the issue of whether solar DG enhances the level of competition in the industry.

Certainly, many people believe that other, non-economic factors need to be considered.

IV. Net Energy Metering – Why Are We Paying More for Less?

Retail net energy metering, as practiced, does not capture all of the value enumerated above. NEM significantly overvalues distributed solar generation. More specifically, it does the following:

1. Creates a cross-subsidy from non-solar to solar customers;
2. Fails to reflect the inefficiency of small-scale solar PV relative to other forms of generation, including alternative renewable resources;
3. Constitutes price discrimination in favor of an inefficient resource;
4. Significantly overvalues both the capacity and reliability value of solar DG;
5. Adversely impacts the degree of competitiveness in the industry;
6. Artificially inflates the transmission value of solar DG;
7. Fails to account for the fact that the value of energy varies widely depending on when it is actually produced;
8. Distorts price signals for energy efficiency;
9. Causes socially regressive economic impact;
10. Assumes system benefits from solar DG that, in fact, may not exist;
11. Overvalues its contribution to carbon reduction;
12. Vastly inflates its value as a fuel hedge; and
13. Undervalues and underfunds the distribution system.

Despite failing to capture these values, NEM has become the prevalent form of tariff for residential solar DG in

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the United States. This is because NEM was never developed as part of a fully and deliberatively reasoned pricing policy. NEM was simply never a conscious policy decision. It is basically a default product of two (no longer relevant) considerations, one practical and the other technological. The practical reason is that residential distributed generation had such an insignificant presence in the market that its economic impact was marginal at best. Thus, no one was seriously concerned about "getting the prices right." The second, technological reason is that until recently the meters most commonly deployed, especially at residential premises, have had very little capability other than to run forward, backward, and stop. Thus, for technical reasons, NEM was simple to implement and administer and, as a practical matter given the paucity of DG, there was no compelling reason to go to the trouble of remedying a clearly defective pricing regime. Many states have recognized the problems with NEM but, seeing no alternatives, put in place production caps to limit any harm caused by a clearly deficient pricing regime.

V. Residential Retail Net Metering Sets Up Unfair and Counterproductive Cross-Subsidies

Beyond failing to capture the values above, there are other problems with NEM. Under NEM, when DG providers export energy to the system, consumers are required to pay them full retail rates for a wholesale product. What everyone agrees upon is that solar DG provides an energy value, but there is considerable disagreement about what that value is. Solar proponents argue that solar DG has a capacity value as well. That value, if it exists at all, is minimal. While there may well be reasons to treat DG differently with respect to wholesale transmission there is, absent a solar host leaving the grid, absolutely no reason to discriminate between wholesale and DG products with regard to the fixed costs of the distribution system and its operations.

If the costs of the distribution system were variable with energy production, that exemption would be sensible, but they are not.

Under NEM, however, solar DG providers are compensated at full retail prices for what they provide. That includes the not-insignificant cost of services that they do not provide, including distribution costs, administrative, and back office operations. There can be no justification for forcing consumers to pay a provider for service that they not only do not provide but, in fact, have no capability to provide.

Solar DG producers remain connected to the grid and are fully reliant upon it during the many hours of the day when solar energy is not available. Under NEM, that solar DG producer is excused from paying his/her share of the costs of the distribution system when energy is being produced on the premises. If the costs of the distribution system were variable with energy production, that exemption would be sensible, but they are not. Distribution costs are fixed, and do not vary with energy production or consumption. Thus, excusing solar DG customers from paying for their own distribution costs when their solar units are producing energy has no justification in either policy or economics. Making matters worse, the costs solar DG providers do not pay under NEM are either reallocated to non-solar customers or have to be absorbed by the utility. Both outcomes are unacceptable and unjustifiable. There is no reason why solar DG customers should receive free backup service, compliments of either their neighbors or the utility.

Utilities are obliged to provide full requirements service to all of their customers, including, of course, their solar host

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customers. In regard to solar hosts, the utility is obliged, in case the on-premises generation does not cover their full demand, to fill the gap between the full demand and the amount of self-generation. Utilities are also obliged to purchase energy and/or capacity so that solar hosts may rely on the utility when solar units are not generating. Given that solar PV units are intermittent and unpredictable regarding when they will produce, providing that backup is an ongoing responsibility and cost to utilities. Compounding those costs is the fact, as stated elsewhere in the article, peak times of electricity use (i.e. when prices are highest) are trending later in the day, when solar PV does not produce. As such, utilities must provide electricity to solar hosts at times when demand is high and energy prices are high. It would violate a the fundamental principle of regulation that cost causers should pay for the costs they impose, not to recognize the actual costs of that backup service in the rates paid by solar hosts.

Another cross-subsidy relates to the intermittent nature of solar energy. No utility with an obligation to serve can be fully reliant on the availability of solar when it is needed. Indeed, no solar host who values reliability can afford to be dependent on his/her own solar DG unit. While this point will be discussed further *infra* suffice it to say that this gives rise to two types of demand charge related cross-subsidy. The first arises when the distributor relies on the availability of solar for making day-ahead purchases and the other arises when it does not do so. When it does rely on the availability of solar and it turns out that solar energy is not available when called upon, the

utility is compelled to purchase replacement energy in the spot market at the marginal cost, which is almost certainly higher than the price of the solar energy on whose availability it had relied. In notable contrast to what happens in the wholesale market when a supplier who is relied upon fails to deliver, those incremental costs have to be borne by the utility, which passes them on to all customers, as opposed to being borne by the specific solar DG customer whose failure to deliver caused the costs to be incurred.

If the distributor, in recognition of solar's intermittency, instead chooses to hedge against the risk of solar's unavailability, the cost of the hedge is likewise passed on to all customers rather than simply those whose supply unpredictability caused the cost to be incurred. Both of these forms of cross-subsidy violate a bedrock principle of regulation – costs should be allocated to the cost causer. The function of that principle, of course, is to provide price signals to improve performance, but NEM fails to provide such signals and essentially holds solar DG providers harmless for their own very low capacity factors and inefficient performance.

NEM cross-subsidies, in large part, provide short-term benefits to the solar DG industry, but are highly detrimental to the value of solar in the long term. In the short term they constitute a wealth transfer from non-solar customers to the solar industry. In the long term, however, they are actually harmful to solar energy because NEM provides absolutely no incentive to improve the performance of a generating resource that, among renewables, already ranks last in efficiency and in cost effectiveness for reducing carbon emissions. In effect, the solar DG industry is putting its short-term profits ahead of the long-term value of solar energy. If solar DG advocates prevail in seeking to maintain NEM, that victory will be short-lived, because markets, both regulated and unregulated, do not prop up inefficient resources over the long term.

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NEM is also woefully ineffective at providing the appropriate price signals. Electricity prices can be quite volatile over the course of every day and vary seasonally as well. Rather than reflecting those prices, NEM simply treats all energy the same regardless of the time during which it is produced. For example, NEM fails to differentiate between energy produced on-peak and off-peak. In one scenario, it prices off-peak solar DG at a level that is averaged with on-peak prices, thus effectively over-valuing the energy. Conversely, if solar DG were actually produced on-peak, NEM would average that price with off-peak prices, thus undervaluing the energy. Any form of dynamic pricing, ranging from time of use to real-time, could address this issue with more precision than flat, averaged prices. Interestingly, under the first scenario, cross-subsidies would be paid to solar producers, while in the second scenario, solar producers would be cross-subsidizing the other ratepayers. In short, the price signal, and the efficiency that would flow from that, is rendered incoherent.

Some may argue that cross-subsidies are necessary to promote the growth of renewable energy, and certainly that can be debated. However, modernizing NEM to provide appropriate price signals would not remove the tax credits and other government-sanctioned or -sponsored subsidies. The fact that conscious subsidies and/or cross-subsidies are designed to promote a particular technology raises two key issues. First, many would argue that the government, including regulators, should not be picking winners and losers in the marketplace. While there may be merit to that view, it must also be recognized that, there may be

circumstances where, for policy reasons, government might want to provide support for a socially and economically desirable technology and/or assist it with research funding and to get it over the commercialization hump. That leads inexorably to the second and more relevant issue concerning solar DG: namely, that subsidies and cross-subsidies need to be designed as near-term boosts rather than a permanent crutch, and should be transparent. In other words, subsidies/cross-subsidies should be designed to serve as both a stimulus for the designated technology and an incentive to the producers and vendors of the technology to become more efficient. It might also be noted that subsidies from the Treasury are more appropriate for achieving broad social benefits that are cross-subsidies derived from a subset of the full society deriving the benefit.

In the case of solar DG, the objective of a subsidy/cross-subsidy would be to attain grid parity, assuming reasonably efficient operations, with other resources. The objective is to assist a technology to achieve commercial viability. The problem with NEM, of course, is that it is effectively an arbitrary financial boost of potentially endless duration, with absolutely no built-in incentive to increase efficiency and/or to achieve grid parity. In effect it requires non-solar customers to pay more for the least efficient renewable resource in common use and provide the solar industry with no economic incentive to improve its productivity or availability or wean itself off dependence on the cross-subsidy. It also has the effect of putting more efficient resources, particularly other renewables, at a competitive disadvantage. In short, NEM effectively substitutes political judgment for economic efficiency to determining marketplace success.

The reason why solar DG vendors and providers cling to cross-subsidies is because they find more comfort in receiving substantial cross-subsidies than

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EXHIBIT DWH -13

Rooftop Solar Remains the Most Expensive Form of Electricity Generation

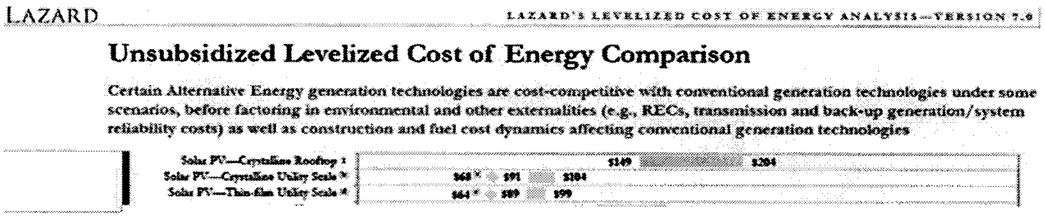

Figure 1: Rooftop Solar Remains the Most Expensive Form of Electricity Generation

they do in the prospect of becoming competitive. Solar DG is the most expensive form of renewable generation that is widely used today **(Figure 1)**.

The technological and practical reasons for permitting such incoherent pricing are no longer present in the marketplace. We now have pricing methods that are capable of measuring DG production as well as consumption on a more dynamic basis. In addition, solar DG market penetration has dramatically increased to the point that it can no longer be dismissed as marginal, so appropriate pricing is now a non-trivial issue. In addition, we now have very precise, location-specific energy and transmission price signals that provide a very transparent market price by which one can measure the economic value of distributed generation. These new developments, plus the fact that NEM was put in place on a default basis, mean that it is now time for a full-blown policy consideration of the most appropriate pricing policy for distributed generation.

For all of the reasons noted, NEM pricing results in large cross-subsidies, offers no incentives for efficiency – indeed, may even provide disincentives to invest in efficiency improvements – and results in consumers paying energy prices for solar DG that are far in excess of its market value and not even subject to cost-based oversight. Moreover, its *raison d'être* – inability to more accurately price solar DG facilities and low market penetration by solar energy – no longer exists. Solar energy is penetrating the market in greater numbers and is likely to continue to do so. Secondly, more sophisticated pricing enables us to measure solar energy and customer behavior on a much more efficient, dynamic basis. The fundamental reality is that NEM completely fails to capture the value of the product being priced.

VI. Placing a Value of Solar DG – Pricing and Economic Efficiency

Needless to say, pricing is of critical importance. It is important to address pricing in the context of tangible, enumerated values. Such an analysis is in contrast to certain efforts by solar DG advocates to attach a subjective value to solar and then derive prices from that value. It is preferable to derive prices from the values established by either costs or market, not ephemeral and subjective considerations.

It is worth re-emphasizing just how imperfect NEM actually is. The price of electric energy is not constant. Wholesale markets reflect that reality. Net metering and many forms of incentives do not reflect the values established by the market. Rather, a net metering regime relieves the solar panel host of any obligation to pay for the costs of the distribution system when energy is being produced, even though he/she

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Table 1: Rooftop Solar Subsidies Heavily Utilize Funding from Non-Solar Customers

DTE Energy

Consumers Energy
Count on Us

SolarCurrents and Net Metering funding mechanism for residential customers

	SolarCurrents (Phase 1)	SolarCurrents (Phase 2)	Funding Mechanism
Up-front solar subsidy	$2.40/W	$0.20/W	Renewable Surcharge
On-going solar subsidy	$0.11/kWh	$0.03/kWh	Renewable Surcharge
Net metering subsidy (unrecovered fixed cost)	$0.09/kWh	$0.09/kWh	*Unrecovered fixed costs are funded by non-solar customers
Total SolarCurrents and Net metering subsidy	**$0.20/kWh**	**0.12/kWh**	

remains reliant on it and, when the meter runs backwards, is effectively paid the full retail price for energy exported from the customer's premises. As a point of illustration, see **Table 1** for a funding mechanism for residential customers presented by DTE Energy to the Michigan Public Service Commission. According to DTE, the 9 cent per kilowatt-hour (kWh) net metering credit represents a differential that non-participating customers must pay.

Under NEM, compensation at retail rates is not cost-reflective because net metering means that solar DG energy exported into the distribution network is compensated at the full bundled retail rate rather than at a price based on the unbundled cost of producing the energy. In almost all jurisdictions, that retail rate is flat and constant. Thus, it does not reflect the obvious fact that the energy has greater value at peak demand than it does off-peak. It is a deeply flawed value proposition. The fact is that the wholesale market produces hour-by-hour prices that provide generators, renewable and non-renewable alike, and consumers with important price signals that reflect real-time values. Both generators and demand responders are compensated according to those real-time prices. Solar DG-produced energy, by contrast, is compensated on a basis that lacks a foundation in either market or cost. The compensation is out of market because it is a flat price regardless of when it is produced or, for that matter, fails to reflect that many hours of the day that solar panels produce absolutely nothing. It is hard to avoid the conclusion that on an economic basis, the NEM-derived price paid for solar DG energy completely misses the value of solar during most hours of the day. Interestingly, part of the cause for this incorrect valuation is that rooftop solar units have generally been installed facing south, as opposed to west. Because demand peaks have been trending later in the day (as illustrated in the California and New England figures below), this southern exposure has proven to render peak production for solar even less coincident with demand. Had the appropriate market prices been in effect, it is highly unlikely that such a costly error would have occurred.

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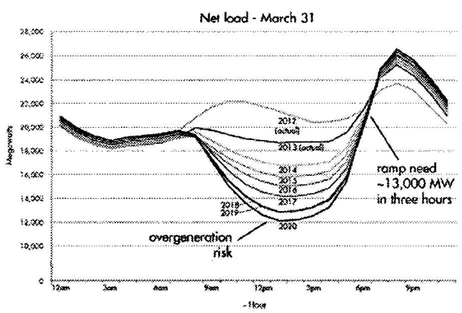
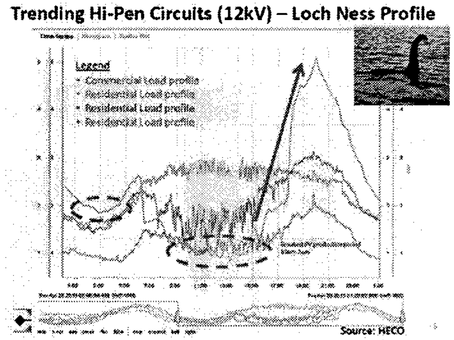
The Duck Curve - California



http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

The Nessie Curve - Hawaii

Trending Hi-Pen Circuits (12kV) – Loch Ness Profile



www.greentechmedia.com/articles/read/hawaiis-solar-grid-landscape-and-the-nessie-curve.

Figure 2: Ramping Needs Increased Due to Lack of Solar Prodution During Peak Demand

As is dramatically illustrated in the graph at left in **Figure 2**, enticed by a number of factors, not the least of which is net metering, substantial investment in the growth of solar capacity in the Golden State has enormously magnified the need for additional fossil plants, operating on a ramping basis, to compensate for the dropoff in solar production at peak. In that context, the absence of any meaningful signal to make solar more efficient (e.g. linking it with storage) is simply something that can no longer be tolerated. Not coincidentally, the charts from both the California and New England ISOs (found further *infra*), as well as that from DTE, illustrate the wisdom of compensating solar DG at LMP, so its price accurately reflects its value at the time of actual production and avoids requiring non-solar customers to pay prices for energy that far exceed its value.

A. Capacity value

The capacity value of a generating asset is derived from its availability to produce energy when called upon to do so. If a generator is not available when needed, it has little or no capacity value. By its very nature, solar DG on its own, without its own backup capacity (e.g. storage), can only produce energy intermittently. It is completely dependent on sunshine. Unless sunshine is guaranteed at all times solar DG is called upon to produce, it cannot be relied upon to always be available when needed. Moreover, even if all days were reliably sunny, the energy derived from the sun is only accessible at certain times of the day. In many jurisdictions, the presence and potency of sunshine is not coincident with peak demand. Frequently, for example, solar DG capacity is greatest in the early afternoon, while peak demand occurs later in the afternoon or in early evening. The two charts in **Figure 3** illustrate the lack of coincidence of solar production and peak demand in New England.[1]

These two charts dramatically demonstrate that, on the days chosen as representative of summer and winter in New England, solar PV is completely absent during the winter peak, reaches its peak production as peak demand is rising in the summertime, and drops off dramatically during almost the entire plateau period when demand is at peak. It should also be noted that on the days chosen, the sun was shining. The graph, of course, would look very different on cloudy days when solar production is virtually nil.

The Electric Power Research Institute (EPRI) graphs in **Figure 4** reveal similar patterns on a national level. The first graph

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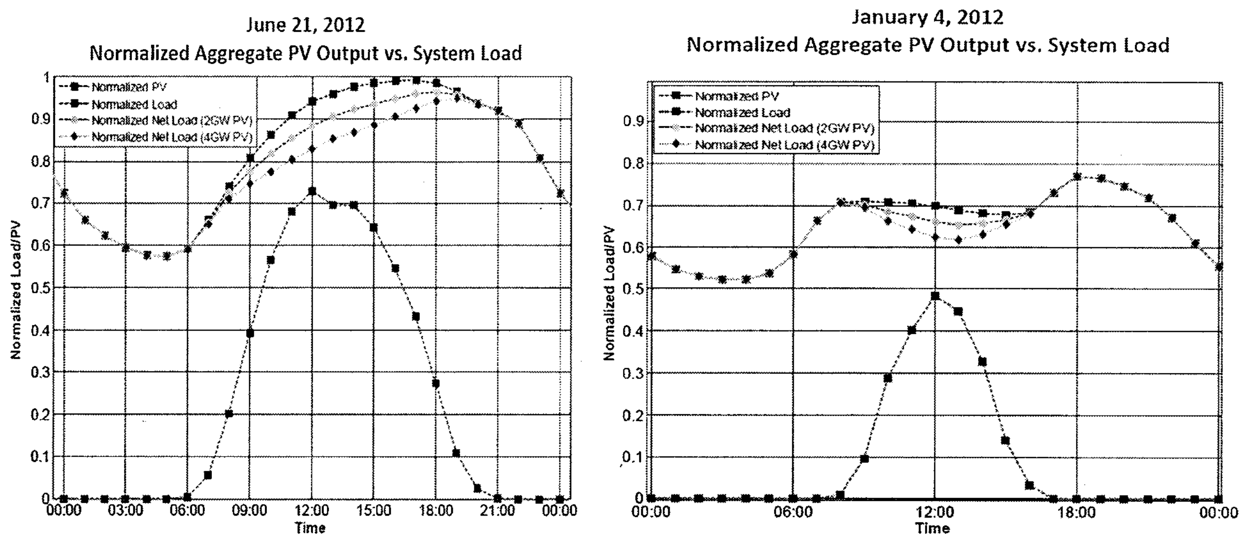

Figure 3: Lack of Coincidence of Solar Production and Peak Demand in New England

depicts the peak load reduction and ramp rate impacts resulting from high penetration of solar PV. The second illustrates the fact that because residential load and PV system output do not match, solar DG hosts use the grid for purchasing or selling energy most of the time.

As noted above, providers of capacity in the wholesale market may also have availability issues. In their case, however, if they are not available when called upon to produce, they are typically obligated to either provide replacement energy or to pay the

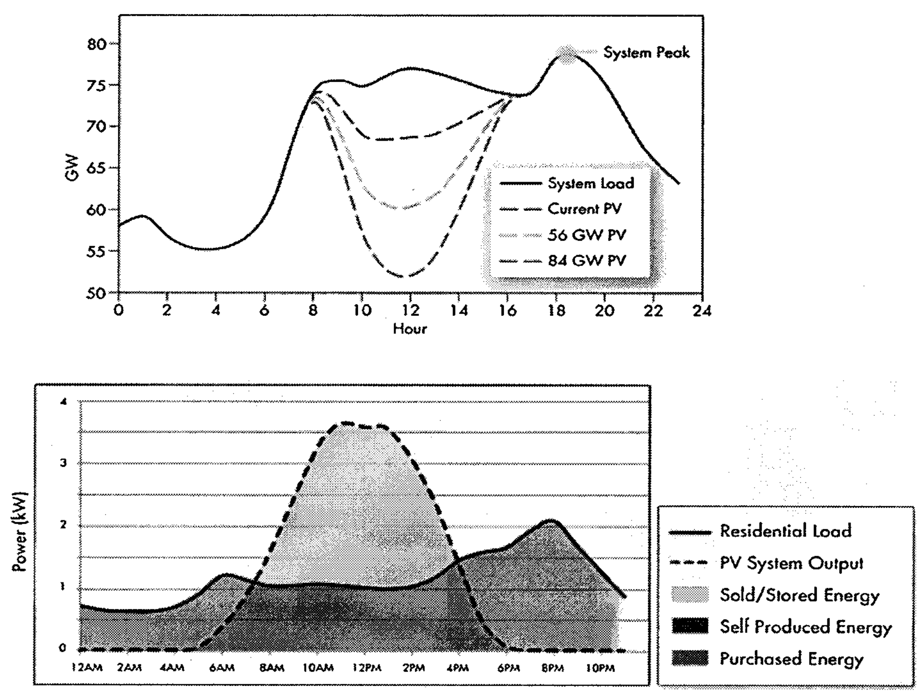

Figure 4: Increased Ramp Rates, Peak Load Reduction and Reliance on the Grid

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marginal cost of energy that they failed to deliver. Unless a similar obligation is imposed on solar DG providers, the capacity value of solar DG is reduced even further. Good pricing policy would suggest that DG prices should be fully reflective of the value of the type of capacity that is actually provided. As currently implemented, net metering does not adequately reflect how the capacity availability measures up to demand.

B. Availability and reliability

Many advocates of solar DG assert that it enhances overall reliability because the units are small, widely distributed but close to load, and not reliant on the high-voltage transmission system. It is argued that they are less impacted by disasters and weather disturbances. At best, these claims are highly speculative and, for the reasons noted below, quite dubious. It would be a mistake to attribute added value to solar DG because of reliability.

Solar DG is subject to disaster as much as any other installations. High winds, for example, can harm rooftop solar as much as any other facility connected or unconnected to the grid. Cloudy conditions can disrupt solar output while not affecting anything else on the grid.

Solar DG has more reliability benefit in some places than others. In Brazil, for instance, a system that largely relies on large hydropower plants with large storage reservoirs, solar has considerable long-term reliability value because whenever it generates energy it conserves water in the reservoirs, thereby adding to the reliability of the system. However, in a thermal-dominated system (like much of the United States), where there is little or no

storage, reliability has to be measured on more of a real-time basis. Therefore, solar's intermittency makes it unable to assure its availability when called upon to deliver energy. Indeed, it is far more likely that a thermal unit will have to provide reliability to back up a solar unit than the other way around.

It is also important to examine rooftop solar reliability issues in two contexts: that of the individual customer and that of the system as a whole. Solar DG vendors, as part of their sales pitch, claim that reliability is increased for a specific customer with a rooftop solar unit because on-site generation provides the possibility of maintaining electric power when the surrounding grid is down. When the sun is shining, this claim may be true. Conversely, without the sun, the claim has no validity. However, that argument only applies to the solar host.

On a technical point, a power inverter is an electronic device or circuitry that changes direct current to alternating current. During a system outage the power inverter is automatically switched off to prevent the backflow of live energy onto the system. That is a universal protocol to prevent line workers and the public from encountering live voltage they do not anticipate. Thus, if a solar DG unit is functioning properly, when the grid is down, the solar DG customer's inverter will also go down, making it impossible to export energy. If the solar DG unit is not functioning properly, then the unit may be exporting, but will do so at considerable risk to public safety and to workers trying to restore service. The result is that the solar panel provides virtually no reliability to anyone other than perhaps to the solar host.

Attributing reliability benefits to an intermittent resource is a stretch. By definition, intermittent resources are supplemental to baseload units. The only possible exceptions to that are, as noted above, where there are individual reliability benefits or where the availability of the unit is

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coincident with peak demand or has the effect of conserving otherwise depletable resources. Absent those circumstances, and absent storage, it is almost certainly the case that the system provides reliability for solar DG, rather than the other way around. That is particularly ironic given that in the context of net metering, solar DG hosts do not pay for that backup service while generating electric energy. In essence, in a net metering context, non-solar customers pay solar DG providers for reliability benefits that solar DG does not provide them, while solar DG customers do not pay for the reliability benefits they actually do receive.

From an investment perspective, solar DG pricing methods, like NEM, which redirect distribution revenues from distributors to solar PV providers who offer no distribution services are detrimental to reliability as they either deprive the sector of capital needed to maintain high levels of service or demand additional revenues from non-solar DG users who would ordinarily not have to pay such a disproportionate share of the costs. For utilities, the diversion of funds leaves them with a Hobson's choice of either delaying maintenance and/or needed investment, or seeking additional funds – in effect, a cross-subsidy from non-solar users. It is also relevant to reliability to again note that the prevalence of intermittent resources on the grid, including solar DG, may well cause new, cleaner, and more efficient generation to appear less attractive to investors. Over the long term, that effect could lead to reliability problems associated with inadequate generating capacity, especially at times of peak demand.

C. Solar DG does not avoid transmission costs

It is nearly impossible to demonstrate that solar DG will obviate the need for transmission, much less quantify the cost savings associated with this purported benefit. Of course, there is a simple way to calculate any actual transmission savings, and that is by compensating solar DG providers in the organized markets at the locational marginal cost of electricity at their location. That compensation model would have the benefit of capturing both the energy value and the demonstrable transmission value of solar DG. Absent that formulation, efforts to calculate actual transmission savings would be a difficult, perhaps entirely academic, task.

Solar DG advocates assert that real transmission savings are achieved through the deployment of DG, especially in systems that use locational marginal cost pricing. The argument is that by producing energy at the distribution level, less transmission service will be required, thereby reducing or deferring the need for new transmission facilities. It is also often contended that DG will reduce congestion costs, and perhaps even provide some ancillary services. All of that is theoretically possible but certainly not uniformly, or even inevitably, true.

Of course it is true that DG, absent any adverse, indirect effect it might have on the operations of the high-voltage grid, does not incur any transmission costs in bringing its energy to market. However, that is quite different than asserting that DG provides actual transmission savings. In fact, it would be incorrect to simply conclude across the board that solar DG will achieve transmission savings. It is possible that there could be transmission savings associated with solar DG deployment, but that can only be ascertained on a fact- and location-specific basis. Such savings would most likely be derived from reducing congestion or providing ancillary services of some kind. It is also theoretically

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possible, but highly unlikely, that massive deployment of solar DG will eliminate (or, more likely, defer) the need to build new transmission facilities. For a variety of reasons, including the complexities of transmission planning, the time horizons involved, the complex interactions of multiple parties, and economies of scale in building transmission, it is improbable that solar DG actually saves any investment in transmission capacity.

Indeed, a mere glance at the California ISO duck graph showing the need for ramping capacity to make up for the intermittent availability of solar DG provides a *prima facie* case for believing that the opposite is true and that solar DG may cause a need for more transmission to be built. These and other charts also show that as long as solar does not reduce peak energy use, transmission is likely needed to serve peak hours. Regardless, it is virtually impossible to demonstrate that, other the possibilities of reducing congestions costs (a value fully captured by LMP), there is very little likelihood of transmission saving being derived from solar DG.

D. Solar DG does not avoid distribution costs

It is more likely that solar DG will cause more distribution costs than it saves. That is because these generation sources could change voltage flows in ways that will require more controls, adjustments, and maintenance. Moving from a one-way to a two-way system will certainly increase the need for technical equipment to manage the reliability of the system. While DG solar may not be the only cause of this move the intermittent nature of solar makes

it particularly difficult to manage. It will also inevitably increase transaction costs for the utility to execute interconnection agreements and do the billing for an inherently more complicated transaction than simply supplying energy to a customer. It is impossible, unless a solar DG host leaves the grid, to envision a circumstance where solar DG would effectuate distribution savings.

Regarding distribution line losses, DG offers value only to DG providers when they consume what they produce because any DG output exported to the system is subject to the same line loss calculations that any other generator experiences. If there were locational prices on the distribution system, there might be line loss benefits that could be captured by DG but, since those price signals do not exist, the argument is purely academic.

VII. Lower Hedge Value

The theory advanced by some solar DG proponents is that because the marginal cost of solar is zero, it serves as a hedge against price volatility. In theory, that might make sense. In reality, however, solar is an intermittent resource that cannot serve as a meaningful hedge unless such zero-cost energy is both sufficiently and timely produced. Thus, solar DG is the equivalent of a risky counterparty whose financial position renders him incapable of assuring payment when required. Moreover, the value of a hedge depends on the amount of money the purchaser of the hedge is obliged to pay for the insurance and the amount and probability of the price he/she seeks to avoid paying. With a NEM system (or the high-priced "value of solar" approach that solar DG advocates seek), the price paid is highly likely to exceed the fuel or energy price most utilities would hedge against. In short, the argument ventures into the realm of the absurd. It amounts to: *Pay me a fixed price that is higher than the price you want to avoid, in order to avoid price volatility.*

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The argument that solar DG provides a valuable hedge function is reduced to virtual absurdity by the fact that the so-called hedge is not callable. In short, if the price rises to the level against which the hedge purchaser wants to be insured against, the solar provider of the hedge is not obliged to pay. That being the case, there is no hedge whatsoever.

VIII. Effects of Solar DG on Other Renewable Resources

A. Impact of a low capacity factor

Since 2008, as **Figure 5** from the United States Energy Information Administration (EIA) points out, solar PV has had the lowest capacity factor of any commonly used renewable energy resource in the U.S. It is also worth noting that while the overall costs of installing solar panels has declined (as noted above) the productivity of solar PV has remained constant at consistently low levels. It should be noted that the chart below compares only "utility-scale" projects. As noted in the Lazard study above, distributed solar is even less cost effective than utility-scale solar, which already occupies last place on the Department of Energy (DOE) ratings.

The stark reality of solar PV's combination of high prices and poor capacity factor carries over into the cost of reducing carbon emissions. An interesting dialog occurred recently between Charles Frank, an economist at the Brookings Institution, and Amory Lovins of the Rocky Mountain Institute.[2] Their dialogue, while contentious on many points, reflects similar views on the realities depicted in the EIA chart. Frank analyzed five non- or low-emitting generation resources by their cost effectiveness in reducing carbon and concluded that nuclear and natural gas, followed by hydro, wind, and solar were, in that order, the most cost-effective types of generators for reducing carbon. Lovins took issue with Frank for using outdated data and for not looking at energy efficiency. He also argued that nuclear ranked last in cost effectiveness, and expressed some reservations about the ranking of natural gas. However, what is significant is that, among renewable resources, Lovins concurred with Frank that solar DG is the least efficient renewable resource for reducing carbon. Thus, in the view of both men – who hold quite divergent views on how best to reduce carbon emissions – not only is solar DG expensive, it is the least cost-effective renewable resource for reducing carbon emissions.

B. Impact of higher-than-market price

Higher-than-market prices paid for solar DG has adverse effects on other renewable resources. All wholesale generators, renewable and otherwise, have to incorporate transmission and distribution costs into the price of energy delivered to customers. As mentioned above, it is true that transmission issues play out differently for distributed generation than for wholesale generation. Since DG, by definition, does not rely on transmission capacity, although DG might impact congestion costs in various ways, wholesale energy's delivered cost reflects transmission capacity

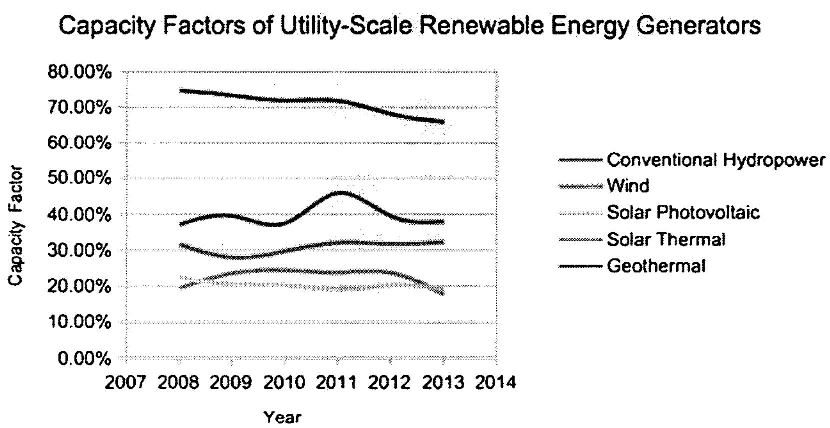

Figure 5: Capacity Factors of Utility-Scale Renewable Energy Generators

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costs while DG's does not. Thus, any competitive advantage for DG on that score is quite natural. However, under the net metering scheme, DG providers also do not have to incorporate distribution costs into their end product, and that results in a serious economic distortion of the generation markets in general as well as specifically in renewable markets. In fact, as noted *supra*, solar DG providers under NEM are actually paid for delivering their energy even though they provide no such service. Wholesale generators, unlike their DG counterparts, enjoy no such comparable enrichment for service they do not provide. The effect of NEM's highly inefficient and non-cost-reflective rates is to distort market prices in ways that reward inefficiency and will likely distort price signals that are essential for an efficient marketplace.

In addition, at a critical mass, artificially elevated solar DG prices are highly likely to create distortions and inefficiencies in the capacity and energy prices found within organized markets. An environment with two parallel pricing regimes, one market- or cost-based, and the other an arbitrary one neither market- nor cost-based, is simply economically incoherent and unsustainable. The overall effect of net metering is to increase the prices consumers pay for energy overall, without any assurance of any long-term benefit. Solar DG is artificially elevated to a preferential position above more-efficient, larger-scale generation, including all other renewables. The disparity in treatment between solar DG and other forms of energy suggests that net metering is not only federal preemption bait (as further discussed below); it is fundamentally anti-competitive as well. Indeed, it compels consumers to both cross-subsidize less efficient producers and to pay higher prices

than necessary for energy. It will also entice investors to allocate their capital to toward more profitable but less efficient generation. In terms of efficiency and public benefit, the incentives inherent in NEM are simply perverse.

Large-scale bulk power renewables (e.g. large-scale wind and solar farms, geothermal) are put at a particular disadvantage by NEM pricing of solar DG independent of costs or market for two basic reasons. First, large-scale renewables are more efficient and more cost-effective than DG, yet net metering provides a subsidy only to the less efficient form of generation. In fact, solar DG providers are compensated for the energy they export at a price that can range from two to six times the market price for energy. Second, in those states with renewable portfolio standards (RPS), the entry of a critical mass of non-cost-justified solar DG units into the market could have the effect of driving more efficient, large-scale renewables out of a fair share of the RPS market. The effect, in a competitive market, is to bias the market to incentivize highly inefficient small-scale solar to the detriment of less costly larger-scale solar.

C. Comprehensive environmental analysis

Any analysis of the environmental impact of the generation mix should include an examination of the least-cost, most efficient ways to get to the desired results. Problematically, the preferential pricing of less efficient solar DG imposes an unnecessarily high-cost approach to reducing carbon. Results such as that cannot be justified on the basis of externalities, which are no different between DG and larger-scale renewables. Indeed, it seems probable that overpayments for DG have the effect of squeezing more efficient forms of renewable energy out of RPS markets by using preferential pricing to grab a disproportionate share of the RPS market and driving up the cost of reducing carbon.

In the long run, of course, the inherent favoritism in pricing DG at levels arbitrarily higher than other renewable energy sources does not bode well for either the future of renewables or the objective of efficiently reducing carbon emissions. Discrimination in favor of inefficient resources on a long-term basis is simply not sustainable. The inevitable backlash in both the marketplace and public perception has the potential to sweep away public support for renewable energy and perhaps for strong environmental controls as well, an outcome no one concerned about the environment would want. One of the most notable ironies emanating from the use of net metering to price solar DG is that it will almost certainly lead to changes in retail pricing that will undermine the promotion of energy efficiency. The reason for this is that as solar DG becomes more widely deployed, utilities and their regulators will likely become increasingly concerned with the diminution of revenues required to support the distribution system that is caused by the use of net metering.

Those concerns are derived from the fact that under NEM, when solar DG is being self-consumed at the host premises, no revenues are being paid by that host to the utility for providing what essentially amounts to a battery to supplement their self-generation. Since the costs of the distribution are fixed and not variable with the use of "behind the meter" generation, net metering results in a delta of revenue that is either made up for by non-solar customers or constitutes a loss for the utility. Neither outcome is likely to be satisfactory to either the utility or the regulators. Inevitably there will be ratemaking consequences. That problem is compounded, of course, by the fact that when the excess output of rooftop solar is being exported into the grid the solar provider is

being paid as if he/she was delivering the energy, a service obviously provided by the distribution utility. Thus, not only are solar hosts not paying their fair share of fixed costs, they are, by the operation of net metering, actually taking revenues away from the entity that actually provides the service. From the standpoint of the utility and of the non-solar ratepayers who have to bear the burden of such uneconomic and inequitable revenue allocation, rate design remedies will be sought.

One likely remedy to be proposed is to modify the fixed/variable ratio in rates. While distributions are indisputably fixed costs, regulators have generally divided the recovery of those costs on a different basis. Some have been recovered on a fixed basis, while others have been recovered on a variable, volumetric basis. There are two critical policy reasons why this has been the case. The first is that fixed charges tend to impose a disproportionate burden on low-income households and on customers whose consumption is relatively light. The other reason is that volumetric-based charges send a signal to end users that the more they consume, the more they pay. Stated succinctly, the price signal promotes the efficient use of energy. If the revenue stream to cover distribution costs is diminished through mechanisms like net metering, utilities concerned about revenue requirements and regulators, concerned about reliability will, almost inevitably, shift more costs into non-by passable fixed charges, thus imposing more of a burden on low-income households and, equally important, diluting price signals for energy efficiency. In short, net metering will almost certainly, at some point, serve to both cause cost recovery to be socially regressive, and to discourage energy efficiency. In effect, net metering will likely become a classic case of anti-green pricing.

The anti-green pricing aspect of net metering is also exemplified by the behavioral pattern it incents among solar hosts. As shown on both the California and New England

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graphs above, solar production slacks off and ultimately disappears as demand reaches its peak. Despite that, solar hosts are never signaled through prices that their consumption is no longer being supported by zero-marginal-cost solar production. Indeed, in most cases net metering determines prices on an average-cost basis, even though solar production, even in the best of circumstances, is only available a fraction of the time period used for averaging. Thus, solar hosts are essentially lulled into a pattern induced by low marginal prices, which continue in periods of peak demand, thereby driving the peak demand even higher, a result that is truly perverse, both economically and environmentally. In short, net metering and energy efficiency are simply not compatible.

D. Net metering and energy efficiency are incompatible

Many experts from all facets of the renewable energy discussion will assert that energy efficiency is an important, if not the most important, means to increase carbon reductions. Assuming those experts are correct, it is important to consider the ways in which net metering impacts incentives for energy efficiency. While solar DG and energy efficiency are not inherently anathema, net metering is not compatible with energy efficiency. As discussed above, net metering is a compensation mechanism that causes utilities and regulators to move costs into the fixed category, thereby diluting the price signals that would encourage energy efficiency.

E. Possible federal preemption

State regulators, in setting prices for solar DG, should also be

conscious of the potential for jurisdictional disputes should DG prices cause any dislocation in wholesale markets. Because of the economic distortions caused by NEM, there are some who are calling for DG to be under the control of the Federal Energy Regulatory Commission (FERC) rather than state public utilities commissions' jurisdiction.[3] Unless states begin to remedy the price distortions inherent in net metering, it would be surprising if many aggrieved wholesale generators did not seek relief from FERC. In a somewhat analogous situation, New Jersey and Maryland sought to use state subsidies/mandates to support the construction of new power plants in order to manipulate and/or bypass the PJM capacity market. FERC, in a decision which was later affirmed by the Third Circuit Court of Appeals, struck down the state program by preemption. State commissions that continue to prop up a net metering regime with no basis in either market-based pricing or cost-of-service regulation may well discover the prospect of preemption hanging over them.[4] Further foreshadowing preemption are several other examples of state net metering programs running contrary to federal pricing regimes.

The Public Utility Regulatory Policies Act (PURPA) places an avoided-cost ceiling on power purchases; net metering evades that ceiling. Under net metering arrangements, not only are purchases of excess power mandated at levels well in excess of avoided costs, but they also include a cross-subsidy from non-solar customers for the distribution costs of solar DG providers. Bulk power renewables are subject to all of the rules of the wholesale market, which may include such costs as congestion costs, ancillary services, penalties for no availability, and others. Under net metering, solar DG providers are subject to none of these disciplines. In addition, some wholesale renewable generators complain that the arbitrarily high prices paid under net metering have the effect of attracting enough solar DG providers to fill up the RPS market, so that they

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are being effectively squeezed out of the portfolio entirely.

What is particularly ironic about this effect is that, as noted above, distributed, small-scale solar is the least efficient form of commonly used renewable energy sources in the United States. All of these factors indicate that an increasing number of parties are likely to be motivated to ask FERC to preempt net metering and other state-mandated regimes that allow for unreasonably discriminatory and anti-competitive pricing.

IX. Factors Mitigating Environmental Benefits

Expectations of environmental externality benefits may be the biggest motivator for supporting and subsidizing solar DG. Proponents of solar DG note that solar has zero carbon or other harmful emissions from the process of producing energy. Additionally, to the extent that wide deployment of solar PV avoids the need to invest in technologies that do have carbon and other undesirable emissions, there is an environmental benefit that avoids the social costs associated with pollution. In the absence of legal limits on relevant emissions such costs, solar DG advocates correctly point out, are not captured in the internalized costs of the competing technologies. Therefore, solar DG advocates suggest that regulators and policymakers should take these external social costs into consideration in setting prices for various forms of energy.

The use of external social costs, as opposed to solely the internalized economics of various forms of energy is a controversial subject. Many oppose the use of externalities as a factor in pricing because it distorts the market and makes social judgments economic regulators may not be

empowered to make. In the views of such opponents, the only externalities that ought to be incorporated into pricing are those that are internalized by legal mandate. Proponents of incorporating externalities into rates contend that doing so is the only way to accurately reflect all social costs. They also contend that factoring in environmental externalities is a form of insurance against future regulatory requirements. While this article takes no position as to the merits of incorporating externalities into ratemaking, it will address this issue, on the assumption that at least some regulators and policymakers will look at externalities for purposes of assessing the value of solar DG.

Before delving into this issue any further, it is important to note that the United States Environmental Protection Agency (EPA), whose jurisdiction over carbon emissions has been affirmed by the U.S, Supreme Court,[5] has proposed new rules under Section 111(d) of the Clean Air Act that would, if promulgated, internalize the costs of carbon into electricity ratemaking, so the issue of whether or not to consider the costs of carbon would no longer be debatable. Thus, there is a great deal of uncertainty which, in the short term, effectively strengthens the hand of those who contend consideration of carbon emissions would be a form of insurance against future regulation. In the longer term, however, the likelihood that carbon emissions will be internalized gives rise to very serious questions as to the value of including externalities which, over time may run contrary to the economics of internalized carbon costs. It is also worth noting that there are already several states that have adopted controls on carbon emissions. In those states, it is especially important to make certain that renewable policy and pricing enhances efficiency in compliance, as opposed to confusing means and ends. Regardless, the environmental issue, in terms of solar DG, is

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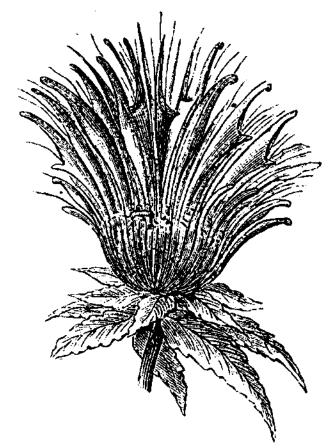
how cost effective such installations are for reducing carbon.

There is little dispute that solar DG is the least efficient of all renewable energy resources in common use in this country. As noted, there is even a consensus, which includes Amory Lovins, that agrees that solar DG is the least efficient renewable resource for reducing carbon. That view is fully supported by the facts in the California duck graph, as well as the ISO-New England and EPRI Value of the Grid data, which demonstrate conclusively that solar DG is consistently off-peak. When priced at net metering levels, it is also the most expensive renewable resource, thereby producing a perverse paradigm that where the least efficient resource costs the most. Therefore, it is evident, without considering any other factors, that solar DG is the least cost-effective use of renewable energy to reduce carbon emissions. There is also the reality that, as a general rule the least efficient and "dirtiest" plants are most likely getting dispatched at times of peak demand. Thus, in the rare instance that solar DG is available at peak in the United States, it is not displacing the most carbon emitting plants. Instead, it is displacing more efficient, less polluting generating units. Moreover, as an intermittent resource, its availability is highly uncertain and fossil plants are often called upon to operate on a less efficient, more carbon-emitting basis than if they were running as pure baseload. Thus solar DG is not only expensive, it is also much more likely to displace low-emitting, more efficient generation than less efficient, dirtier units. In addition, as noted earlier, net metering significantly dilutes the price signals for environmentally benign energy efficiency.



Those conclusions have been borne out by developments in Germany. In that country, where there has been a very dramatic increase in reliance on intermittent energy, prices have risen 37 percent since 2005, and were accompanied by spikes in both carbon emissions and the use of brown coal (lignite). While there are very significant difference between most states and Germany, perhaps most notably that Germany has decided to close down its nuclear plants (although it has replaced much of the domestic nuclear with imported nuclear energy), the experience in that country is very telling.[6] The German example clearly demonstrates that increased dependence on renewable energy resources, particularly intermittent resources, does not, as many solar DG proponents claim, *ipso facto*, mean fewer carbon emissions, and may, in fact, cause the opposite to occur. It also demonstrates that prices will escalate dramatically if the feed in tariffs are as far in excess of market as NEM prices are, as shown by the DTE graph above. The Germans, incidentally, have recognized their miscalculations and are dramatically recalibrating their strategy.

X. Regressive Social Impact

There are social effects beyond the environment that have to be taken into account if externalities are to be factored into ratemaking. Any failure to examine environmental externalities without recognizing that there are other social externalities to be considered as well will yield highly skewed results. Perhaps the most important of those is the social impact.

The social impacts of solar DG are caused by three main factors. First, as noted above, solar DG users have their electricity costs cross-subsidized by their neighbors who completely rely on the grid. Second, some data suggests that solar DG users are unusual electricity users. Third, not everyone can afford to be a solar DG user. To address the second point, unlike typical residential customers, in some regions solar

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DG users use little or no grid power at midday but quickly ramp up demand on peak, when PV production wanes (as is demonstrated by the charts in from the New England and California ISOs). Utilities must be able not only to serve full load on days when solar PV is not performing, but also to ramp up resources quickly to address the peak created by solar DG users. In order to ramp up as needed, utilities will purchase energy at the marginal price and then distribute those costs across all users, not just solar DG users. Thus, users without solar DG may be penalized for the use patterns of their solar DG neighbors. A comparison of residential electricity consumers in the western United States may be found below in **Figure 6**.[7]

Further, the impact of net metering is not simply the creation of a cross-subsidy from non-solar PV customers to solar PV customers but, as has been pointed out in a recent study by E3,[8] it is a cross-subsidy from less affluent households to more affluent ones. Indeed, the average median household income of net energy metering customers in California is 68 percent higher than that of the average household in the state, according to the study. In a recent proceeding, the staff of the Arizona Commerce Commission noted the same consequence.[9] As one wry observer in California noted, net metering is not "Robin Hood" but rather it is "robbin' the hood." In order to install rooftop solar panels, often individuals must be homeowners with high credit ratings or sufficient capital. Leasing arrangements are also widespread, but are generally available only to customers who own their own premises and they require the assignment of most of the rooftop solar benefits to the lessor. Many electricity customers, particularly less affluent ones, do not own homes or lost their homes in the most recent recession. The electricity customers who are unable to afford rooftop solar are forced to subsidize those who are already in a more favorable financial position. Thus, it is entirely fair to characterize NEM as a wealth transfer from less affluent ratepayers to more affluent ones.

Tariffs with a regressive social impact are certainly worthy of consideration from a policy and rate-making perspective. Thus, if externalities are to be weighed in setting pricing for solar DG, then it is important to avoid inordinate cost shifting and, in particular, to avoid adding new burdens to the less affluent in order to provide benefits to those further up on the income scale.

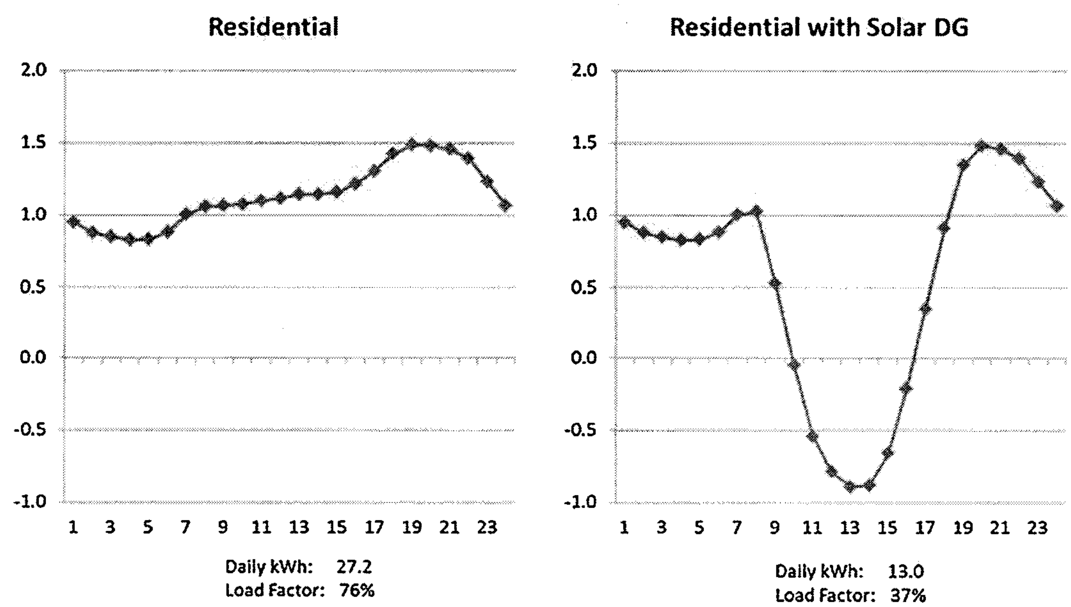

Figure 6: Typical Residential Loads Average Day – Iowa

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XI. Impact on Job Creation

The impact of solar PV on jobs is often cited as an externality benefit. Any analysis of the job impact must be comprehensive and not an effort to cherry pick data. For instance, merely citing the number of solar installers employed does not tell us much. Many aspirations for more jobs manufacturing PV units in the United States have not materialized due to China's capture of the market. Other impacts to be considered are the effect of solar PV on electric rates and the impact of that on the job market, not only in terms of what happens with rates, but also in terms of the rate structure that is implemented as a result of more market penetration by solar DG. For example, it is conceivable that any movements toward more fixed costs could discourage energy efficiency work thus displacing jobs in manufacturing and installing energy efficiency technology.

XII. Conclusion

There is value in solar DG, but that value is severely diminished and placed in peril if its pricing discourages efficiency improvements and distorts critical price signals in the marketplace. It is similarly counterproductive to the future of solar DG if its pricing has socially regressive effects and if it sucks needed revenue away from the essential distribution grid. From an economic point of view solar DG has energy value, the potential for reducing some transmission costs, and perhaps under the right circumstances, some capacity value, and ought to be compensated accordingly. With regard to externalities, it is not entirely clear, when viewed in the entire scope of its impact, that solar DG, has positive environmental value, but it is absolutely

clear that when net metering is deployed, it is simply not a cost-effective means for reducing carbon emissions. In fact, it is possible that solar DG might do more harm than good if it has the effect of removing price incentives for energy efficiency, and if it causes older plants to extend their lives and to operate inefficiently on a ramping basis for which they were not designed. It seems clear that if we are to capture the full value of solar DG, net metering must be discarded and replaced with a market-based pricing system that values the resource appropriately and includes incentives for making it more efficient over the long run.■

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