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**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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| IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN. | DOCKET NO. E-01933A-07-0594<br><br>**NOTICE OF FILING COMPLIANCE** |

Tucson Electric Power Company, through undersigned counsel, hereby files its Final 2009 Renewable Energy Standard and Tariff ("REST") Implementation Plan and Tariff in compliance with and consistent with the revisions of Decision No. 70652.

RESPECTFULLY SUBMITTED this 6th day of January 2009.

TUCSON ELECTRIC POWER COMPANY

By: Michelle Livengood

Michelle Livengood
Tucson Electric Power Company
One South Church Avenue, Suite 200
Tucson, Arizona 85701

and

Michael W. Patten
Roshka DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

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Original and 13 copies of the foregoing
filed this 6th day of January 2009 with:

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

Copy of the foregoing hand-delivered/mailed
this 6th day of January 2009 to:

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG, PC
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012-2913

Peter Q. Nyce, Jr
General Attorney, Regulatory Law Office
Department of the Army
901 North Stuart Street, Room 713
Arlington, Virginia 22203

Timothy M. Hogan
Arizona Center for
Law in the Public Interest
202 E. McDowell Road, Suite 153
Phoenix, Arizona 85004

David Berry
Western Resource Advocates
P. O. Box 1064
Scottsdale, Arizona 85252

Dan Neidlinger
Neidlinger & Associates
3020 North 17th Drive
Phoenix, Arizona 85015

John Kromko
717 North 7th Avenue
Tucson, Arizona 85705

Brian Bozzo
Compliance, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

By: Mary Ippolito

# Tucson Electric Power Company's Renewable Energy Standard & Tariff Implementation Plan 2009 – 2013

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## EXHIBIT 1

## I. EXECUTIVE SUMMARY

Tucson Electric Power Company ("TEP" or "Company") has submitted a Renewable Energy Standard and Tariff ("REST") Implementation Plan for the five-year period 2009-2013. The Plan uses the REST Surcharge ("REST-TS1") (Attachment 1) approved by the Arizona Corporation Commission at an energy rate amount of $0.008000 per kWh; and caps the monthly payment for a residential customer at $4.50, a small commercial customer at $75.00, a large commercial customer at $350.00, and an industrial commercial customer at $1,600.00. The Plan describes the renewable energy resources capacity that may be added during the next five years, the annual energy expected to be produced from these resources, estimated customer funding and tariff amounts required to support acquisition of those resources in 2009, and a 2009 program budget. The REST annual renewable energy requirement begins at 2.0% of total retail sales in 2009, and requires a minimum of 15% of the renewable energy to come from distributed energy sources, of which at least 50% (7.5% of total renewable energy) must be from residential customer sources.

As a separate document associated with the Plan, the Company is filing a Renewable Energy Credit Purchase Program ("RECPP"), which includes nearly all of the preliminary recommendations (with the exception of the increased incentives mentioned above) reached by an informal Uniform Credit Purchase Program Working Group ("UCPP Working Group" or "Working Group") established by Commission Staff during 2006. RECPP addresses the participation process for a wide range of customers, incentive levels, eligible technologies and system requirements.

TEP currently estimates the cost of the approved Plan, to be $29.7 million in 2009, increasing to $65 million by 2013, with a five year total of $248 million. REST funding is intended to cover the cost of utility-scale renewable generation in excess of the market cost of conventional resource alternatives, incentive payments for distributed energy resources, marketing expenses, and program implementation and administration costs. The above-market costs for renewable generation are based upon TEP's current understanding of that market as derived from bids received as a result of a request-for-proposal ("RFP") for renewable energy, as well as extensive discussion with renewable energy vendors and installers. The costs for distributed generation incentives and the program budget are based upon incentives developed as part of the Commission Staff's Working Group and TEP's best estimations of market uptake for the various technologies available to its customers. Annual increases in the program budget are driven mainly by the annually increasing energy targets.

Lastly, experts agree that the future success of renewable energy depends on advances in technology and research. For this reason, as a part of this plan, TEP is allocating funding for renewable research at University of Arizona in partnership with AzRise (Arizona Research Institute for Solar Energy).

## II. PLAN COMPONENTS

### A. Renewable Energy Requirements

The REST Plan has been created in response to the requirements of Arizona Administrative Code R14-2-1801 through R14-2-1815, formally known as the REST rules. The Plan's main purpose is to present the renewable energy purchase and development plan as TEP's Plan portfolio and tariffs. TEP has prepared this Plan for the five-year period 2009-2013. REST requires that affected utilities satisfy an annual renewable energy requirement by providing a percentage of their retail electric energy sales from renewable resources. The required annual renewable energy percentage for the first year of implementation of this Plan begins at 2.0% in 2009, and increases .50% annually to 4.0% in 2013.

Renewable resources under this rule include "renewable generation" projects, which are constructed solely to export their energy production to the utility, and renewable DG, which is a renewable resource application acquired, installed, and operated by customers on their premises that is used to displace the customer's energy consumption. As part of REST, the energy generated or displaced by DG is applied towards the percentage of the utility's distributed renewable energy requirement. To determine compliance with REST, the metric used to track energy in kilowatt hours ("kWh") derived from renewable resources is the Renewable Energy Credit ("REC"), with one kWh equaling one REC.

Meeting REST requirements presents all affected Arizona utilities, including TEP, with a number of uncertainties going forward. Given the needs of our neighboring states to meet their renewable energy mandates, there could be intense competition for renewable energy sources over the next several years. This competition will add to other challenges TEP faces in meeting REST annual energy requirements. These include the timely completion and energy production from contracted renewable energy sources, availability of qualified contractors to install renewable DG facilities, the number of customers who will opt to participate in renewable DG projects, and, of primary interest to electric utility customers, the further development of technology to make renewable energy sufficiently affordable and reliable. Risks also include issues such as: the availability, level and consistency of federal, state and local incentives; the availability of renewable energy projects executed by financially and technically sound developers; the availability of adequate transmission resources to deliver new renewable energy resources to TEP's load; the availability of renewable energy projects matching TEP's anticipated cost profiles; the timing of new resource availability; and the ability of DG technologies and technology providers to serve the needs of customers. TEP acknowledged the risks identified above and attempted to account for them in its Plan. The timely delivery of energy from renewable resources is critical to TEP's compliance with the energy targets; development of these types of projects typically requires between two to five years. Recent experience across the nation indicates renewable generation projects suffer from high levels of project failure, broadly summarized as the inability to meet contract energy delivery dates. These failures and delays can be attributed to a broad range of issues, but are generally attributed to the immature nature of the renewable resource markets. Published experience with renewable energy projects in California suggests that a minimum overall contract failure rate of 20-30% should generally be expected for large solicitations. TEP has attempted to develop an implementation plan that assumes a slightly lower level of project failure rate to that observed in California. As a way to buffer against these risks, TEP's experience with both renewable energy projects and with conventional energy technologies suggests that careful project screening can reduce, but not eliminate, some of the risk associated with project failures. Consequently, the Plan is general in nature and not specific with regard to the mix of resources to be used to meet REST requirements in 2009.

Utilities, such as TEP, that are affected by REST rules are required by A.A.C. R14-2-1813(A) to file an Implementation Plan each year for review and approval by the Arizona Corporation Commission ("ACC" or "Commission"). The Plan must describe the procurement of renewable energy resources for the next five calendar years that will meet the requirements of REST. This description must identify the considered technologies, the expected schedule for the resource incorporation on a year-by-year basis, and a description of the kilowatts ("kW") capacity and kWh of energy that are expected to be added to the TEP generation portfolio by the incorporation of those renewable energy resources.

## B. Development of Renewables in TEP's Service Territory

### 1. Resource Planning

TEP has historically recognized that long-term resource planning is an essential element in determining both supply and demand-side elements of energy production and delivery when making decisions regarding construction of new generation and transmission assets. Beginning in 1994, TEP has studied numerous cost-effective alternative energy sources to meet the growing energy needs of its customers. TEP's long-term resource planning process is an integral part of the renewable energy planning and goal setting process. The forecast of annual kWh of energy and kW of capacity from renewable energy resources by technology to meet REST goals is listed in Attachment 2.

TEP initially considers self-build renewable energy options in the cost evaluation portion of the planning process, but does not include them as a criterion in determining the need for renewable generation options. Purchased renewable power allows for greater flexibility in use of scarce financial resources in developing renewable generation resources, which are typically priced above the Market Cost of Comparable Conventional Generation ("MCCCG"). Purchase of renewable energy allows TEP to more effectively use its resources in developing renewable energy for its customers through partnering with renewable energy developers. Thus, it is an essential element in the Company's generation portfolio. However, cost-effective self-build renewable energy options will be pursued as an alternative to purchased renewable energy, if necessary. TEP plans to purchase all of its non-DG renewable energy from its existing fleet of wind and solar generation systems and its landfill gas-to-energy facility. TEP will utilize , if purchased renewable energy supplies are insufficient to meet REST requirements, RECs from its bank, created during the Environmental Portfolio Surcharge ("EPS") program, to meet REST requirements.

TEP uses an Independent Monitor to review the request-for-proposals ("RFP") evaluation criteria and process to ensure a fair and equitable RFP evaluation is performed in comparing bids against each other as well as against the MCCCG.

## 2. Market Cost of Comparable Conventional Generation

MCCCG, as used in the evaluation of renewable energy bids and as used in the context of determining MCCCG costs of purchased renewable energy for recovery in the REST Adjustor Mechanism calculation, is determined from market costs based on bids received from the Company's pending purchases of conventional energy sources RFP process and/or the cost of TEP's generation. This depends on the type of purchased renewable generation resource (firm, non-firm, dispatchable, etc.) and the market conditions at the time of the renewable purchase.

This MCCCG portion of purchased renewable energy resources is recovered under the REST Tariff as determined in the REST Adjustor Mechanism calculation, whereas the portion of the cost of the renewable energy purchased that is at or below the MCCCG is recovered in the base generation rates. Therefore, precise MCCCG of purchased renewable generation is important for proper allocation of generation costs.

REST's annual increases in renewable targets suggest that renewable generation resources can be developed and procured in increments sized to match annual increases. However, a utility's ability to add renewable resources in amounts that specifically match the requirement is unlikely. Therefore, in some years the renewable generation procured will exceed that specifically targeted; these excess additions are sometimes referred to as "non-linear additions." As such, it is important for the Commission to realize that the procurement of renewable generation is similar to that of traditional generation in this "non linear" process. To receive the most competitive prices, the procurement of generation resources is based on the purchase of blocks of energy (MWh) and capacity (MW) at a specified price. As mentioned above, in some years the company will exceed the target and, therefore, the costs; while in other years, the opposite will occur.

An MCCCG definition and matrix document was developed to determine the applicable market conditions and the type of the purchased renewable generation resource for which the MCCCG is to be evaluated. The matrix is based on the renewable energy technology type employed and market conditions, along with dispatch conditions at the time of the production of the renewable energy under evaluation. The MCCCG calculation will be dependent on the hour of the day, the season of the year and the month. The MCCCG will be evaluated for true up as part of the REST Adjustor Mechanism calculation at the end of each year by running TEP's PROMOD model software against the purchased renewable generation costs. As discussed above, the cost of the purchased renewable generation above the MCCCG costs will be included in the REST Tariff as determined in the REST Adjustor Mechanism calculation.

To determine the MCCCG of the renewable energy options, TEP undertook a study that applied the matrix to the 2006 actual generation market conditions, and proposed generation profiles of wind generation and round-the-clock generation bids received in 2007. The evaluation resulted in MCCCG values for each of TEP's meter billing periods. These hourly MCCCG values were then applied against the hourly generation profiles for the three lowest-cost option renewable generation proposals offered in response to TEP's 2007 RFP for renewable generation In 2008, during the negotiations for the 2007 renewable generation bids, the Arizona wind bidder dropped out of the process. TEP has issued another RFP for renewable generation in 2008.

## 3. Transmission

All of the wind renewable energy resources evaluated for MCCCG are located at least 150 miles from Tucson. Thus, transmission on existing or new lines will be required to bring the energy from these resources to the customer loads in Tucson. Nevertheless, TEP believes the REST goals for 2008 through 2010 are not of large enough magnitude to require additional transmission installations to support purchased renewable power delivery to TEP planned under the Plan. However, it is very likely that the resources needed to meet the 2011 and future REST goals of TEP will require additional transmission line installations. Starting 2009, TEP anticipates network service agreements with third parties, or resource displacement strategies to achieve the targets, between the windy areas of Arizona north of the Mogollon Rim and the Tucson population center. TEP is currently evaluating the 2007 wind generation bids for available transmission capacity. Included in the Plan are transmission service costs of $480,000 for third party network service agreements and a fourth-quarter in-service date. For years 2010 – 2014 $1.9 million is included in this plan. It is important that the transmission planning process include the needs for moving renewable energy from the resource sites to the population centers. It is also important that the Commission include recovery for transmission of renewable energy delivery and regulation expenses. In some cases, as discussed below, strategically located energy storage could mitigate the need for additional transmission once that technology is mature and economical

As TEP transitions to a low-carbon, sustainable-generation portfolio with energy storage over the next 100 years, while supporting continued customer growth and the transition of transportation technologies from a base of fossil fuels to electric energy based sources, there may be an increased need for additional transmission capacity from the more remote areas of Arizona, where wind generation and central solar generation is most cost effective, to the population centers. However, effective use of optimally-located energy storage, in combination with the location of central solar generation at the sites of existing power plants and customer sited renewable generation, could reduce the need for additional transmission. Further study and evaluation is needed in this area.

## 4. Renewable Generation Integration Management

There are costs associated with the integration and load balancing of intermittent renewable resources such as solar or wind. The current lowest cost renewable energy resource available to TEP is wind generation. Many studies have been published regarding the costs of integrating wind generation into a utility generation portfolio, most recently by Idaho Power, citing a cost of over $10 per MWh for integration, using hydro generation resources for balancing. Studies performed by TEP, which have been recognized by a recent $100,000 grant award from the Department of Energy to develop evaluation methods for determining the capacity value of solar generation to utilities, indicate that solar generation without some integrated energy storage – both central plant and distributed – has a much greater time-variant percentage fluctuation in output than wind generation over the same time frame. Preliminary studies by TEP and Carnegie Mellon University indicate geographic diversity is not as effective in reducing the high level of variation in the output of solar generation as it is for the output of wind generation. While the cost study for integration of solar energy into a utility generation portfolio is not yet complete, TEP does not expect that the cost of managing the integration of both time-variant renewable generation sources, solar and wind, will be more than an insignificant factor until the year 2011 (based on the lower initial REST annual energy percentages in the early program years). TEP will use the data taken in the years prior to 2011 to evaluate the cost impact of integrating wind and solar generation with its existing fueled generation portfolio. After 2011, TEP expects to include a factor for recovery of integration costs in its REST Tariff through the REST Adjustor Mechanism, and thus requests approval of that factor, not the amount of the charge, at this time.

## 5. Distributed Generation

REST requires that affected utilities satisfy a percentage of their annual renewable energy requirement through the addition of distributed energy resources. The required DG percentage in 2008 began at 10% of the 1.75% total requirement and for the current implementation period begins at 15% of the 2.0% total requirement in 2009, and increases to 30% of the 4.0% total requirement in 2013. That percentage remains at 30% of the total renewable energy requirement through 2025.

Considerable public discussion has surrounded the DG targets described in REST. This discussion has centered on questions related to the magnitude of customer interest in DG, the effect of introducing many new distributed technologies, the ability of the technology suppliers and installers to meet the potential customer demand, long-term reliability of these technologies and, ultimately, the total cost of incentives required to drive the required customer participation to meet REST compliance. The extent of customer participation is the primary driver of DG results and it is simply unknown and unknowable at this time. TEP's six years of experience with its SunShare Incentive Program demonstrated that changes in public policy affecting the program (i.e., state and federal tax incentive increases) and changes in program incentives can have dramatic impacts on customer participation, in some cases beyond those anticipated and positive results can be location specific. There is virtually no way to accurately predict whether the amount of incentives being offered will motivate customers in all parts of the service territory to participate at the necessary rate for full REST compliance. This is particularly germane, because even with availability of significant incentives, customers must still provide significant personal funding in order to have DG systems installed on their homes or businesses. Today, the typical residential distributed photovoltaic system costs about $21,000 to install, attracts about $10,000 in government and utility incentives, and requires a customer investment of about $11,000.

TEP recognizes that DG is an important component of the renewable energy goals of REST. TEP recognizes that uncertainty exists with respect to the proposed incentive levels and the total number of RECs that they will generate; however, in order to comply with the DG targets, TEP believes this funding level is necessary if consumer demand for DG is to be sufficient to meet the REST DG annual energy requirements. The assumptions used to build the DG program budget are based on incentives developed as part of Commission Staffs UCPP Working Group, market insights from those same meetings, and TEP's experience with its SunShare Program modeled with customer payback term scenarios with current federal and state incentives. TEP expects in this Plan to purchase all REST DG credits through its GreenWatts SunShare program offerings, as described in the RECPP program below.

TEP believes that customer-sited renewable DG systems are part of the long-term goal of a sustainable, Arizona self-sufficient energy supply for its customers. Thus, a Renewable Energy Credit Purchase Program incentive program, the TEP Renewable Energy Credit Purchase Program ("RECPP") is to be offered for our customers who install and operate renewable DG systems.

TEP implemented Arizona's first true net metering program, approved by the Commission in 2000, in combination with Arizona's first utility-sponsored solar energy system rebate program, SunShare, approved by the Commission in January 2001. While development of distributed renewable generation will reduce TEP's need to produce electric energy from fossil fuels to meet its customer's energy needs, central or distributed solar and wind generation have demonstrated over five years of TEP renewable energy production and SunShare experience that they are not able alone to meet the firm capacity or voltage control requirements essential in providing safe, reliable electricity service to all of our customers. Historic data indicates there is nearly zero firm capacity benefit on an annual basis from the installation by Tucson-based customers of distributed solar and wind generation systems to TEP at the time of annual peak loads due to typical monsoon conditions that drive the peak loads, yet generally cover the sky with clouds as the loads peak.

There are both additional benefit factors as well as additional cost factors to TEP from customers installing and operating renewable DG systems at their homes or businesses. Distributed Generation can provide benefits to both the customers owning the DG as well as to the utility in whose distribution system the DG has been installed. There are also costs from the installation of DG to both the owner of the DG and the utility. If the DG output is not time-variant, the benefits are demonstrably higher and the costs lower to both the DG owner and the utility. However, if the output is time variant or is a function of weather patterns which can affect peak utility system demand, such as monsoon cycles, the benefit of the DG for firm capacity support is significantly reduced. Other benefits include: (1) reduced line losses, (2) increased life for current induced heating devices like transformers, (3) reduced water consumption at generating plants, (4) reduced emissions from conventional generating plants, and (5) reduced impact from the recovery and transportation processes used to provide fossil fuels for conventional generating plants.

Costs of DG to the owner include the cost of any required fuel, operation and maintenance costs ("O&M"), initial installation costs and ownership costs including financing, taxes and insurance associated with ownership of a generation system. There are also costs to the utility, including: (1) the increased need for rapid response automatic voltage control and load management devices in the distribution systems, (2) increased hardware to provide proper protection to distribution circuits with high percentages of DG installed, (3) additional repair time after a storm to clear DG sources prior to start of work, (4) increased outage recovery time from uncontrollable (to the utility) DG resources that start generating automatically in an unpredictable manner, and (5) lost revenue from the reduced sales of electricity with consumption-only based rate structures. The quantification of these benefits and costs is very much utility-specific and of fairly low magnitude at the low levels of DG penetration expected in

2008 through 2010. While accurate, valid data is also difficult to obtain at low levels of DG penetration, over time as DG installations increase, the data quality and quantity will improve and benefits and costs of renewable DG will be accurately quantified.

Net metering programs provide an added benefit to the DG owner by providing a credit at the retail rate for generation output produced in excess of use over a given time period. For time-variant non-dispatchable DG systems like solar or wind, this can be a large benefit as DG output cannot be easily scheduled by the owner to match demand. Utilities can positively impact a decision to install DG by offering net metering programs for time-variant DG systems and by eliminating or reducing the cost of the interconnection to the utility grid. Utilities can also positively support installation of DG by eliminating or reducing backup capacity and energy fees, charged to a DG customer when the DG system is not operational for planned or unplanned reasons. Utilities positively support renewable DG systems, such as solar generation, through providing rebate programs to reduce the initial cost of a DG system or through providing production-based REC purchase programs to provide an ongoing revenue stream for the owner to offset O&M and ownership costs.

Utilities receive a benefit from DG systems primarily from dependable reductions in peak annual demand from the generation output of DG systems during high load demand hours. Firm, guaranteed reductions in peak demand allow utilities to reduce requirements for building generation, transmission and distribution capacity. However, if the DG generation is not firm and guaranteed to a very high degree of confidence over many annual load cycles, the utility cannot reduce its planned capacity requirements from customer installation of DG. Utilities will benefit from fuel use reductions and reductions in distribution losses through DG installation, effectively the variable portion of energy production expenses. There can also be a benefit to utilities from an increase in operational life for various distribution components, such as transformers and underground cables whose life is reduced by operation at elevated temperatures, created in part by high electrical loads. However, this benefit is also heavily dependent upon the ability of the DG to provide firm, highly reliable output during the highest load demand hours of the year. Thus, to a utility, the benefit of DG is a very large function of the capacity credit assigned to a generator based on its proven ability to provide electrical generation output during the peak load demand hours of the year for that utility.

The costs of renewable DG to a utility include the direct cost of any rebates or production payments made for renewable generation, as well as internal and external labor or consultant costs of reviewing interconnection plans and providing interconnection devices to DG installers. However, in many cases, the largest cost to a utility from installation of DG systems is lost revenues from energy-only based utility rates, as a DG system reduces the energy consumption of the owner. The DG owner still must have a distribution drop to their premises, the distribution, transmission and generation capacity must still be available to support demand, the meter must still be read and bills prepared, remittances processed and administration of the utility provided.

A time-variant DG system does reduce utility annual fuel use and line losses in the distribution system. However, since the energy based utility rate DG owner uses less energy per billing cycle, that owner will be providing reduced amounts of revenue to the utility to compensate for those services which the utility is obligated to continue providing and the DG owner requires for continuity of service. This can be addressed through partial requirements tariffs, backup service charges, an increase in the monthly fixed service charge and other rate mechanisms designed to provide a decoupling of the fixed cost of providing electrical service from energy production-based related charges. Decoupling of rates from consumption can reduce this negative impact and more closely align the financial interests of customers and utilities for support of self-generation.

Time-variant DG output would appear to a utility control system as variable negative load. If the amount of DG output variance exceeded the amount of load variation normally experienced by the utility, it could result in the need for additional high-ramp rate peaking generation or storage capacity, beyond what would be required without the time-variant DG installations. The cost of installation and operation of natural gas-fired high-ramp rate capability firming generation, or electrical energy storage is an additional cost to a utility for support of time-variant DG sources in its service territory. The installation of rapid change, time-variant DG, coupled with the current inability of solar generation systems to provide reactive power, may also adversely impact the ability of existing utility voltage control devices, primarily slow response capacitor banks, to adjust reactive power flows to support local distribution system voltage in a sustainable, reliable manner during cloud passing events. Additional grid regulation support requirements, such as low-voltage ride through, droop support and frequency-stability regulation, are not currently provided by grid-connected solar generation systems, and will consequently need to be provided in greater quantities by utilities in the future, with the associated cost of installation, maintenance and operation of these control devices recovered.

Due to the relatively small amount of renewable DG installed in any North American utility service territory, there is not sufficient verified cost data to accurately and unambiguously determine the cost or benefits of renewable DG to TEP. Therefore, TEP does not propose an allowance for indirect costs or benefits of renewable DG be applied to increase or decrease the expenses TEP will incur in offering a renewable DG incentive program at this time. The REST Adjustor Mechanism will reflect recovery of all actual direct expenses of the renewable DG program. In the future, as verifiable cost and benefit data is available from renewable DG programs with significant participation in the TEP service territory, the Company will apply those indirect factors to the REST Adjustor Mechanism value calculation.

## C. Required Program Funding

The Plan is estimated to cost a total of $248 million over the five-year period covered by this Plan. This Plan is designed to achieve compliance with the REST requirements. The cost for the first program year is estimated to be approximately $28.9 million and increases to $65 million in 2013, driven mainly by the increasing energy targets. TEP is has designed a REST Tariff to recover the estimated 2009 costs of approximately $29.7 million. In each succeeding year, as part of its Plan, TEP will request a reset of the adjuster to collect the estimated costs for the following calendar year and true up revenue received and expenses incurred for prior REST program years.

Several of the attachments contained in this Plan include pricing estimates that have been made in development of the program costs. Some of the pricing included in this Plan is pricing from existing confidential proposals. The price estimates are necessary to allow TEP to provide the information sought by the Commission as part of the background and support for the Plan. In addition, summary expenditures and energy requirements for generation provided on a year-by-year basis could be used to infer much of the confidential pricing information. TEP believes it is in the best interest of the Company and its customers to ensure that future suppliers of renewable resources compete for the right to supply renewable energy without a pre-conceived notion of the pricing assumptions or confidential pricing in this Plan.

## III. 2009 TEP REST

### A. Energy

The minimum annual percentage of a utility's retail sales that must be obtained from renewable resources is identified in REST; the Plan's first-year target for 2009 is 2.0%. The renewable resource targets required to meet TEP's targets for each year of the Plan are detailed in Attachment 2. REST targets are described in two categories, renewable generation and distributed generation resources.

Renewable generation consists of projects that export their energy production to the utility. These projects are typically large-scale facilities that use renewable resources such as wind, solar, geothermal, biomass, and biogas to generate electricity. Energy produced from those resources is delivered through transmission and distribution systems and, ultimately, to the utility's customers.

Distributed generation resources represent technology applications that are physically installed on the customer's property. These applications are usually designed specifically for the distributed setting. Distributed applications under REST would include a wide range of technologies; these technologies are currently most frequently represented by photovoltaic and solar water heating systems. The DG displaces some of the customer's energy needs, and can be tied to the existing TEP distribution system or installed as a remote application independent of the TEP distribution system. TEP does not plan to install DG at customers' properties other than through our GreenWatts-funded community leadership sited projects; rather, the installation of DG is facilitated by providing customers with financial incentives for the installation of such resources by licensed contractors.

### B. Capacity

There are no capacity requirements (in kW) in the REST targets, but rather requirements are energy-based (kWh) only. However, this Plan utilizes historically-based generation capacity assumptions to forecast compliance with the energy targets. When one equates energy targets to planned capacity levels, it is important to recognize that the capacity factors for various renewable-generation technologies vary significantly. Some technologies, such as biomass and geothermal, are predictable and can produce energy at capacity factors of approximately 80-90%, similar to conventional-base load generation. Other renewable generation technologies, such as solar, are less predictable and have inherently low capacity factors of 15-30%, which are driven by daily fluctuations such as the availability of solar radiation and are influenced by location. There are other renewable generation technologies, such as wind, which are less predictable on a real-time basis. On an annual basis, however, wind will generally produce capacity factors in the range of 25-35%, depending upon the characteristics of the wind resource in a specific location.

A key factor in reaching a target, therefore, is the combination of technologies utilized, and the ultimate mixture will dictate the additional capacity required to achieve the energy targets. Attachment 2 provides the level of capacity for the specific mixture of technologies assumed in the Plan for the coming five years. This Attachment is not intended to be an exact representation of the resources TEP intends to acquire, but rather is offered as an example of a potential resource mix, based upon TEP's current understanding of the marketplace. The economics of a particular technology or resource will ultimately determine the extent to which any one technology is employed as part of the overall portfolio's content.

## C. Renewable Generation

This Plan has been designed for sufficient flexibility in order to provide the maximum opportunities to meet or exceed the REST target at a reasonable cost. The following sets forth descriptions of the expected resource additions over the next five years:

### 1. Existing Renewable Generation

TEP presently has no power purchase agreements ("PPA") for renewable generation resources. However, TEP owns and operates approximately 5 MW of solar capacity and has a contract to purchase landfill gas in amounts up to 5 MW equivalents.

### 2. Renewable Generation Procurement Plan and Process

Energy required to meet the TEP targets and the anticipated demand for renewable rates in each of the next five years is outlined in Attachment 2 to the Plan. Generally speaking, two to five years is required from the initiation of a project via an RFP to the point at which energy can flow into the TEP system from a completed renewable generation project. The development and construction of the project itself accounts for the majority of that time period; therefore, an RFP process started in 2007 may realistically be expected to result in producing renewable energy applicable to the renewable resource target in 2009, at the earliest during the third or fourth quarter.

TEP estimates that it will need additional amounts of renewable energy commencing in 2008, in addition to that which has already been built. As a result, TEP implemented a competitive procurement process in 2005, 2006, 2007, and most recently in 2008. The competitive procurement process consists of, but is not limited to, the issuance of RFPs, negotiated bilateral supply contracts, and other competitive solicitations seeking long-term renewable resources. Implementing an effective competitive procurement process will ensure a fair and unbiased procedure that will efficiently incorporate a full range of renewable resource alternatives from the marketplace.

During the evaluation of submitted bids from the competitive procurement process, TEP's review of proposals will include analysis of: energy production; capacity value; deliverability; technical characteristics; operational performance; reliability; efficiency; credit worthiness; grid impact mitigation; and respondent experience. The procurement and project selection procedure employed by TEP has been documented and certified to be fair and appropriate by an independent auditor as required by REST.

TEP's Plan attempts to fully acknowledge the reality that PPAs and project development methods will not necessarily conform to required delivery schedules and planned quantities. Renewable generation projects, like other generation projects, may fail to achieve scheduled commercial operation. A recent review of renewable projects in California stated that utilities should expect that 20-30% of renewable contracts could experience termination or major delays. Delays or failures of that magnitude could cause TEP to fall short of its renewable energy targets. Thus, such risks require TEP to design and employ contingency measures. In order to prevent energy shortfalls resulting from these risks, a procurement goal of 120% of the target energy for three to five years into the future will be employed.

### 3. Identifying Renewable Generation Requirements

The renewable resource targets increase from 2.0% in 2009 to 4.0% in 2013 during the five-year period of this Plan. The Plan focuses on existing and planned renewable resource projects to meet those targets. It is also contemplated that new renewable generation will be contracted for and developed during that five-year period. It should be noted that TEP has based its program's budget and energy procurement on several assumptions that are mentioned in the discussion that follows.

#### a. Costs of Renewable Generation

The costs of renewable generation are based for the purposes of resource and budget planning upon the portion of the renewable energy cost that is above the Market Cost of Comparable Conventional Generation (MCCCG). The value amount above TEP's cost for comparable generation was established at the time the bids of proposed contracts were evaluated, and that value is applied to the total proposed purchased power cost for the planning year. For future contracts, the price is estimated based upon existing renewable generation contracts, recent market experience, and general trends observed in renewable generation project development. Subsequently, these numbers will be re-evaluated during subsequent five-year planning periods. All renewable resource costs are described in terms of dollars per megawatt hour ("MWh") above TEP's comparable conventional generation values.

#### b. Planned Resource Additions

REST's annual increases in renewable targets suggest that renewable generation resources can be developed and procured in increments sized to match annual increases. However, a utility's ability to add renewable resources in amounts that specifically match the requirement is unlikely. Therefore, in some years the renewable generation procured will exceed that specifically targeted; these excess additions are sometimes referred to as "non-linear additions." As such, it is important for the Commission to realize that the procurement of renewable generation is similar to that of traditional generation in this "non linear" process. To receive the most competitive prices, the procurement of generation resources is based on the purchase of blocks of energy (MWh) at a specified price. As mentioned above, in some years the company will exceed the target and, therefore, the costs will be higher while; in other years the opposite will occur.

The schedule of resource additions provided in Attachment 2 of the Plan identifies specific targeted additions of renewable resources. The planning model incorporates an assumed-capacity factor for each renewable technology. The modeled capacity factors are based on TEP's review of technical performance data for each technology, discussions with project developers, and a review of published information related to currently operating commercial renewable resources.

## D. Distributed Generation

TEP has identified Distributed Generation ("DG") as an important component of the renewable energy goals of REST and, as part of this Plan, TEP proposes a funding level it believes is necessary for compliance each year to support the DG program. TEP recognizes that uncertainty exists with respect to the proposed incentive levels and the total number of generated RECs.

TEP has calculated a level of funding for its REST Tariff Adjuster Mechanism necessary to recover 2009 estimated expenses for the DG ACC approved program. Increases in the adjuster will be required in future years for TEP to meet the DG requirements in REST. TEP believes that adjusting the funding annually allows TEP, working with the Commission, to implement a flexible program with a clear understanding of program performance and costs without over-collecting funds from customers in the near-term or compromising the overall resource goals of this Plan and REST.

The Commission's Staff initiated the UCPP Working Group described in A.A.C. R14-2-1810 in June 2006, and TEP participated in all of the Working Group's efforts. TEP has generally used the approach developed by the UCPP Working Group for the Company's proposed DG incentive program, RECPP. The Working Group has made significant progress towards identifying program workflows, technology-sensitive incentive structures and levels, and technology- specific requirements and limitations. The efforts of the Working Group also provided TEP with insight into the anticipated potential contributions from technologies not previously included in TEP's SunShare programs. Planning models, implementation strategies, and budgeting for the DG program were all designed with specific consideration for the UCPP Working Group's recommendations. In addition, TEP relied on over six years' experience with its SunShare Program, as well as on continuing dialogue with many industry and consumer stakeholders.

In 2009, the ACC has approved a Builder Credit Purchase Program for TEP that integrates the energy efficiency of TEP's Guarantee Home and the renewable energy of TEP's SunShare program to complement REST. Most of the requirements of RECPP remain intact, but simply packages energy efficiency and renewable energy together to move toward the goal of a "net zero" home.

## 1. Anticipated Distributed Generation Program Outcomes

TEP has developed a set of planning tools to help anticipate DG program outcomes, both from energy and budgetary perspectives. In developing the anticipated program outcomes for this Plan, a number of assumptions about technologies and customer preferences were first necessitated. The assumptions included the anticipated number of categorical projects requesting incentives and the anticipated energy contribution from each DG project. Anticipated energy contribution is calculated by utilizing assumptions on average project size and average project production. The detailed assumptions were required for purposes of budget and planning, but are not intended to reflect allocations, funding caps, or preference for any one technology. The energy production assumptions are set forth in Attachment 2 for the Plan.

Included in the TEP RECPP are incentives drawn from the draft UCPP Working Group findings. RECPP is a separate document submitted in general compliance with A.A.C. R14-2-1810.B. RECPP, as generally described herein, details different incentive types for use in the DG program. For planning purposes, assumptions about customer preference for the variety of incentive alternatives were utilized.

The DG budget, combined with the planning assumptions, results in specific outcomes as noted in Attachment 2 for the Plan. The actual results of program implementation may well be different from those anticipated by TEP's planning efforts, as customers learn more about the variety of technologies and applications available as a result of TEP's program marketing, advertising, and partnership-development efforts.

## 2. Key Components of the Proposed Distributed Generation Administration Plan

TEP's DG program is detailed in RECPP. The following describes several key common components of TEP's program as set forth in RECPP.

### a. Administration

Project funding is not guaranteed until a reservation confirmation is provided by TEP for each project. To receive a reservation and an incentive, applicants must follow the established reservation, installation, and inspection procedures.

### b. Equipment and Installation Requirements

The installed DG systems will be required to adhere to generally accepted industry standards, federal, state and local codes, all applicable regulatory requirements, and manufacturer recommendations for installation and operation. Systems must be installed and warranted by an Arizona licensed contractor holding an active certification for the technology being installed, or, in some cases, by a residential homeowner if willing to accept a lower level of incentive.

### c. Incentives

Incentives are designed to defray some of the costs of a system designed to offset a typical load of a customer. Systems qualifying for DG incentives cannot qualify for other utility incentives.

Residential - Customers applying for residential incentives may apply for a one-time payment based upon the DG system's capacity, or based upon the estimated first-year savings provided by the DG system, dependant upon the technology used. This type of incentive is referred to as an Up-Front Incentive ("UFI"). Residential customers can also apply for a production-based incentive ("PBI") as an option, or if their warranty conditions are not sufficient to meet the UFI qualifications.

Non-Residential - Non-residential customers will either receive a UFI or a PBI, which is paid out over time. Projects receiving PBI payments are paid based on system energy output rather than on system capacity. Projects with a capacity less than or equal to 20 kW can elect to receive a one-time capacity based UFI; all others will receive incentives based upon production (a PBI).

### d. Non-Conforming Projects

Those DG projects that fall outside of the standard administrative, equipment, or incentive requirements for RECPP projects, or projects that are solicited by TEP to achieve specific program goals, may be eligible for incentives as non-conforming projects. These projects must be comparable to conforming projects in financial efficiency in order to be considered eligible for incentives.

### e. Customer Self-Directed Option

Per REST, certain interested eligible customers are required to apply and declare the amount of the self-directed funding requested before May 1st of the year prior to the request for funding payment, effectively at least 60 days before the Plan is filed for the upcoming year. These projects must be comparable to conforming projects in financial efficiency to be considered for incentives. The amount of funds allocated to customer self-directed projects will be disclosed in the Plan for the next program year. For 2009, one customer has requested funds for self-directed projects.

### f. Builder Credit Purchase Program Description

In 2009, TEP is proposing to offer a Builder Credit Purchase Program that combines the energy efficiency of TEP's Guarantee Home and the renewable energy of TEP's SunShare program to complement REST.

Southwest Energy Efficiency Project (SWEEP) published a study in November of 2007 entitled "High Performance Homes in the Southwest" which evaluated the energy and cost-savings potential of constructing more efficient new homes in five Southwest States. Although the report reviewed regional policy from a variety of different perspectives, for utilities offering energy efficiency programs for new home construction, SWEEP recommends that utilities offer a 3-tiered incentives package to builders, beginning at ENERGY STAR and going up to a Net-Zero Energy Home level of performance.

Tucson Electric Power proposes to follow this recommendation by adding a program at the "Net-Zero Energy Home" level. This would provide a distinction for builders who are early adopters of new technologies and embrace high performance as a goal throughout their design process. For builders to effectively reach this level, it is necessary to incorporate certain goals at an early stage in the plan development. It is understood that initial participation at this level would be modest. However, it is important to set this goal significantly above current building standards to set a milestone for market transformation.

Program highlights include:

- Participation in TEP's new home program.
- Builder may choose solar thermal or PV or both with an increased incentive of $0.50 per DC watt installed for PV. (No increased incentive for solar thermal.)
- Builder has the option of certifying their subdivision as a LEED for Home with TEP providing Manual J calculations, HERS Rating services and technical consultation.
- Savings for consumers, when using both the solar energy and very efficient building practices, can exceed 60% over standard building practices.
- By providing incentives during construction, the price of the solar system is then absorbed in the mortgage. This allows the consumer to utilize the generation of the PV system to offset the increased mortgage cost to create a better cash flow scenario.
- Provide up front installation of net meters, along with training and education of homeowners, to set proper expectations of system performance.
- Coop advertising with the builder focusing on the benefits of combining both energy efficiency and renewable generation.
- The program provides inspections and testing at each home to ensure quality installation by homebuilder's subcontractors. This includes all of the requirements for a HERS rating as well as a verification of renewable technologies.

### 3. Distributed Generation Incentive Budgets

TEP's initial DG incentive budget for the five-year planning window is described in Attachment 3 to the Plan. The incentive budget for the Plan allocation is designed to result in half of the distributed energy to be from residential installations and half from non-residential. Annual increases in program budget are designed to accommodate both an increase in the DG energy target and to account for the increasing levels of commitment to PBIs, which are used primarily for non-residential DG resources. The incentive matrices incorporated as part of RECPP describe incentive reductions every two years of the program. Those planned reductions were designed by the UCPP Working Group to reflect the anticipation that DG technologies will decline in cost as market penetration and product availability increase. Three specific allocations are described in RECPP for the Plan. They include: non-residential UFIs; non-residential PBIs; and residential UFIs.

The RECPP describes potential funding for customer self-directed projects. As part of the RECPP, a budgetary earmark is required in order to fund projects meeting the criteria of customer self-directed projects. For 2009, one customer has requested funds for self-directed projects.

The annual funding level for DG incentives was established based upon the estimates of the renewable energy needed for compliance, anticipated consumer demand, projected sales and development time frames, variations in the levels of technology maturity, and availability of equipment for installation. Should it happen that funds collected for use in the DG incentive program are not fully subscribed within a program year, those funds will be applied to the next program year and allocated to achieve the required energy outcome between residential and non-residential projects. Those over-collected funds would reduce the amount of the REST Tariff (Customer Self-Directed Tariff "REST-TS2") in the subsequent year.

## 4. Marketing, Advertising and Partnership Development

TEP is committed to conducting an action-oriented marketing campaign that will not only inform and educate consumers about the importance of renewable DG and its potential benefits to customers and the community at large, but also spur them into investing in renewable energy.

Education and community awareness are the catalysts for the shift in public attitude required to jump-start the robust solar energy market envisioned by political leaders and DG advocates. Information is the prerequisite in achieving real movement toward alternative energy solutions. But fostering enhanced knowledge on the subject is not enough; ultimately, the goal is to proliferate solar and renewable energy DG in the Tucson metropolitan area.

The marketing campaign will take a three-pronged strategic approach: 1) identify key stakeholders and analyze their specific interests; 2) educate those stakeholders (such as residential customers, business owners, students and opinion leaders) about the nature and benefits of DG; and 3) create marketing messages that encourage customers to take action, while promoting incentives designed to make DG an attractive choice for customers to reduce their carbon footprint.

The following key marketing components are designed to bring DG into the mainstream:

- Create an actionable campaign that focuses on the benefits, improved reliability and environmental impact of DG; cause consumers to see DG in a whole new light.

- Utilize media that will best reach our various stakeholders through both paid and public service messages, as well as earned media.

- Develop collateral pieces for both residential and non-residential customer acquisition.

- Heavily promote the DG program on www.tep.com and through customer communication vehicles such as bill inserts, e-newsletters and bill messaging.

- Maximize participation in green expos and other targeted community-wide events.

- Create and promote solar-based educational programs for the schools.

- Identify and solicit the support of "change agents" in the community who can effectively influence key stakeholder groups.

- Partner with various media outlets and vendors to develop co-promotions based around distributed generation; provide supporting collateral such as site signage and counter displays for added promotional support.

- Expand partnerships with area solar installers by continuing to provide technical expertise and collateral materials as well as sharing industry news and product updates.

- Escalate TEP's involvement in the community dialogue about energy sustainability, lending expertise and experience through existing networks, ranging from classroom presentations and demonstration projects to interaction with environmental organizations and homeowner associations.

TEP has been widely recognized for many years as a leader in the development and installation of solar energy systems. As a byproduct of that leadership, TEP has cultivated relationships, and acquired industry intelligence, that can now be applied to the propagation of DG in the Tucson area.

The previously described marketing components are based on currently available data. As the campaign proceeds, TEP staff will monitor and analyze results, and will consider modifications to the campaign that mitigate deficiencies or capitalize on successes.

## E. Implementation and Administration

As part of the development of a strategy and budget for REST implementation, a logical separation was created between 1) those elements required to support the renewable generation portion of the program, and 2) the DG portion of the program. Renewable generation involves expertise in utility-scale technologies, competitive procurement and evaluation processes, project siting, utility integration, transmission- and distribution-related issues, complex contract negotiations, and contract management. The DG program will be a mass-market program involving thousands of individual interactions requiring customer communication, interconnections, inspections, customer billing, and a sophisticated system to monitor REC production. Certain TEP resources will be used to support both portions of REST, as discussed below.

## 1. Resources Required for the Renewable Generation Program

A renewable generation program requires knowledge-area experts to identify those aspects of renewable generation procurement, engineering, and market analysis that are unique from those same areas in conventional energy operation, and to coordinate with the impacted operational areas of TEP in order to seamlessly integrate renewable resource management into TEP's standard utility business practices. These experts comprising the renewable generation administrative team include the personnel necessary to manage the program, which incorporates establishing policies and procedures, procuring renewable generation, handling contract administration and construction management, managing benchmarking and resource integration studies, and performing program monitoring and compliance reporting.

There are also TEP employees supporting the program that are neither part of the administrative nor the implementation teams. These personnel are considered "non-incremental" and are required to support the general operations of the utility and have responsibilities that are not directly related to the DG program. These would include, but would not be limited to, employees within TEP's regulatory, pricing, accounting, legal, contract administration, and meter reading areas.

## 2. Resources Required for the Distributed Generation Program

The implementation strategy for the DG program was developed with the following goals:

- Develop an accurate, efficient and customer-friendly process.
- Integrate the program's processes into the general business operations.
- Create a measurable process that responds to adjustments in the volume of program participation.
- Support the strategic marketing efforts of the program.

In order to accomplish these goals, a significant investment in program implementation and management is needed. The DG program represents a significant number of individual transactions, and each transaction impacts numerous parts of TEP's business infrastructure. Thus, implementation costs for the DG program are significant.

### a. Program Resources

The program's personnel team is comprised of the human resources necessary to execute the DG incentive program. This includes the fixed-payroll personnel required to administer the reservation and interconnection applications and agreements, review system design for conformance with RECPP and interconnection requirements, process incentive payments, answer customer and installer questions about the program, and perform field inspections. It also includes the variable-payroll personnel required to program and install net or performance meters, label utility equipment to identify potential back-feed sources, and provide billing support to net-metering customers. Further needed are the employees required to manage the execution of the program, develop and execute the marketing and advertising programs, and provide ongoing program monitoring and compliance reporting. The number of implementation team members required is proportional to both the number of applicants at any one time and the number of program participants. Additionally, just as in the case of renewable generation resources discussed above, many non-incremental employees will also be needed to support the DG program.

#### b. Material Costs

In order to measure the actual amount of kWh returned to the grid by DG facilities, a DG performance meter, as well as a standard utility meter, must be utilized in TEP's system. The incremental cost charged to REST is the total cost of the performance meter in addition to the incremental cost of any net meters added as replacements for the standard utility meter.

The RECPP will capture an annual meter read for all DG systems generating electricity for compliance verification and program evaluation purposes. TEP believes that many customers may also be interested in the ability to tracking total kWh generated by their system. To facilitate both the meter-read capture requirement and to assist customers track the kWh production by the DG system, TEP plans to install and read the system performance meter for all participants in the program. The only costs charged to REST are those costs associated with providing the second meter to record system production. There are also incidental material costs associated with the program including, but not limited to, system locks, tags, inspection tools and transportation for inspection personnel.

TEP may also install an interval-recording meter on a certain number of sites that will be used by load research to conduct studies on the coincidence of solar output vs. TEP system load. The only material cost charged to Plan will be the incremental costs of the interval recording meter.

#### c. Technological Improvements Required

For TEP to effectively and efficiently implement the DG incentive program, it will be necessary to integrate with its existing systems, including: customer billing, the program and operations databases, accounting systems, and dispatch and scheduling tools. This investment is required to ensure integrity and to support the scale of the program as it is described in the Plan. The technology tools to support the distributed incentive program that TEP will develop and integrate into existing systems include:

- Agreement-Processing and Workflow-Management Tools — These tools will provide an interface through the tep.com website to allow customers and vendors to complete and submit all program forms and agreements on-line with data to be stored in a central database. They will include an integrated workflow-management component to provide status tracking, work orders, and scheduling. The tools will also integrate into all major systems, including the billing system, and the operations and accounting databases.

- Performance Information Tools — Readings from the system performance meter will be integrated into the TEP billing system.

- Meter Database Management — Readings from the bi-directional meter will be integrated into the TEP billing system. The credit for the energy sold back to the TEP system will be calculated within the billing system and will appear on the customer's standard TEP bill.

- Reporting and Maintenance — Data capture necessary for ongoing program monitoring and compliance reporting will be facilitated by developing standard reports and a reporting tool for *ad hoc* queries. Database development is underway in 2008.

- Energy Management System ("EMS") Reporting — Upgrades to the EMS system are necessary to capture the system cost of purchased renewable energy on a real time hourly basis.

## F. Renewable Technology Commercialization and Integration

TEP includes a budget allocation in the Plan for studies related to commercialization and integration of renewable resources. The purpose of this budget allocation is to enhance and accelerate the development, deployment, commercialization, and utilization of renewable resources for the benefit of TEP customers.

Commercialization and integration studies to help meet the accelerated REST goals for renewable resources will be prioritized. As part of TEP's long-standing commitment to renewable resources, several studies related to commercialization and integration are already underway. Those studies and ongoing experience with renewable resources will help identify additional study subjects necessary to develop the tools needed to achieve program goals.

The activities undertaken as part of this program may be supported either by TEP solely, or in partnership with other organizations and entities including private industry, public research institutions, and government laboratories. TEP intends to take full advantage of opportunities to leverage state and federal research and development efforts and support funding opportunities when planning and funding these activities. TEP will also strive to increase coordination efforts with other utilities, the U.S. Department of Energy ("DOE"), the Arizona Department of Commerce Energy Office, and national laboratories to realize greater investment of federal research funds in Arizona and, more specifically, the Tucson service territory. TEP also intends to coordinate more closely with Arizona universities to better utilize those resources.

Studies presently underway that were currently funded by the EPS (now REST) include:

- Arizona Renewable Resource Study — Jointly funded by Arizona Public Service ("APS"), Salt River Project ("SRP"), and TEP/UNS Electric, the study represents an independent analysis of potential renewable resources in Arizona.

The analysis is being conducted by leading energy engineering consulting group, Black and Veatch, and will effectively establish a baseline understanding of renewable energy resources presently perceived as available within the state. In addition, the study will define renewable energy technology applications, associated cost structures, as well as identify renewable energy market opportunities, which should encourage the development of renewable energy projects in Arizona. This study is complete.

- TEP Solar Capacity Value Study — This study drives extensive research that leverages available high-resolution solar generation data within Arizona and evaluates the potential for reliably incorporating utility-scale and customer-sited distributed solar generation into TEP's system. DOE has awarded TEP a $100,000 grant to develop a specific solar capacity value evaluation method TEP proposed based on the data noted above.

- Joint Utility Market Study — This joint effort will result in a statewide market study evaluating consumer receptiveness to the installation of distributed renewable energy equipment, particularly photovoltaic. Participants include APS, SRP, TEP/UNS Electric and the Arizona Cooperative Utilities.

- Transmission and System Integration Impacts — These studies would be designed to provide TEP/UNS Electric with a better understanding of the operational impacts, costs of integration, and the identification of opportunities with renewable energy resources in the TEP/UNS Electric generation, transmission and distribution systems. TEP/UNS Electric recognizes the critical importance of transmission in the success of the expansion of renewable generation. Any significant increase in renewable generation must be integrated into the long-term planning for transmission to be successful.

- Distribution System Impacts — These studies will examine the impacts of distributed generation resources on the power distribution system. Specific areas of study would include impacts on the general distribution system, design and construction, operations and maintenance, voltage stability, safety, power quality, and load forecasting.

## IV. COSTS OF PROGRAM IMPLEMENTATION

The TEP Plan's cost is comprised of two key cost segments, renewable generation and distributed generation. A summary of the costs of those segments and the major components for each segment are included in Attachment 3 to this Plan. As seen in Attachment 3, TEP currently estimates the cost to comply with REST at $29.8 million for 2009. Future annual increases are driven mainly by the annually increasing energy targets.

REST funding is intended to cover the cost of utility-scale renewable generation in excess of the market cost of conventional resource alternatives, incentive payments for distributed energy resources, marketing expenses, and program implementation and administration costs. The costs for renewable generation are based on TEP's most current insights into that market. The costs for DG incentives and the program budget are based on incentives developed as part of the Commission Staffs UCPP Working Group and TEP's best estimations of market uptake for the various technologies available to consumers.

The estimates contained in Attachment 3 for the Plan will be updated each year to determine the necessary level of funding from TEP's customers.

## V. CONCLUSION

Arizona is beginning the transition from a fossil-fuel based primary energy foundation to a sustainable primary energy based foundation. The transition is needed to ensure that future generations of Arizona citizens have a long-term supply of safe, affordable, convenient energy on demand. As with all transitions, the first steps are the most expensive, difficult and uncertain. Currently, all Arizona sources of renewable energy come at a cost greater than any current fossil-fuel energy source. However, due to increased use of renewable energy, the cost difference is closing and in a decade or less, renewable energy may be at economic parity with fossil fuel sources. Technical challenges to the seamless integration of time-variant renewable energy sources with dispatchable generation sources have been found. But, with proper planning, continuous data analysis and deliberate technology management, the challenges can be converted to opportunities and the path to sustainable energy integration can be smooth.

The EPS adopted by the Commission in 2001, provided TEP with the opportunity, and, just as importantly, sufficient funding to develop appropriate amounts of solar technologies, both in partnership with customers and at utility scale, to understand the basic tools that will need to be developed over the next decade to fully integrate solar energy into its generation portfolio. TEP's REST Plan and REST Tariff continue that transition to sustainable energy sources by setting a definitive, sustainable timeline and providing sufficient funding to support 15 percent of annual energy needs from renewable resources by 2025.

Arizona has the nation's best solar energy resource, wherein only 0.5 percent of Arizona's land surface, if covered with ten-percent-efficient solar generation and combined with efficient, inexpensive, reliable energy storage, could provide all of Arizona's current annual electric energy needs. Solar energy is Arizona's energy future. In 2100, we expect that future Arizonans will look back in history from their end of the timeline and wonder why there was a time when solar energy was not the energy source of choice. At our end of the timeline we know that the economics and technologies are not yet fully capable of economically and reliably supporting 100 percent of Arizona's energy needs from renewable resources. Commission approval of the REST Plan and its appropriate funding through the REST Adjustor Mechanism and the REST Tariff will challenge TEP to continue its sustainable energy transition at an accelerated pace for the next two decades. TEP looks forward to working with the Commission in fulfilling the promise of the REST Plan and REST Tariff, in working with its customers to develop DG projects throughout the Tucson service area, and in developing renewable energy as a whole.

A UniSource Energy Company

# Renewable Energy Standard and Tariff Surcharge
# REST-TS1
# Renewable Energy Program Expense Recovery

APPLICABILITY
Mandatory, non-bypassable surcharge applied to all energy consumed by all customers throughout Company's entire electric service area.

RATES
For all energy billed which is supplied by the Company to the customer, the price shall be $0.0080 per kWh of metered monthly energy consumption on all kWh consumed per meter that month up to and including a monthly cap of:

| | |
|---|---|
| For Residential class: | $4.50 per month |
| For Small General Service class: | $75.00 per month |
| For Large General Service class: | $350.00 per month |
| For Large Light and Power and Mining classes: | $1,600 per month |

Notes: (1) The Large General Service class has a minimum demand of 200 kW but less than 3,000 kW.

(2) A Large Light and Power and Mining customer is one with monthly demand in excess of 3,000 kW for the three consecutive months preceding the current billing period.

(3) Caps for Large Light and Power and Mining customers with multiple service points will be based on actual demand rather than billed demand.

For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract kWh shall be used in the calculation of the surcharge.

This charge will be a line item on customer bills reading "Renewable Energy Standard Tariff."

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

TAX CLAUSE
To the charges computed under the above rate, including any 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 Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

# Attachment 2

## Five Year Renewable Energy and Capacity Forecast with Cost Estimates (Staff Plan)

| TEP-2009 | Item | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| TEP & REST Program Factors | RES Annual Renewable Energy Percentage | 2.00% | 2.50% | 3.00% | 3.50% | 4.00% |
| | Energy Sales - MWh Growth @ 1.52%/yr | 9,935,957 | 10,135,006 | 10,325,861 | 10,519,779 | 10,679,680 |
| | Expected DSM Program Annual Energy Reductions | 63,837 | 97,308 | 131,815 | 167,496 | 220,257 |
| | Expected DG Program Annual Energy Reductions | 9,943 | 29,587 | 50,041 | 76,080 | 107,900 |
| | Net Retail Energy Sales in MWh per Year | 9,862,177 | 10,008,111 | 10,144,005 | 10,276,203 | 10,351,522 |
| | Renewable Energy - MWh | 197,244 | 250,203 | 304,320 | 359,667 | 414,061 |
| | Minimum Distributed Energy % | 15.00% | 20.00% | 25.00% | 30.00% | 30.00% |
| | Minimum Distributed Energy MWh | 29,587 | 50,041 | 76,080 | 107,900 | 124,218 |
| | Minimum Residential Distributed Energy % | 7.50% | 10.00% | 12.50% | 15.00% | 15.00% |
| | Minimum Residential Distributed Energy MWh | 14,793 | 25,020 | 38,040 | 53,950 | 62,109 |
| | Maximum Commercial Distributed Energy % | 7.50% | 10.00% | 12.50% | 15.00% | 15.00% |
| | Maximum Commercial Distributed Energy MWh | 14,793 | 25,020 | 38,040 | 53,950 | 62,109 |
| Renewable Resource Energy and Power Conversion | Residential Distributed Generation - MWp Total New 60% Solar PV | 4.814 | 9.359 | 15.145 | 22.217 | 25.843 |
| | Residential Distributed Energy - MWp Total New 40% Solar Hot Water/Space Heating & Wind | 5.917 | 10.008 | 15.216 | 21.580 | 24.844 |
| | Commercial Distributed Generation - MWp Total New 75% Solar Electric PV in 2008, 50% in 2009, 25% after | 4.351 | 3.679 | 5.594 | 7.934 | 9.134 |
| | Commercial Distributed Generation - MWp Total New 25% in 2008, 50% in 2009, 75% after, Non Solar Electric @ avg. 50% CF | 1.689 | 4.284 | 6.514 | 9.238 | 10.635 |
| | Distributed Solar Elect MWp Old With Multipliers | 1.76 | 1.76 | 1.76 | 1.76 | 1.76 |
| | Utility Solar Elect MWp Old With Multipliers | 11.11 | 11.11 | 11.11 | 11.11 | 11.11 |
| | Utility Fueled Generation - MWp Old With Multipliers | 3.938 | 3.938 | 3.938 | 3.938 | 3.938 |
| | Utility Generated @ 80% NonDispatchable Energy - MWp New No Multipliers - Wind | 47.489 | 60.997 | 72.666 | 82.444 | 98.267 |
| | Utility Generated @ 20% Fueled - MWp New No Multipliers | 2.609 | 3.351 | 3.992 | 4.529 | 5.399 |
| | Resulting Total Solar Electric Capacity in MW | 15.315 | 19.188 | 26.890 | 36.300 | 41.127 |
| | Resulting Total Solar Electric Annual Energy in MWh | 23,965 | 28,960 | 40,026 | 53,550 | 60,485 |
| | Incremental Solar Capacity Watts Installed per Year per Person | 8.153 | 4.842 | 9.627 | 11.764 | 6.033 |
| | Resulting Total Distributed Solar Water Heating Capacity in MW | 9.616 | 16.263 | 24.726 | 35.068 | 40.371 |
| | Resulting Total Distributed Solar Water Heating Annual Energy in MWh | 9,616 | 16,263 | 24,726 | 35,068 | 40,371 |
| | Resulting Total Distributed Non Solar Electric Dispatchable or Displaced Generation Capacity in MW | 1.689 | 2.856 | 4.342 | 6.159 | 7.090 |
| | Resulting Total Distributed Non Solar Electric Dispatchable or Displaced Generation Annual Energy in MWh | 7,397 | 12,510 | 19,020 | 26,975 | 31,055 |
| | Resulting Total Wind Electric Generation Capacity in MW | 47.489 | 60.997 | 72.666 | 82.444 | 98.267 |
| | Resulting Total Wind Electric Generation Annual Energy in MWh | 91,416 | 117,420 | 139,882 | 158,704 | 189,164 |
| | Resulting Total Biomass Electric Generation Capacity in MW | 6.034 | 6.776 | 7.417 | 7.954 | 8.823 |
| | Resulting Total Biomass Electric Generation Annual Energy in MWh | 52,854 | 59,355 | 64,971 | 69,676 | 77,291 |
| | Total Renewable Generating Annual Energy in MWh | **185,247** | **234,508** | **288,626** | **343,972** | **398,366** |
| | Total Renewable Generating Capacity in MW | **80.141** | **106.081** | **136.041** | **167.924** | **195.678** |
| Annual Credit Balances MWh | Residential Distributed Electric Credit Balance | 3,483 | 3,483 | 3,483 | 3,483 | 3,483 |
| | Commercial Distributed Energy Credit Balance | 0 | 0 | 0 | 0 | |
| | Utility Generated Electric Credit Balance | 117,100 | 115,500 | 113,800 | 112,000 | 110,200 |
| Assumption | Residential Distributed Generation Solar Electric % | 60.00% | 60.00% | 60.00% | 60.00% | 60.00% |
| Residential Solar Electric Up Front Subsidy Payment UCPP Plan | Residential Distributed Genration Up Front Solar Electric Subsidy Program $/Watt DC | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 |
| | Additional Residential Distributed Solar Electric Capacity Needed in MWp given Year | 4.365 | 4.545 | 5.787 | 7.071 | 3.626 |
| | Subtotal Cost of Residential Distributed Solar Electric Subsidies | $13,095,402 | $13,636,018 | $17,359,656 | $21,213,394 | $10,878,757 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Distributed Solar Hot Water & Wind Up Front Subsidy Payment UCPP Plan | Residential Distributed Solar Hot Water & Wind Up Front Subsidy Program $/Watt AC Equivalent | $0.5000 | $0.5000 | $0.5000 | $0.5000 | $0.5000 |
| | Additional Residential Distributed Solar Hot Water & Wind Capacity Needed in MWp given Year | 3.929 | 4.091 | 5.208 | 6.364 | 3.264 |
| | Subtotal Cost of Residential Distributed Solar Hot Water & Wind Subsidies | $1,964,310 | $2,045,403 | $2,603,948 | $3,182,009 | $1,631,814 |
| Assumption | Distributed Generation Solar Electric % | 75.00% | 75.00% | 75.00% | 75.00% | 75.00% |
| Distributed Generation Solar Electric Performance Based Incentive Plan - Applies to all non residential solar electric in all years. UCPP & Self-Directed Funding | SubTotal Cost of Distributed Solar Electric Generation Performance Based Incentive | $3,412,092 | $6,187,651 | $10,809,514 | $16,393,345 | $22,821,641 |
| | Unit Built in 2008 | $1,150,596 | $1,150,596 | $1,150,596 | $1,150,596 | $1,150,596 |
| | Unit Built in 2009 | $1,997,091 | $1,997,091 | $1,997,091 | $1,997,091 | $1,997,091 |
| | Unit Built in 2010 | | $3,039,964 | $3,039,964 | $3,039,964 | $3,039,964 |
| | Unit Built in 2011 | | | $4,621,862 | $4,621,862 | $4,621,862 |
| | Unit Built in 2012 | | | | $5,583,832 | $5,583,832 |
| | Unit Built in 2013 | | | | | $6,428,295 |
| | Unit Built in 2014 | | | | | |
| | Unit Built in 2015 | | | | | |
| | Unit Built in 2016 | | | | | |
| | Unit Built in 2017 | | | | | |
| | Unit Built in 2018 | | | | | |
| | Unit Built in 2019 | | | | | |
| | Unit Built in 2020 | | | | | |
| | Unit Built in 2021 | | | | | |
| | Unit Built in 2022 | | | | | |
| | Unit Built in 2023 | | | | | |
| | Unit Built in 2024 | | | | | |
| | Unit Built in 2025 | | | | | |
| | Performance Based Incentive Rate for 20 years $/kWh | $0.1800 | $0.1620 | $0.1620 | $0.1380 | $0.1380 |
| Distributed Generation Non Solar Electric Energy Performance Based Incentive Plan - Solar Thermal, Solar Cooling, Wind, Biomass & Daylighting. Applies to all non residential solar electric in all years. UCPP & Self-Directed Funding | SubTotal Cost of Non Solar Electric Distributed Energy Performance Based Incentive | $315,934 | $572,931 | $1,000,881 | $1,540,382 | $2,161,473 |
| | Unit Built in 2008 | $106,537 | $106,537 | $106,537 | $106,537 | $106,537 |
| | Unit Built in 2009 | $184,916 | $184,916 | $184,916 | $184,916 | $184,916 |
| | Unit Built in 2010 | | $281,478 | $281,478 | $281,478 | $281,478 |
| | Unit Built in 2011 | | | $427,950 | $427,950 | $427,950 |
| | Unit Built in 2012 | | | | $539,501 | $539,501 |
| | Unit Built in 2013 | | | | | $621,091 |
| | Unit Built in 2014 | | | | | |
| | Unit Built in 2015 | | | | | |
| | Unit Built in 2016 | | | | | |
| | Unit Built in 2017 | | | | | |
| | Unit Built in 2018 | | | | | |
| | Unit Built in 2019 | | | | | |
| | Unit Built in 2020 | | | | | |
| | Unit Built in 2021 | | | | | |
| | Unit Built in 2022 | | | | | |
| | Unit Built in 2023 | | | | | |
| | Unit Built in 2024 | | | | | |
| | Unit Built in 2025 | | | | | |
| | Performance Based Incentive Rate for 20 years $/kWh | $0.0500 | $0.0450 | $0.0450 | $0.0400 | $0.0400 |
| TEP Generated Renewable Power | Above Market Premium of Self Generated or Purchased Renewable Power | $0.0431 | $0.0431 | $0.0431 | $0.0431 | $0.0431 |
| | Purchased Transmission | $480,000 | $1,920,000 | $1,920,000 | $1,920,000 | $1,920,000 |
| | Cost of Self Generated or Purchased Renewable Power | $6,694,977 | $9,535,263 | $10,744,825 | $11,758,333 | $13,398,587 |
| Other RES Program Costs | Grid Integration Rate in $/MWh | $0.00 | $0.00 | $2.00 | $3.00 | $4.00 |
| | Large Scale Grid Integration Costs in $ | $0.00 | $0.00 | $228,240 | $377,650 | $579,685 |
| | Administrative Costs & Integration Costs & Outreach and Advertising & Net Metering costs | $4,203,340 | $6,695,787 | $8,630,410 | $10,865,010 | $12,136,382 |
| GreenWatts Projects | Distributed non-residential community sited PV UFI projects funded with GreeWatts proceeds | $127,047 | $135,517 | $143,987 | $152,456 | $152,456 |
| Self-Directed Funding | Self-Directed Funding Projects at same $/kWh as Feed-In Tariff Plan above. Included in that item, broken out seprately here. | $210,000 | $400,000 | $1,000,000 | $1,000,000 | $1,000,000 |
| DG Program Subtotal | Distributed Generation & DG Admin and DG Integration Program Costs | $23,118,125 | $29,273,306 | $40,320,155 | $52,968,945 | $49,202,837 |
| Distributed Program % of Total Program | DG Percent of Total REST Program Costs | 77.54% | 75.43% | 78.61% | 81.36% | 77.88% |
| Total Program Expenses | Total REST Program Cost | $29,813,103 | $38,808,570 | $51,293,220 | $65,104,929 | $63,181,109 |
| Program Revenue Streams | Credit Sales MWh | 0 | 0 | 0 | 0 | 0 |
| | Green Sales MWh | 1,500 | 1,600 | 1,700 | 1,800 | 1,800 |
| | Credit Sales $/MWh | $0 | $0 | $0 | $0 | $0 |
| | Green Sales $/MWh | $85 | $85 | $85 | $85 | $85 |
| | Renewable Product Sales Income - GreenWatts for Community Sited Commercial UFI PV only | $127,047 | $135,517 | $143,987 | $152,456 | $152,456 |
| | EPS Carryover Revenue | $0 | $0 | $0 | $0 | $0 |
| | REST Surcharge/Sample Tariff Income | **$29,643,567** | **$40,800,000** | **$53,050,000** | **$62,300,000** | **$54,850,000** |
| | Value of TEP PV Energy at $50/MWh (incl SGSSS) | $429,250 | $429,250 | $429,250 | $429,250 | $429,250 |
| | PV O&M Exp @ $50/MWh | ($40,000) | ($40,000) | ($40,000) | ($40,000) | ($40,000) |
| | Investment Tax Credit | $0 | $0 | $0 | $0 | $0 |
| | Finance Cost @ 10% or Investment @ 5% | ($630) | ($17,936) | ($142,849) | ($250,208) | ($124,536) |
| | Total REST Program Revenue | $30,159,234 | $41,306,831 | $53,440,387 | $62,591,499 | $55,267,170 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Annual Program $ Balance | Total REST Program Annual Balance (Subsidy Program) | $346,131 | $2,498,261 | $2,147,167 | ($2,513,430) | ($7,913,939) |
| Cumulative Program $ Balance | **Cumulative Gain (Loss) (Subsidy Program)** | $358,724 | $2,856,985 | $5,004,152 | $2,490,722 | ($5,423,217) |
| Cumulative Program Cost | **Cumulative REST Program Expenditures** | $40,264,400 | $79,072,970 | $130,366,190 | $195,471,119 | $258,652,228 |

| Variable Assumptions | | | |
|---|---|---|---|
| | Landfill Gas MWp | MWp | |
| | Central Solar Conversion Rate | MWh/MWp | |
| | Distributed Solar Conversion Rate | MWh/MWp | |
| | Distributed Renewable Conversion Rate | MWh/MWp | OG Energy Rate |
| | Solar Thermal Conversion | MWh/MWp | |
| | Dispatchable Conversion Rate | MWh/MWp | |
| | Wind Conversion Rate | MWh/MWp | |

Program Assumptions

Assumptions:
TEP manages the Distributed Generation ("DG") program.
Residential DG: 60% solar electric; 40% solar hot water and wind - Funded by an up-front subsidy through 2012.
Commercial DG: 25% solar electric; 75% solar hot water heating, solar cooling, wind, biomass or day lighting – Funded by 20-year locked performance-based incentive after 2007 through 2030.
Springerville Solar System has ceased as commercial DG, but multipliers count.

All banked landfill gas credits, including those from multipliers, will be useful in subsequent years for meeting REST or GreenWatts needs, or for sale.
The cost of renewable energy purchased through RFPs and generated by TEP in the future initially will be $0.0455 per kWh above the market price for energy purchase at the same time the renewable energy was generated.
The cost of transmission after 2012 to bring the needed amounts of 50% wind to Tucson will be based on transmission costs of $0.035 cents per kWh on a 20% capacity factor line, in 2013 with reduction to market in 2030.
All renewable generation sources for TEP can be integrated into the existing transmission structure through 2012.
This scenario does not include reductions from Global Solar credit production.
Energy sales and subsidy revenue growth is 1.52% per year: Assumes REST reduces customer energy loan growth due to the new generation installed to meet REST; and DSM reduces load growth.
Annual energy production rates for the various technologies are based on historical data from the first five years of the TEP EPS programs.
The Performance Based Incentive Program has less risk of problems associated with customer generation production than the Up Front Subsidy Program, given that there is no expiration date.

Grid Integration costs are based on Xcel/Minnesota Dept of Commerce Report of 2004, Idaho Power Report of 2007, and British report of 2006.
Other REST Program Costs include: Interconnection application review costs, net metering costs, application processing costs, initial inspections, annual plan and reporting costs and compliance hearing costs.
There is no energy storage anticipated during the 2008 through 2015 time frame.
Storage will be needed after 2015, if unpredictable energy sources, like wind or solar, are supplant coal generation.
Administrative costs assume one person per 500/kWp per year of new commercial or residential solar installations and two technical gurus for all levels of installations.
Ongoing annual inspection and repair work will be contracted out.
Creation of a database with online access for customers and installers will add some costs in future.

# Attachment 3

**TEP Renewable Energy Standard Tariff**
**Cost Recovery Factors Definition for 2009**

1/1/2009

**Total REST Compliance Plan Budget 2009: $ 29,686,056**

| | REST Implementation Plan |
|---|---|
| **Purchased Renewable Energy:** | |
| Above Market Cost of Conventional Generation calculated annually on hourly data per MCCCG Matrix [aa] | $6,214,977 |
| Transmission direct-use cost [ab] | $480,000 |
| Transmission line-loss cost | $0 |
| Grid management ancillary services and day-ahead unit commitment cost | $0 |
| Grid stability analysis cost allocation [ac] | $10,000 |
| Fuel and maintenance $ assoc. w/ increased CT use and load range ramp cycles to manage over/under scheduled RE | $0 |
| RFP preparation, issue and evaluation cost [ad] | $10,000 |
| Independent Auditor cost [ae] | $25,000 |
| Loss of revenue from off-system sales due to transmission constraints created by transmission alloc. to RE PPA | $0 |
| Labor overhead allocation cost for purchased renewable power contracts [af] | $50,000 |
| In-state renewable resource economic development premium payment cost | $0 |
| **Total** | **$6,789,977** |
| **Customer Sited Distributed Renewable Energy:** | |
| Up-front subsidy payment to customers' cost[ba] | $15,059,712 |
| Annual production-based performance payment to customers' cost [bb] | $3,728,026 |
| Builder solar energy system program[bc] | $300,000 |
| Interconnection and net meter application processing labor cost [bd] | $187,500 |
| Acceptance testing cost [be] | $750,000 |
| Customer technical support cost [bf] | $225,000 |
| Annual meter reading cost [bg] | $92,000 |
| Support tools, materials, transportation and supply cost [bh] | $100,000 |
| Direct internal labor cost for administration of the customer sited renewable generation program [bi] | $237,500 |
| Outside services and internal labor for outreach, marketing materials, education and website maintenance cost [bj] | $1,000,000 |
| Grid management cost | $0 |
| Grid stability analysis cost allocation [bk] | $100,000 |
| Cost-of-service contracts for outside labor for inspections and maintenance [bl] | $100,000 |
| **Total** | **$21,879,739** |
| **Customer Care and Billing program (CC&B):** | |
| Annual administrative CC&B cost database upgrades [ca] | $50,000 |
| Initial database and customer interface program development and program revision cost [cb] | $0 |
| Capital A&G load allocations for above development work [cc] | $0 |
| CC&B incremental transaction allocation cost for CC&B support [cd] | $50,000 |
| **Total** | **$100,000** |
| **Energy Management System and Energy Accounting and Settlements (EMS&EAS):** | |
| Annual administrative EMS & EAS cost allocation based on share of transactions processed [da] | $25,000 |
| Initial database and program revision cost [db] | $200,000 |
| Capital A&G load allocations for above development work [dc] | $25,000 |
| Labor overhead allocation cost for EMS & EAS [dd] | $25,000 |
| **Total** | **$275,000** |
| **Net Metering:** | |
| Direct material cost for meters [ea] | $80,226 |
| Labor cost for meter installations [eb] | $40,113 |
| Direct energy credit purchase cost | $0 |
| Net metering rate design cost | $0 |
| Time-of-Use Net Metering Program development cost [ed] | $0 |
| Net Metering data interval recording for load research and program metrics evaluation [ee] | $0 |
| Communications for Net Metering data retrieval [ef] | $0 |
| **Total** | **$120,340** |

**Reporting:**

| | |
|---|---|
| Annual Compliance Report and hearing cost [fa] | $25,000 |
| Annual Planning and Implementation Report and hearing cost [fb] | $50,000 |
| Annual Tariff review and hearing cost [fc] | $50,000 |
| Labor overhead and CC&B transaction allocation cost for reporting [fd] | $12,500 |
| **Total** | **$137,500** |

**Outside Coordination and Support:**

| | |
|---|---|
| Support provided to University research projects (eg. AzRise) [ga] | $200,000 |
| Support through providing information and answering questions of national energy labs cost [ga] | $25,000 |
| Support through providing information and testing equipment of renewable energy equipment vendors cost [gb] | $15,000 |
| Responding to renewable energy questions from non TEP customers' cost [gc] | $0 |
| Support of outside service territory renewable energy interest cost [gd] | $0 |
| WREGIS and other renewable energy certification agency fee cost | $0 |
| Utility Wind Interest Group fee cost [ge] | $5,000 |
| Solar Electric Power Association fee cost [gf] | $4,500 |
| Other renewable energy association fees as needed cost [gg] | $10,000 |
| Training, travel, memberships, periodicals, etc. cost [gh] | $20,000 |
| Labor overhead allocation cost for outside coordination and support [gi] | $4,000 |
| **Total** | **$283,500** |

**Renewable Energy Hardware Development:**

| | |
|---|---|
| Technology development projects – geothermal heat pumps, residential solar units, residential wind generation, etc. cost [ha] | $50,000 |
| Energy storage demonstration project cost [hb] | $0 |
| Operation and maintenance of renewable generation systems cost [hc] | $50,000 |
| Renewable energy resource monitoring program cost [hd] | $0 |
| Support of Arizona-wide renewable energy studies cost [he] | $0 |
| Up-front funded renewable technology construction cost [hf] | $0 |
| Development of wind and solar forecasting program costs [hg] | $0 |
| Development of load-shed systems for managing rapid changes in renewable energy generation levels cost [hh] | $0 |
| Property taxes, sales taxes and insurance for renewable energy hardware costs [hi] | $0 |
| Labor overhead, Stores loads, allocation cost for renewable energy hardware development [hj] | $0 |
| **Total** | **$100,000** |

| | |
|---|---|
| **Grand Total** | **$29,686,056** |

Notes:

aa: 144,270 MWh @ $43.08 per MWH above cost of MCCCG – Purchased Power. Contracts are in addition to existing power purchase contracts, costs are incremental and caused by renewable purchased power contracts.

ab: Cost of acquiring transmission from a third party provider for the 4th quarter of 2009.

ac: Annual analysis of hourly delivery intermittencies on grid stability, forecasting development – internal TEP personnel, 125 hours. Evaluation time is in addition to existing power purchase analysis and due to time variant nature of wind power.

ad: Internal development, review, posting, query response, evaluation, contract development and close out – internal TEP personnel, 120 hours. RFPs are in addition to existing power purchase RFPs, costs are incremental and caused by renewable purchased power.

ae: Historic cost basis.

af: Contract administration, settlement review, payment approval, internal overhead – internal TEP personnel, 200 hours. Contracts are in addition to existing power purchase contracts, costs are incremental and caused by renewable purchased power contracts.

ba: Residential – est. 60% will be PV. 4.365 MWDC of PV in 2009. @ $4.50 per watt DC = $19.6M. 40% will be SDWH 3.929 MWp of SDWH in 2009. @ $1.00 per watt = $3.93M. (Excludes Builder Program of $0.3M included in line bc.)

bb: Commercial PBI: Solar PV – 50% * 7.4 GWh/yr/ @ $0.18 = $1.33M. The other commercial as thermal – 50% * 7.4 GWh @ $0.05/kWh = $0.37M. Additional payments from 2008 add to $1.15M for PV and $0.1M for other. These numbers are grossed up for a full 12 months, bringing the total to $3.2M for Commercial PBI.

bc: Assumes an incremental .50 /watt DC for 200 homes with an average panel size of 3kWDC. ($300k)

bd: assume 3.5 FTE - 1500 PV units & 2000 hot water/wind @ 1000 units/person/year. Currently 200 units/person/year productivity.

be: assume 7 FTE - 1500 PV units & 2000 hot water/wind @ 500 units/person/year. Currently 200 units/person/year productivity.

bf: assume 3 FTE - 1500 PV units & 2000 hot water/wind @ 1167 units/person/year + commercial. Currently 200 units/person/year productivity.

bg: 1500 meter reads per year including reporting and processing of data into reports

bh: Vehicles, small tools, and consumables for 4 mobile units

bi: 3 supervisory/managerial people @ 1,671 units/person/year. Currently 200 units/person/year productivity.

bj: Direct-outreach education expense with providers. Includes media purchases, printing, and design.

bk: Studies of solar time-variant output impact on distribution grid. Review of solar capacity value. Used for matching grant funding. 0 person assigned.

bl: Used for annual inspections, customer support. Based on historic costs extrapolated to 1,200 customers from $25,000/year for 300 customers.

ca: Initial estimate – discovery in progress - new programming.

cb: 2008 Estimated cost @ $400k.

cc: Initial estimate – discovery in progress.

cd: Initial estimate – discovery in progress - database upgrades.

da: Initial estimate – discovery in progress.

db: Initial estimate – discovery in progress.

dc: Initial estimate – discovery in progress.

**dd: Initial estimate – discovery in progress.**

**ea: approximately 1500 net meters @ $50 per meter**

**eb: 400 site installations @ $100 per site.**

**ec: Initial estimate – discovery in progress. Recovery over 1-year period.**

**ed: Initial estimate – discovery in progress. Recovery over 1-year period.**

**ee: Future One-Quarter time for an energy analyst to collate data, prepare analysis and review cost impacts and effect on lost revenues of net metering.**

**ef: Future .25 FTE for an energy analyst for on going program review and quality control review of net metering program.**

**fa: Historic cost basis, extrapolated to a larger program with more reporting factors.**

**fb: Historic cost basis, extrapolated to a larger program with more reporting factors.**

**fc: Historic cost basis, extrapolated to a larger program with more reporting factors.**

**fd: Calculated as 10% of internal labor costs.**

**ga: Funding support for projects to fund renewable research at such entities as AzRise.**

**gb: Historic cost basis, extrapolated to a larger program with more reporting factors. Program manager level respondent.**

**gc: Historic cost basis, extrapolated to a larger program with more reporting factors. Program manager level respondent.**

**gd: Historic cost basis, extrapolated to a larger program with more reporting factors. Administrative level respondent.**

**ge: Based on proposal.**

**gf: Historic based.**

**gg: Historic based. Biomass, geothermal, etc.**

**gh: Historic based for 4 employees.**

**gi: Calculated as 4.4% of internal labor costs.**

**ha: Estimated based on project size and mix.**

**hb: Estimated based on project size and mix.**

**hc: Historic based. OH, DAMP and SASS**

**hd: Historic based.**

**he: Historic based.**

**hf: Operating Headquarters Test Yard – 0 kid**

**hg: Matching funds for grants in application.**

**hh: Matching funds for grants in application.**

**hi: Historic based.**

**hj: Calculated as 10% of internal labor costs = $0 plus 2% of transaction costs = $0 Total = $0**